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November 29, 2013

Honorable Kimberly D. Bose
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E., Room 1A
Washington, D.C. 20426

Re: *PJM Interconnection, L.L.C.*, Docket No. ER14-504-000

Dear Ms. Bose:

PJM Interconnection, L.L.C. ("PJM"), pursuant to section 205 of the Federal Power Act ("FPA"), 16 U.S.C. § 824d, hereby submits revisions to the PJM Open Access Transmission Tariff ("Tariff") and the Reliability Assurance Agreement Among Load Serving Entities in the PJM Region ("RAA") to correct an aspect of 2011 changes to the Reliability Pricing Model ("RPM") that, by setting minimum requirements for the highest availability capacity product, has unintended adverse implications for the PJM Region's long-term ability to procure the quantities of that product needed to assure reliability.[1] PJM is required to post on February 1, 2014, the planning parameters that will be used in the RPM Base Residual Auction ("BRA") scheduled for May 2014. As this filing will modify those planning parameters, the enclosed revisions reflect an effective date of January 31, 2014, which is more than 60 days after the date of this filing.

I. INTRODUCTION AND SUMMARY

Since its introduction in 2007, RPM has performed well in attracting new capacity, arming owners of existing resources with essential pricing information to guide their investment and retirement decisions, and opening an unparalleled source of value and opportunity for a rapidly developing demand response industry. As the Commission knows, PJM and its stakeholders have devoted countless hours to continually reviewing, refining and improving the RPM market rules so that RPM continues to serve the region's resource adequacy needs. The purpose of this filing is to correct a mis-step in one aspect of the technical auction-clearing rules from an earlier round of otherwise

[1] PJM today also is filing Tariff and RAA revisions to recognize in PJM's capacity auctions the transmission system's limits on the delivery into PJM of capacity offers from external generation resources. Although PJM requests approval of both filings, the two filings address separate issues and are, both legally and practically, independent of each other.

successful RPM improvements, which is now working at cross-purposes with one of RPM's most fundamental characteristics—a downward sloping demand curve.

The Commission accepted a sloped demand curve when it first approved RPM, and has approved its use to clear capacity auctions of other Independent System Operators and Regional Transmission Organizations ("RTOs and ISOs"), because, among other benefits, sloped demand curves provide a good indication of the incremental value of capacity at different capacity levels, and reflect an expectation that capacity sometimes will be procured in excess of the target reliability requirement. As discussed in detail below, the Commission has found, a sloped demand curve increases the likelihood that reserve margins will be consistently met, and reduces overall costs in the long run by reducing capacity price volatility.

Certain RPM changes introduced in 2011, however, have severely blunted the impact of the sloped demand curve and seriously threaten continued realization of the benefits of a sloped curve. At that time, PJM implemented new demand resource products with differing levels of availability, regarding when, how often, and for how long, the demand resource can be called for load reductions. PJM also proposed, and the Commission approved, procedures and formulae for PJM to determine each year the maximum amount of the more-limited products that can be committed to PJM without impairing reliability. However, instead of using those "Reliability Targets" as *caps* on the more-limited Demand Resources, PJM subtracted those values from the overall capacity requirement, and set the resulting value as a *floor* on the less-limited capacity product. This one subtle distinction in the 2011 Demand Resource product rules, it turns out, has far-reaching adverse effects.

Specifically, by setting a minimum required megawatt ("MW") level in each RPM Auction for the product with the greatest availability (i.e., "Annual Resources," which can include generation, demand response, or energy efficiency), the auction rules virtually guarantee that every time Annual Resources have to be paid a price-premium in order to satisfy the minimum requirement, the auction algorithm will immediately turn to clearing the lower-availability products as soon as the minimum for the higher-availability products is met, because by definition the lower-availability products have a lower cost. Ironically, under the current rules, a price premium for Annual Resources *is a sure sign that the resulting price signal is being suppressed*, because it is an unerring indication that the auction algorithm is preferentially clearing lower-cost, lower-availability products for the region's capacity needs between the vertical line at the minimum requirement for Annual Resources and the total cleared capacity quantity at the Commission-approved sloped demand curve. Moreover, the preference for lower-availability products is exacerbated by another (otherwise highly commendable) feature of the 2011 rules—an option for Demand Resource providers to submit coupled offers for a single resource that can qualify as two or more product types. Under that option (which PJM *does not* propose to change here), the auction will *automatically* select the lower-priced, lower-availability aspect of the offer, because satisfaction of the minimum requirement for higher-availability products frees it to seek out the lowest-price offers remaining.

As a result, PJM has inadvertently established a *vertical* demand curve at the minimum requirement for Annual Resources, which interjects itself at least every time Annual Resources get a price premium, and makes it far less likely that Annual Resource offers will intersect with, and be valued by, the sloped demand curve. The same unfortunate consequence will arise at least every time the intermediate product, known as Extended Summer Demand Resources ("Extended Summer DR"), earns a price premium above the lowest-availability product, known as Limited Demand Resources ("Limited DR"). In that case, a vertical demand curve arises at the minimum requirement for the combined amount of Extended Summer DR and Annual Resources, and makes it more difficult for both of those higher-availability product types to intersect with the sloped demand curve. And even when *no* prices separate, every megawatt of lower-availability resources that clears beyond the reliability target for that resource type displaces a megawatt of Annual Resources, so that the eventual sloped-curve intersection point, and price signal, is not an Annual Resources price signal, but instead a price signal that depends on commitment of lower-availability resources *above* the level that PJM has identified as consistent with reliability.

PJM presents with this filing the affidavit of Professor Benjamin F. Hobbs who provided critical theoretical support at the initiation of RPM for the sloped demand curve that RPM still uses today. He now confirms that PJM has indeed reintroduced a vertical demand curve, and that the new vertical curve will yield much lower reliability at higher cost than if PJM modified the rules to ensure that Annual Resources could again significantly interact with the sloped demand curve. Professor Hobbs' valuable insights should not even be needed at this point because Commission support for sloped demand curves is so well established. Further, no policy innovation is needed to correct PJM's earlier mis-step and reintroduce the sloped demand curve to the Annual Resources that are available year-round and that comprise roughly 90 percent of the region's resource base. The re-introduction of the sloped demand curve that PJM proposes in this filing will not affect the quantities of Demand Resources clearing in the RPM Base Residual Auction up to the target reliability requirement for the PJM Region. As shown in simulations of the proposed changes, the composition of Demand Resources clearing changes from lower-availability Limited Demand Resources to higher-availability Extended Summer Demand Resources, which also improves reliability in addition to bringing the sloped demand curve to Annual Resources.

To make this correction, PJM is proposing to change the process by which resources clear in an RPM Auction such that the more-limited resources will only be allowed to clear up to a pre-determined ceiling. Accordingly, PJM is retiring the minimum resource requirements and proposing binding resource constraints for the more-limited resources (i.e., Limited and Extended Summer DR). PJM proposes to implement these changes starting with the BRA to be held in May 2014 for the 2017/2018 Delivery Year.

II. BACKGROUND

A. The Downward-Sloping Demand Curve Was Approved By The Commission As An Essential Feature Of RPM To Maintain Reliability.

Nearly seven years ago, the Commission accepted a settlement that established the Reliability Pricing Model.[2] In doing so, the Commission expressly approved a key feature of RPM—use of a downward sloping demand curve to clear the three-year forward BRA. The evidence provided by PJM showed, and the Commission agreed, that the sloped demand curve was a marked improvement over PJM's previous capacity rules that essentially created a "vertical curve" by requiring load serving entities to provide a specific minimum quantity of capacity or pay a deficiency charge. In its orders on RPM and the capacity markets of other RTOs and ISOs, the Commission (as shown below) has repeatedly acknowledged the benefits of a downward-sloping demand curve, as has a federal court of appeals in a case that solely concerned whether use of a downward sloped demand curve is just and reasonable.

In the original RPM proceedings in 2005 and 2006, PJM presented the affidavit of Professor Hobbs and his extensive simulations to assess the relative performance and cost of vertical and downward sloping demand curves.[3] Professor Hobbs explained that the sloped demand curve presents several advantages over a vertical demand curve, including that "it is broadly reflective of the reality of an increasing social value of capacity as reserve margins shrink; it creates a stable investment environment—which reduces the cost of capital and saves consumers money; and it lessens incentives for exercise of market power in capacity markets."[4]

Professor Hobbs showed that downward-sloped demand curves provide reliability benefits over vertical demand curves by valuing incremental capacity in excess of the reserve margin, thereby ensuring a much greater likelihood that adequate capacity resources will be acquired year-over-year. Professor Hobbs explained that "[a]dditional capacity [above the reserve margin] has value" because, among other reasons, "in the face of varying load growth, weather, and capacity availability, the probability of available capacity being less than what is required to meet load and operating reserves never reaches zero, even for large reserve margins;" in other words, "reserves beyond the

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2 *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079, at PP 6, 104 (2006) ("*RPM Settlement Order*"), *order on reh'g*, 119 FERC ¶ 61, 318, *reh'g denied*, 121 FERC ¶ 61,173 (2007) *petition for review denied sub nom. Pub. Serv. Elec. & Gas Co. v. FERC*, No. 07-1336 (D.C. Cir., Mar. 17, 2009).

3 Reliability Pricing Model Filing of PJM Interconnection, L.L.C., Docket Nos. ER05-1440-000 and EL05-148-000, Affidavit of Professor Benjamin F. Hobbs (Aug. 31, 2005) ("2005 Hobbs Affidavit").

4 2005 Hobbs Affidavit at 6:9-12.

target are valuable for reducing risk of capacity shortfalls."[5] Further demonstrating the reliability benefits of a sloped demand curve, Professor Hobbs conducted extensive simulations and found that the likelihood of meeting the established reserve requirement was much higher with a sloped demand curve than with a vertical curve.[6] He also conducted numerous sensitivity analyses, varying key assumptions in the model, and found that in every case, a sloped curve still provided greater assurance of reliability than did a vertical curve.[7]

Moreover, as Professor Hobbs showed, the sloped curve's greater assurance of reliability would come at a reduced cost. He explained that the sloped-demand curve yields a more stable and less volatile stream of capacity payments over time, such that risk-averse investors are likely to accept lower rates of return, which reduces the costs to consumers of meeting resource adequacy requirements.[8] By contrast, he showed that, under PJM's then-existing vertical demand curve approach, capacity prices can change dramatically with small supply changes around the fixed reserve requirement. In other words, prices can increase to the deficiency charge rate even when aggregate supplies fall just slightly short of the reliability requirement, and, conversely, prices can plunge to near zero when aggregate supplies are just slightly above the reliability requirement.[9]

Professor Hobbs also supported these conclusions through his extensive simulations. Under his base case assumptions, and under all of his sensitivity cases, the sloped curve resulted in lower cost to consumers.[10]

Accordingly, Professor Hobbs concluded that "downward sloping curves result in more favorable performance in terms of average reserve margins, consumer costs, and year-to-year variations in these indices,"[11] while vertical demand curves "produce[] higher long-run consumer costs,"[12] because capacity resources are exposed to "[v]olatile revenues that cannot be hedged."[13]

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5 2005 Hobbs Affidavit at 12:7-11.

6 *Id.* at 34:22-35:2, 40:14-41:2.

7 *Id.* at 3:25-4:4, 7:3-7:9, 44:9-47:6.

8 *Id.* at 41:20-22.

9 *Id.* at 60:7-63:14.

10 *Id.* at 3:25-4:4, 44:8-63:14.

11 2005 Hobbs Affidavit at 6:22-23.

12 2005 Hobbs Affidavit at 7:7-8.

13 2005 Hobbs Affidavit at 12:23. Professor Hobbs also explained that "reserves beyond the target lessen the risk of large suppliers being pivotal or otherwise able to exercise market power." *Id.* at 12:4-5.

In the *RPM Settlement Order*, the Commission fully endorsed Professor Hobbs' showings of the benefits of a downward sloping demand curve, finding that:

> A downward-sloping demand curve would reduce capacity price volatility and increase the stability of the capacity revenue stream over time. This is because, as capacity supplies vary over time, capacity prices would change gradually with a sloped demand curve. By contrast, under the current capacity construct, [which used a vertical demand curve,] capacity prices vary substantially between the deficiency charge and zero even though supply varies only slightly between a slight deficit below IRM and a slight surplus above IRM. The lower price volatility under the sloped demand curve would render capacity investments less risky, thereby encouraging greater investment and at a lower financing cost. In addition, we agree with PJM that a downward-sloping demand curve provides a good indication of the incremental value of capacity at different capacity levels. For example, incremental capacity above the IRM is likely to provide additional reliability benefits, which is reflected in the positive prices in the sloped demand curve to the right of IRM, but is not reflected in the current [vertical demand curve] construct. Finally, as we discussed in orders in which a sloped demand curve was approved for NYISO, a sloped demand curve would reduce the incentive for sellers to withhold capacity in order to exercise market power when aggregate supply is near the IRM.[14]

In addition, the Commission has recognized that:

> The purpose of using the [sloped demand] curve is to reduce capacity volatility, thereby reducing the risk and the financing cost of investment, to the benefit of customers. Implicit in this curve is the expectation that PJM will sometimes procure in excess of its Reliability Requirement if additional capacity can be procured at sufficiently low prices. The [sloped demand] curve also allows PJM to procure less capacity than its Reliability Requirement when the price needed to procure capacity is sufficiently high. Under the

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[14] *RPM Settlement Order* at P 104 (citing *N.Y. Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, at P 67 (2003)). The Commission further explained that "[w]ithholding capacity would be less profitable under a sloped demand curve because withholding would result in a smaller increase in capacity prices. By contrast, under the existing [vertical demand curve] construct, small changes in capacity near the IRM can result in a very large capacity price increase, so that withholding can be significantly more profitable under these supply conditions." *Id.*

> [sloped demand] curve, it is to be expected that PJM will procure more capacity than the Reliability Requirement in some years (when supplies are plentiful and offered at comparatively low prices) and will occasionally procure less capacity than the Reliability Requirement in other years (when supplies are less plentiful and offered at higher prices).[15]

The Commission similarly recognized and endorsed the benefits of a sloped demand curve for the New York Independent System Operator, Inc.'s ("NYISO") capacity market, which determination was specifically upheld by a federal appellate court.[16] In *ELCON*, the court noted that, similar to PJM's pre-existing capacity construct, NYISO's former approach of using a fixed reserve obligation enforced by a deficiency charge "resulted in a vertical demand curve for ICAP, with the price equal to $255 for all quantities up to 118%, and $0 for all quantities exceeding 118%."[17] Beating back all arguments that the sloped curve was not just and reasonable, the reviewing court found no fault in the Commission's findings that: (1) "the ICAP Demand Curve encourages investment in new generation capacity by ensuring 'increased stability in ICAP revenues;'" (2) that the sloped curve "restructures ICAP prices to 'more realistically reflect[ ] the economic value of capacity reserves' and to 'send better price signals to encourage the construction of generation before a shortage occurs;'" and (3) that "stable ICAP revenues will reduce the risk and cost of financing investment in new generation capacity and thus reduce the cost of electricity to consumers in the long term."[18]

In short, it was specifically intended that RPM use a sloped demand curve to properly value capacity beyond the reserve margin and provide much greater assurance that resource adequacy goals will be met. The reliability and other benefits of a sloped demand curve are well-established in Commission and judicial precedent.

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15 *PJM Interconnection, L.L.C.*, 129 FERC ¶ 61,090, at P 71 (2009) (footnote omitted) (citing *RPM Settlement Order* at P 104).

16 *N.Y. Indep. Sys. Operator, Inc.*, 103 FERC ¶ 61,201, *reh'g denied*, 105 FERC ¶ 61,108 (2003), *aff'd, Elec. Consumers Res. Council v. FERC*, 407 F.3d 1232 (D.C. Cir. 2005) ("*ELCON*").

17 *ELCON* at 1234.

18 *Id.* at 1237-38 (alteration in original) (citations omitted).

B. The Commission Has Permitted Resources With Substantial Limitations On Their Availability To Become Capacity Resources, While At The Same Time Approving PJM Rules That Identify The Maximum Commitment Level Of Those Resources Consistent With Maintaining Reliability.

Prior to 2011, all Demand Resources eligible to offer capacity into RPM were available only from June through September of each Delivery Year, no more than ten times, and for no more than six hours at a time.[19] In 2011, the Commission approved PJM's proposal to establish two new, less limited, types of Demand Resources, known as Extended Summer DR and Annual Demand Resource ("Annual DR").[20] With the approval of these revisions, Capacity Market Sellers can offer Limited Demand Resource ("Limited DR"),[21] Extended Summer DR[22] and Annual Resources (including generation, energy efficiency, and Annual DR[23]).

PJM also proposed, and the Commission accepted, explicit targets for the maximum quantity of Limited DR (i.e., the pre-existing product with the most limits on its availability) and of Extended Summer DR that would be consistent with the maintenance of reliability.[24] PJM based these targets directly on the limits on the obligations of these resources to respond to PJM's call for load reductions. Given that

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19 *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066, at P 3, *order on compliance filing and reh'g*, 135 FERC ¶ 61,102 (2011).

20 *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066, at P 27.

21 Limited DR is available only from June through September of each Delivery Year, and must be available for at least ten interruptions during that period, for at least six hours in duration between the hours of 12:00 p.m. to 8:00 p.m. Eastern Prevailing Time. RAA, section 1.43A.

22 Extended Summer DR is available only June, July, August, September, October, and May of each Delivery Year, for an unlimited number of interruptions, for at least ten hours in duration between the hours of10:00 a.m. to 10:00 p.m. Eastern Prevailing Time. RAA, section 1.20C.

23 Annual DR must be available for interruptions throughout the entire Delivery Year, for at least ten hours in duration, between the hours of 10:00 a.m. to 10:00 p.m. Eastern Prevailing Time for the months of June, July, August, September, October, and May and from 6:00 a.m. to 9:00 p.m. Eastern Prevailing Time for the months of November through April. RAA, section 1.1A.

24 *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066, at P 69, *order on compliance filing and reh'g*, 135 FERC ¶ 61,102, at P 24 (accepting compliance filing placing the methodologies for establishing the reliability target values in the Tariff); *see also PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,076 (accepting an additional, third test for determining the reliability target level of Limited DR).

these limited resources displace Annual Resources, generally speaking, these tests assess at what Demand Resource commitment quantity PJM will face a risk that it will need to call on resources for more than six hours, or for more than ten times in a summer, or during the winter months, but would have available only resources that are *not required* to respond to PJM under those conditions.[25] In short, these reliability targets directly measure the reliability risks that are inherent in the limitations that define these products.

Various parties objected to these tests when they were proposed in 2011, and when an additional test was proposed earlier this year, but in every instance the Commission rejected the protests and found that the tests used to set the reliability targets properly measured the reliability risks of these limited products.[26]

C. The Specific Method PJM Chose to Implement the Acknowledged Reliability Limits on the Lower-Quality Products Was Ill-Conceived, Because It Obstructs PJM's (and the Commission's) Intent that the Value of Annual Resources Would Be Properly Recognized.

PJM did not, however, propose to cap Limited DR or Extended Summer DR at these reliability target levels. Instead, PJM proposed to *subtract* these reliability target levels from the overall reliability requirement for all resources, and apply the result as a minimum requirement for the less-limited Annual Resources.[27] In other words, rather than putting a ceiling on the more-limited products, PJM put a floor under the less-limited products.

PJM proposed that if the RPM Auction is not clearing enough Annual Resources to satisfy the minimum requirement for Annual Resources, then prices would "separate" for the different products, and the auction would clear higher-priced Annual Resources as needed to meet the minimum requirement for those resources.[28]

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25 *See* Tariff, Attachment DD, sections 2.24C (defining and setting forth the methodology for determining the Extended Summer DR Reliability Target) and 2.36B (defining and setting forth the methodology for determining the Limited DR Reliability Target); *see also PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066, at PP 56-63, 69.

26 *See PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,076; *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066.

27 *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066, at PP 29-30. PJM proposed a similar rule to enforce the recognized reliability limit on Limited DR, i.e., rather than capping Limited DR, PJM set a minimum requirement for the sum of Annual Resources and Extended Summer DR. *Id.*

28 *Id*. at P 30 ("[w]hen additional quantities of the less-limited demand resources are required to meet the minimum resource requirements, prices can separate according to a resource's availability and overall contribution to system

(continued…)

PJM analogized its proposal to the locational constraints in RPM.[29] In one very important respect, however, that analogy was flawed. When a locational constraint "binds" in the auction, e.g., a Capacity Emergency Transfer Limit ("CETL") established for a Locational Deliverability Area ("LDA") is encountered, then not only do prices separate as between resources inside and outside that LDA, but *no more resources outside that LDA are permitted to clear to serve loads inside that LDA*. The CETL is accepted as a hard limit, based on reliability analysis, on the maximum quantity of outside generation that should be counted on to serve loads inside the LDA. By contrast, under PJM's proposal for the differing capacity product types, when the Minimum Annual Resource ("MAR") Requirement binds, prices will rise as needed to clear higher-cost Annual Resources up to the MAR Requirement, but the auction also will continue to clear the more-limited resources. And, once the MAR Requirement is satisfied, the auction-clearing algorithm loses any rationale to continue committing Annual Resources, because it then becomes free to commit lower-priced, and more restricted, products like Limited DR.

PJM has cleared three BRAs under these rules and has found that, indeed, whenever a minimum resource requirement triggers price separation, and that minimum requirement is then satisfied, the resources which cleared *beyond that point* and up to the sloped demand curve, generally are the more limited products. This happens for both the MAR Requirement and the Minimum Extended Summer Resource ("MESR") Requirement (which, as discussed above, is a minimum requirement for the combination of both Extended Summer and Annual Resources). Thus, even if Annual Resources do not encounter a vertical curve at the MAR Requirement, they may still face a vertical curve at the MESR Requirement. The need to meet *either* of these requirements can assign a price premium to Annual Resources, leading to a likelihood that lower-priced, lower-availability products will preferentially clear (and Annual Resources will no longer clear) once the relevant minimum requirement is met. Moreover, even when prices do not separate for any product, any offers from lower-availability resources that clear between the relevant Reliability Target and the sloped curve will displace Annual Resources and produce a clearing price that does not reflect the marginal costs of sufficient Annual Resources, i.e., the only resources available year-round, that the PJM Region needs for long-term reliability.

(…continued)

operations."). Again, PJM proposed a similar rule for Extended Summer Resources, allowing them to price-separate from Limited DR as needed to meet the minimum requirement for the sum of Extended Summer DR and Annual Resources (i.e., the Minimum Extended Summer Resource Requirement).

[29] Tariff and RAA Revisions Regarding Demand Response Saturation, Docket No. ER11-2288, at 29-31 (Dec. 2, 2010).

1. Under the current rules, price separation establishes a vertical demand curve at the relevant minimum resource requirement, and thus obstructs Annual Resource offers from reaching the sloped curve.

The current market rules are designed to enable price separation among the various types of capacity resources — Annual Resources (including Annual DR), Extended Summer DR, and Limited DR — so that the market can signal that the higher-priced products are valued over the lesser-priced products. Such price separation is driven by the need to meet the minimum resource requirements implemented to incorporate the three types of Demand Resources into RPM.

However, by setting a fixed minimum requirement for Annual Resources, PJM has in effect established a vertical demand curve for Annual Resources, the resource which provides the greatest reliability value. When prices separate, and Annual Resources are by definition more expensive than the more-limited products, then satisfaction of the MAR Requirement means the less-limited products will clear to the exclusion of the higher-priced Annual Resources. The same will occur when the minimum requirement for the combination of Annual Resources and Extended Summer DR binds (i.e., the MESR Requirement).[30] In that case, the auction will clear the Extended Summer DR and/or Annual Resources up to the minimum requirements, but then shift to the lower-priced Limited DR. In other words, the two fixed minimum requirements for Annual Resources and Extended Summer DR products have established two intermediate vertical curves for these products to the left of the sloped curve, with the result that Limited DR will often be the final increment of the supply base to interact with the sloped demand curve approved by the Commission seven years ago. This is illustrated in Figure 1 below:

[30] *See* Tariff, Attachment DD, section 2.41E.

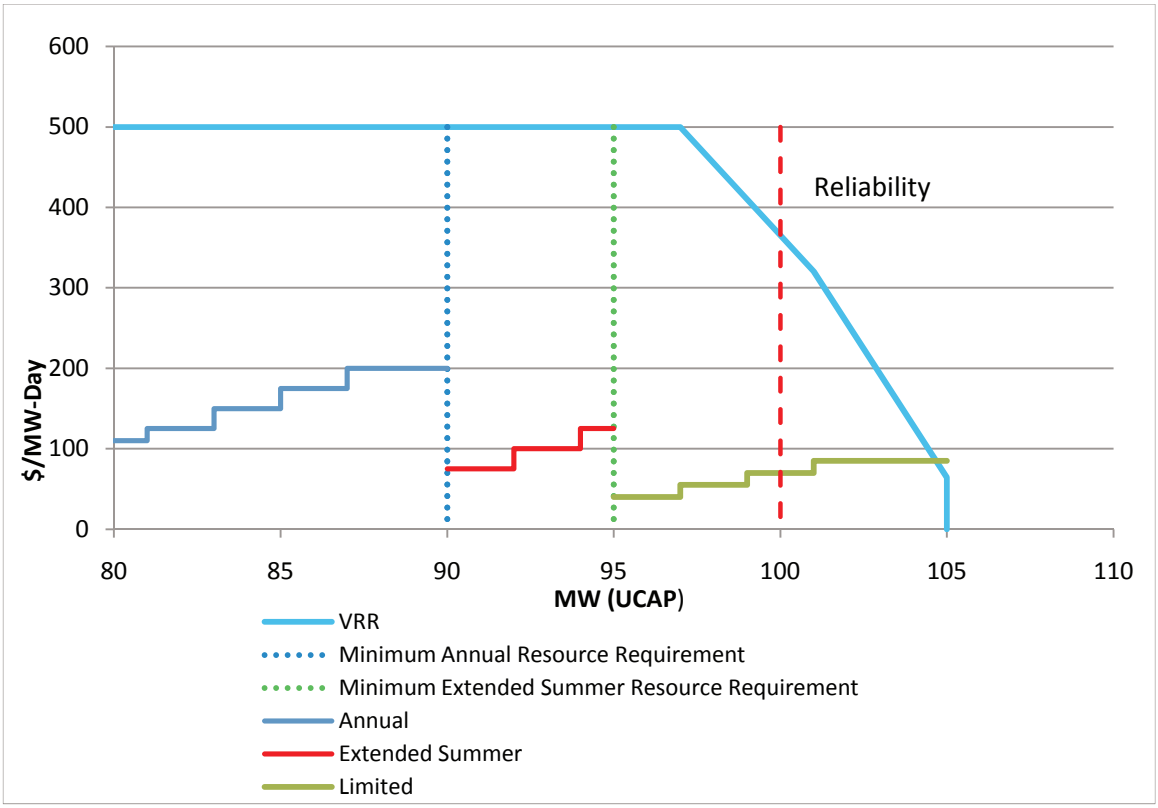

Figure 1 – PJM's Current Capacity Resource Clearing Process

Figure 1 illustrates a scenario in which both minimum requirements bind and all three products price-separate. Annual Resources clear with rising prices to the MAR Requirement. But the price separation, and satisfaction of the MAR Requirement, impels the auction algorithm to clear the lower-availability products, resulting in a price drop. Because the MESR Requirement also binds, Extended Summer DR clear with rising prices to the MESR Requirement, but the auction algorithm then seeks the lower-priced product—Limited DR—as soon as the MESR Requirement is satisfied, resulting in another price drop along the curve.[31] Limited DR then clears, with rising prices, until the intersection with the sloped demand curve.

This concern is not hypothetical. Recent BRA results plainly show the vertical curve in operation, capping the Annual Resource prices and clearing lower-priced Limited DR to the point of intersection with the sloped demand curve. As can be seen in Figure 2 below, the MAR Requirement did not bind in the 2015/2016 BRA, but the MESR Requirement did. Prices for Annual Resources and Extended Summer DR

[31] PJM notes that this scenario indicates that the current rules can result in a downward sloping *supply* curve, a highly anomalous result in a capacity market, where one would expect the marginal costs of each successive cleared resource to *increase*, not *decrease*.

therefore separated from the price for Limited DR. What happened next is a textbook illustration of the principles discussed above. The MESR Requirement was 155,315 MW. The sum of Annual Resources and Extended Summer DR that cleared was exactly that—155,315 MW. The clearing price for Annual Resources and Extended Summer DR was set at the single capacity level of the MESR Requirement, i.e., the vertical curve well to the left of the sloped curve. Beyond the MESR Requirement, *only Limited DR cleared*, and Limited DR offers intersected the sloped demand curve. But they did so at a price ($118.54/MW-day) well below the clearing price for Annual Resources and Extended Summer DR ($136/MW-day) that was set by the vertical curve. As can be seen, Limited DR offers effectively "blocked" Annual Resource offers from reaching the sloped demand curve. Had they not been blocked, Annual Resource offers would have continued, at rising marginal cost, until they reached the demand curve at a price somewhere above $136/MW-day, probably well above. Instead, the supply curve cleared at a *lower* price than had been set when *fewer* resources were cleared. The result is that these clearing prices do not reflect the marginal costs of all of the Annual Resources that the PJM Region will need on an ongoing basis to help assure reliability.

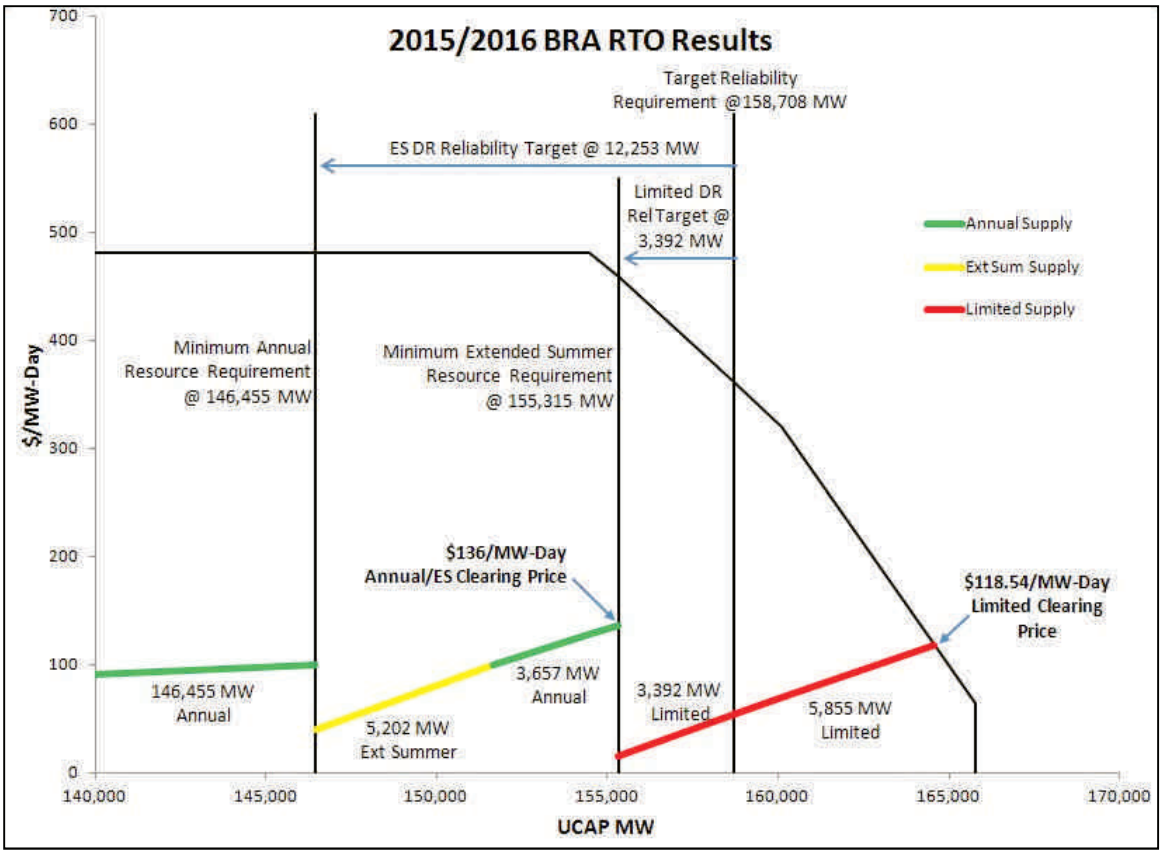

Figure 2 – 2015/2016 BRA Results Under Capacity Resource Clearing Process

This is decidedly not how the sloped demand curve was intended to operate. Annual Resources, without the seasonal, frequency, or duration limits of Limited DR and Extended Summer DR, and representing approximately 90% of the PJM Region capacity

resource base, are critical to the reliability of the PJM Region and *must* be properly valued. As shown, to realize the sloped curve's benefits of greater assurance of reliability at lower long-run cost, the curve must recognize the value of Annual Resources beyond the installed reserve margin. But when the curve selects lower-priced Limited DR or Extended Summer DR because the MAR Requirement has already been satisfied, then it is *not* valuing from a reliability perspective, Annual Resources beyond the established reserve margin (indeed, it is not valuing Annual Resources beyond the MAR Requirement). More importantly, the products with limited reliability value are displacing the annual products with greater reliability value. This has a long term impact of discouraging investment *both* in new generation and new annual demand response technologies and leaves PJM with a portfolio of resources that is less flexible in meeting capacity emergencies.

That, in a nutshell, is the problem created by one errant choice, in one technical clearing detail, nearly three years ago. The deficiencies in this rule are now readily apparent, and it must be corrected. Even if this problem arose only when prices separated, that would be reason enough to change it. The only reason to define distinct products *for purposes of a capacity market*, is to enable those distinct products to realize different prices *in the capacity market*. If the current rules on product price separation fail to work properly whenever prices separate, then it clearly is time for a correction.

2. Even when prices do not separate, more-limited and lower-valued capacity resources displace Annual Resources and prevent Annual Resources from interacting with the sloped demand curve.

But the problems are not limited to cases of price separation. PJM has found a similar result when there is *no* price separation. Over-procurement of the more limited products, whether or not price separation occurs, implies that the BRAs may not be sending a valid price signal about the value or need for Annual Resources versus Limited DR and Extended Summer DR.

For example, in the BRA for the 2016/2017 Delivery Year prices did not separate among the three types of demand resource products in the bulk of the PJM Region.[32] However, Limited DR cleared *thousands of megawatts* above its minimum target,[33]

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[32] *See* 2016/2017 RPM Base Residual Auction Results, at 1 (stating that the RTO price for Annual Resources, Extended Summer DR, and Limited DR was $59.37 per MW-day), http://www.pjm.com/sitecore%20modules/web/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-base-residual-auction-report.ashx.

[33] Indeed, 6,387.4 MW of Limited DR cleared above the 2016/2017 BRA Limited DR Reliability Target of 3,462.1 MW. *Compare* 2016/2017 RPM Base Residual Auction Results, at 10, Table 3B (9,849.5 MW of Limited DR cleared), *with* 2016/2017 RPM Base Residual Auction Planning Parameters (Limited DR Reliability Target of 7,615.3 MW less the Short-Term Resource Procurement Target of 4,153.2 MW equals 3,462.1 MW), (continued…)

resulting in displacement of other, higher-valued products including Generation Capacity Resources and Annual DR. There should have been price separation in that BRA because the higher-availability Annual Resources and Extended Summer DR products should have been committed in lieu of the lower-value Limited DR because Limited DR had already reached its reliability target quantity. Committing higher valued resources in response to Limited DR meeting its reliability target would have resulted in a more appropriate, higher clearing price for the higher-valued products, thereby providing the correct and necessary, long-term, stable price signals that will stimulate investment, particularly in Annual Resources. However, no price separation occurred because the lower-availability Limited DR were allowed to clear in excess of their reliability target, thereby displacing the higher-availability products and suppressing the long-term price signal that is crucial for stimulating necessary investment in Annual Resources.

This problem is exacerbated by the manner in which the RPM algorithm clears "coupled" Demand Resource offers, e.g., where a resource offers a quantity of Limited DR at one price and a quantity of Extended DR at a higher price. The RPM algorithm examines the coupled offers against the market needs and selects the least-cost option that also provides the greatest profit margin to the offering resource. In this way, almost all coupled offers end up clearing as Limited DR, even though Annual and Extended Summer DR provide greater reliability benefit to PJM. For example, in the BRA for the 2016/2017 Delivery Year, *no* Annual DR submitted as part of a coupled offer cleared. And of the cleared coupled offers, only 676.5 megawatts (or 13 percent) were cleared as Extended Summer DR, while 5,182.1 megawatts cleared as Limited DR.[34]

Based on the foregoing, while price separation scenarios provide the most dramatic evidence of the problem in the current rules, which allow more-limited and lower-valued capacity resources to displace Annual Resources and prevent Annual Resources from interacting with the sloped demand curve, the data clearly indicates that the problem exists today even without price separation. Any time the Limited DR and/or Extended Summer DR products clear in excess of their respective reliability targets, by definition that excess is displacing Annual Resources that would have otherwise cleared up to the sloped demand curve. By reducing the Annual Resource quantities that intersect the sloped demand curve, the current mechanism is suppressing Annual Resource prices, and denying the PJM Region the reliability and efficiency benefits that a sloped demand curve was intended to provide.

(…continued)
http://www.pjm.com/~/media/markets-ops/rpm/rpm-auction-info/2016-2017-planning-period-parameters.ashx.

[34] *See* 2016/2017 RPM Base Residual Auction Results at 10, Table 3B.

III. THE CURRENT RULES CAN SIGNIFICANTLY INTERFERE WITH THE LONG-TERM RELIABILITY UNDERPINNINGS OF RPM, AND MUST BE CORRECTED

A. The Current Rules Effectively Establish A Vertical Demand Curve For Annual Resources.

Given the concern that certain RPM market changes implemented in 2011 might be blunting the effects of the downward sloped curve for Annual Resources, PJM retained Professor Hobbs to address (1) whether those rule changes, including setting a minimum requirement for Annual Resources, have effectively subjected the clearing of those resources to a vertical demand curve; and (2) the likely effects of such a vertical demand curve (compared to a sloped curve) on the resource adequacy performance and cost of the RPM market's procurement of Annual Resources. Professor Hobbs' affidavit setting forth the results of his analysis of these two issues is included as Attachment A to this filing.

On the first question, Professor Hobbs concludes that "[t]he imposition of a fixed MAR [] Requirement, together with a large quantity of lower priced offers of demand resource with limited availability, has resulted in an effective demand curve for Annual Resources that is vertical."[35] He explains that as a result of these recent rule changes, "Annual Resources have lost the price stabilization, reliability and consumer cost benefits of the sloped demand curve that I described in my 2005 and 2006 RPM affidavits."[36]

Elaborating on these points, Professor Hobbs explains that, currently, as long as the auction procures enough Annual Resources to meet the MAR Requirement, and enough Annual Resources combined with Extended Summer DR to meet the MESR Requirement, "any procured capacity in excess of those requirements up to the intersection with the sloped demand curve can be provided entirely by the Demand Resources with limited availability."[37] This will happen whenever "the more limited DR are offered at a lower price than offers from incremental quantities of Annual Resources or Extended Summer DR that are in excess of the minimum requirements."[38]

The result, Professor Hobbs explains, is that "Annual Resources offered are, in effect, cleared against a vertical demand curve defined by the MAR requirement;" and, even more significantly, "*the sloped demand curve beyond the MAR requirement has no impact on the cleared quantities and clearing prices of the Annual Resources*."[39] In

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35 Affidavit of Professor Benjamin L. Hobbs (Attachment A) ¶ 10 ("2013 Hobbs Affidavit").

36 *Id.*

37 *Id.* ¶ 14.

38 *Id.*

39 2013 Hobbs Affidavit ¶ 15 (emphasis added).

short, "the price received by Annual Resources is determined by the intersection of their overall offer (supply) curve with the MAR requirement, which, as a fixed quantity, acts as a vertical demand curve with a price cap." Consequently, "the long-run reliability and cost benefits provided by a sloped demand curve relative to a vertical demand curve are, in effect, unavailable to the capacity resource type having no seasonal or response limitations and highest reliability value (i.e., Annual Resources)." Instead, those benefits are "maintained for capacity resource types having the lowest availability and response requirements and lowest reliability value (i.e., Limited DR and Extended Summer DR)."[40]

Professor Hobbs recommends, therefore, that "[t]o restore those benefits for Annual Resources, which have the highest level of reliability due to their absence of seasonal or response limitations, a slope can be introduced in their effective demand curve."

B. Allowing A Vertical Curve To Govern Procurement Of Annual Resources Will Substantially Degrade The Likelihood That The PJM Region Will Meet Resource Adequacy Objectives, And Will Increase Costs To Consumers.

At PJM's request, Professor Hobbs then applied a version of the dynamic capacity market model used in his 2005-2006 work on RPM to analyze the potential long-run benefits of restoring the slope to the effective demand curve that Annual Resources face. One key difference from his earlier work, however, is that the "target annual capacity" (i.e., the resource procurement goal in his model) is no longer the level set by PJM's Installed Reserve Margin as it was in his original analyses, but rather the lower level set by the MAR Requirement, as that is the "vertical curve" at issue here.[41]

Professor Hobbs uses the latest data available (principally that used in the most recent BRA) and the same reliability and cost parameters that he used in his affidavits supporting RPM and the current RPM sloped demand curve.[42] Professor Hobbs details the key assumptions and input parameters used in his analysis.[43]

Based on his analysis, Professor Hobbs concludes that the sloped curve "robustly outperforms the vertical demand implied by the MAR requirement, in terms of generally

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40 *Id.*

41 Employing data used in the most recent BRA, for example, the PJM Region Reliability Requirement for Unforced Capacity (reflecting both the Installed Reserve Margin and demand-equivalent forced outage rate) is 109 percent of peak load, while the MAR Requirement (which deducts the Extended Summer Reliability Target of 10.9 percent) is 98.1 percent of peak load. *See id.* ¶ 22.

42 *See* 2013 Hobbs Affidavit ¶ 11.

43 *Id.* ¶¶ 18, 20, 22.

having a higher probability of installed annual capacity meeting the requirement and lower consumer costs."[44]

Specifically, Professor Hobbs found that, when using a vertical demand curve (as is the case under the current rules), PJM would meet or exceed the MAR Requirement only 42 percent of the time. By contrast, when using a sloped demand curve (i.e., restoring the interaction between Annual Resources and PJM's existing sloped demand curve), the MAR Requirement is met or exceeded 96 percent of the time.[45] His model also measured the average amount of reserves relative to the target annual capacity, and found that with the vertical curve annual capacity would *fall below* the MAR Requirement by 0.62 percent. By contrast, with the sloped demand curve, the MAR Requirement would on average be *exceeded* by 1.24 percent. Professor Hobbs also found that the revenue required by risk-averse generators, the profit for a new entry peaking plant, and the cost to consumers, all are lower for the sloped curve than for the vertical curve, and that the revenues and profits also are less variable under the sloped curve.[46]

To further test his conclusions, Professor Hobbs ran numerous sensitivity cases, revising various material modeling assumptions, such as the price of supply offers into the auction, the degree to which investors are risk-averse, and the level of load forecast uncertainty. While he found that changes in the assumptions "did change the quantitative level of performance (capacity adequacy, generator revenues and profits, and consumer costs) of the capacity market," the sloped curve "still robustly outperforms the vertical demand curve in all cases on both reliability indices, as well as consumer costs."[47] He further found that "[t]he precise degree to which the sloped curve is superior depends on the assumptions, as would be expected, but the vertical curve is never better."[48]

C. Clearing Even Higher Levels Of The More-Limited Products, In Lieu Of Committing Annual Resources, Therefore Raises Long-Term Reliability Issues.

In addition to the reliability risks described by Professor Hobbs, the current rules pose other reliability concerns. All of these risks arise from the obvious fact that a resource that has substantial limits on its obligation to provide load reductions is not a cost-free substitute for a resource that does not have those limits. Indeed, each megawatt procured of more-limited resources displaces Annual Resources and sends the incorrect price signal to the market. The incorrect price signals, in turn, lead Annual Resources,

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44 *Id.* ¶ 11.

45 *Id.* ¶ 24.

46 2013 Hobbs Affidavit ¶ 29.

47 *Id.*

48 *Id.*

e.g., generation resources, to retire prematurely and dissuade investors from developing new Annual Resources.

As Professor Hobbs explained, a basic premise of the sloped demand curve is that it values capacity resources in excess of the reserve margin and under the slope of the demand curve, which is a principle that the Commission found to "provide additional reliability benefits, which is reflected in the positive prices in the sloped demand curve to the right of IRM" and which "is not reflected in the current [vertical demand curve] construct."[49] These prices act as a forward investment signal for long term resources and inaccurate price signals may cause such resources to cancel or defer their development plans.

However, since the minimum resource requirements were put in place in 2011, PJM has realized that there is a long-term reliability detriment when the committed amounts of Limited DR and Extended Summer DR exceed their reliability targets. Such over-procurement of more-limited resources suppresses prices for the higher valued Annual Resources — including both Annual DR and Generation Capacity Resources — by preventing Annual Resources from interacting with the sloped demand curve and sending the appropriate price signals to the market. As explained above, this harm occurs even in the absence of price separation.

IV. STAKEHOLDER PROCESS

The PJM market reforms in this filing were developed through a stakeholder process commencing in May 2013 at the Capacity Senior Task Force ("CSTF"). As the stakeholder process unfolded throughout 2013, the above-described reliability concerns were presented by PJM at the CSTF, the PJM Markets and Reliability Committee ("MRC"), and the PJM Members Committee ("MC").

During the nearly six-month stakeholder process, PJM received valuable input that has significantly shaped this filing. Outside experts were also brought in to facilitate an examination of the issues and develop potential solutions. The stakeholder process also allowed PJM to delve deeply into the reliability impacts of clearing Limited and Extended Summer DR in excess of their reliability target levels and to find that such excess amounts *do* pose a reliability concern.

Through the stakeholder process, PJM and other parties developed proposals to resolve these issues. However, none of these proposals received supermajority support at the CSTF, MRC, or MC. Thus, the PJM Board of Managers ("PJM Board") exercised its independent authority[50] and directed PJM to submit the enclosed Tariff and RAA changes under section 205 of the Federal Power Act. These RPM market reforms are concerned

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49 *RPM Settlement Order* at P 104 (2006).

50 Tariff, section 9.2(a) (authorizing PJM Board to make changes); RAA, section 16.4 (same).

with preserving the reliability of the PJM Region, which is a core responsibility of the PJM Board.[51]

V. ENCLOSED TARIFF REVISIONS

A. PJM Is Retiring The Minimum Annual And Extended Summer Resource Requirements And Adding Sub-Annual And Limited Resource Constraints.

As discussed above, the current problem stems from PJM's choice three years ago to set a floor under the higher-availability products instead of putting a ceiling on the lower-availability products. The solution, therefore, is relatively straightforward—eliminate the floors and introduce ceilings.

Accordingly, beginning with the 2017-2018 Delivery Year that is the subject of the next BRA (scheduled for May 2014), the RPM Auctions will no longer include a MAR Requirement or a MESR Requirement. Instead, the auctions for the 2017-2018 and subsequent Delivery Years will employ a Limited Resource Constraint and a Sub-Annual Resource Constraint. The Limited Resource Constraint, as its name implies, will apply to Limited DR. The Sub-Annual Resource Constraint will apply to the sum of Limited DR and Extended Summer DR.

Both of these constraints will rely on the Reliability Targets that the Commission already has approved for Limited and Extended Summer DR. The Commission has found that these reliability targets set the maximum amounts that can count towards the IRM with "an acceptable level of risk,"[52] and, for Limited DR, "minimize the risk of potential reliability concerns from relying on a resource that is not required to respond after six hours of interruption."[53] Thus, the Commission-accepted Reliability Targets appropriately define the quantities of the more-limited resources that can be procured without negatively affecting reliability. An adjustment is needed, however, to properly reflect the Short-Term Resource Procurement Target ("STRPT"), i.e., the 2.5 percent of the total reliability requirement that PJM "holds back" from the BRA.[54] The Commission established the STRPT specifically to allow short lead time resources like Limited DR to provide capacity through the Incremental Auctions.[55] Currently, PJM subtracts the

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51 Operating Agreement, section 7.7(vi)

52 *PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,066, at P 74.

53 *PJM Interconnection, L.L.C.*, 143 FERC ¶ 61,076, at P 34.

54 Tariff, Attachment DD, proposed section 2.36C.

55 *PJM Interconnection, L.L.C.*, 126 FERC ¶ 61,275, at P 83 (the 2.5 percent holdback "provide[s] for the participation of demand response resources in the incremental auctions, in addition to the Base Residual Auction, by setting a short-term resource procurement target of 2.5 percent to be procured in the three

(continued…)

STRPT from the overall Reliability Requirement, but does not subtract it from either the MAR Requirement or the MESR Requirement. The net effect is to reduce, by the STRPT, the procurement of Limited DR sought in the BRA. This is consistent with the Commission's recent decision to *not subtract* the STRPT from the MAR Requirement or the MESR Requirement to "make[] certain that the hold-back serves the purpose in the capacity auctions for which it was originally intended."[56] The Commission found that not subtracting the 2.5 percent holdback from the minimum resource requirements "strikes an appropriate balance between providing an opportunity for short lead-time resources to participate in the incremental auctions and send adequate investment signals to long lead-time resources."[57]

The analogy to *not subtracting* the STRPT *from the floors* (under the current rules) is to *subtract* them from the *ceilings* (under the proposed rules). Thus, PJM is proposing to subtract the 2.5 percent holdback from each of the Limited and Sub-Annual Resource Constraints to ensure that these short lead-time resources will have the opportunity to participate in the incremental auctions without affecting system reliability.

In short, PJM proposes a Sub-Annual Resource Constraint to limit the total amount of capacity that can be committed as either Extended Summer DR or Limited DR for each Delivery Year[58] and that equals the Sub-Annual Resource Reliability Target[59] less the STRPT. Similarly, PJM proposes a Limited Resource Constraint to limit the quantity of Limited DR that can be cleared in the auctions, which is equal to the Limited DR Reliability Target less the Short Term Resource Procurement Target.

These constraints will now operate like PJM's locational constraints. In other words, just as a locational constraint stops procuring any capacity located outside a constrained LDA to serve load in that LDA after the constraint binds, triggering of these resource constraints means that the auction algorithm will stop procuring these resource types to serve PJM load.

(…continued)

incremental auctions"), *modified*, 127 FERC ¶ 61,036, *order on clarification*, 127 FERC ¶ 61,104, *order on reh'g*, 128 FERC ¶ 61,157 (2009).

56 *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,062, at P 121 (2012).

57 *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,062, at P 117.

58 Tariff, Attachment DD, proposed section 2.25.

59 PJM is proposing to rename the Extended Summer DR Reliability Target as the "Sub-Annual Resource Reliability Target," because the Extended Summer DR Reliability Target incorporates the Limited DR Reliability Target amount and measures the amount of Extended Summer DR plus the amount of Limited DR that can clear without hampering reliability. PJM is also making conforming changes to ensure that tariff references the Sub-Annual Resource Reliability Target, where appropriate. *See* Tariff, Attachment DD, proposed section 2.24C.

The adoption of these two resource constraints while simultaneously retiring the MAR and MESR Requirements allows Annual Resources to be the resources that clear in excess of the reserve margin up to the sloped demand curve. The figure below illustrates how resources may clear under this new process.

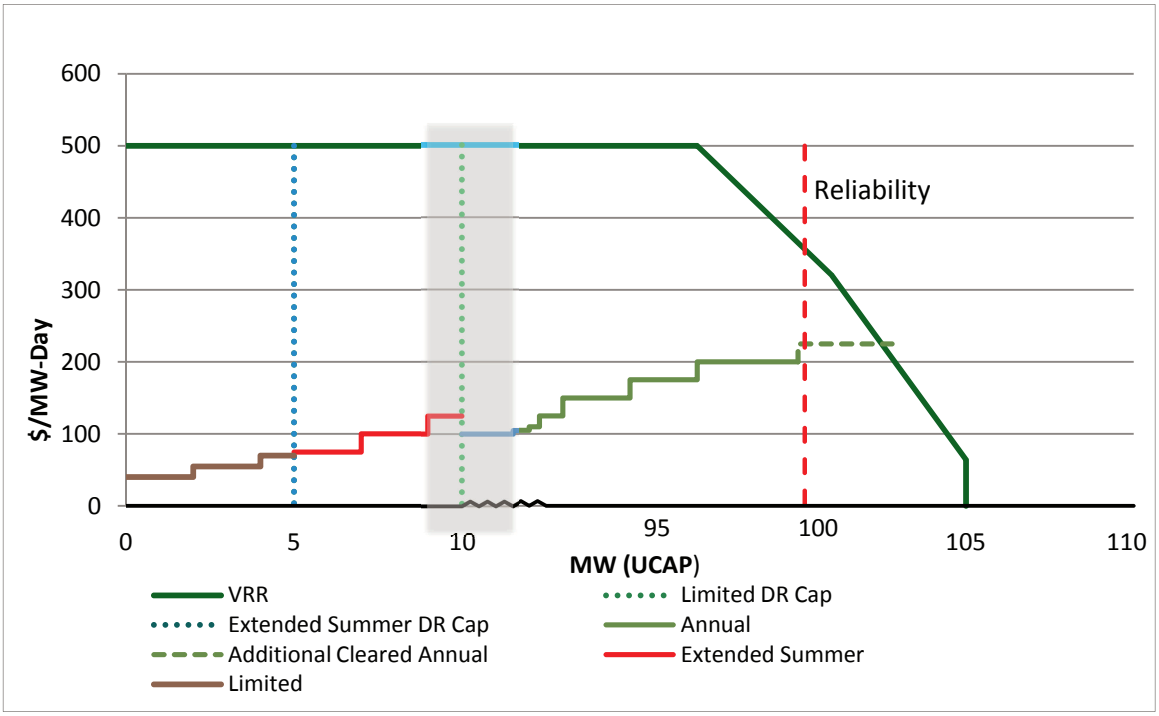

Figure 3 – RPM Clearing of Capacity Resources Under Proposed RPM Market Reforms

These RPM market reforms ensure that the capacity procured above the reserve margin is of a type that provides the greatest incremental reliability benefit and restores the sloped portion of the demand curve for this capacity. Indeed, a comparison of Figure 3 and Figure 1 demonstrates that Annual Resources will displace Limited DR as the resources clear in excess of the reserve margin.

Moreover, as shown in Figure 4 below, PJM's simulation demonstrates that, had these rule changes been in effect for 2015/2016 BRA, Annual Resources would have intersected with the sloped demand curve and cleared at $143.53 per MW-day. By contrast, in the actual 2015/2016 BRA, as shown in Figure 2 above, only Limited DR intersected with the sloped demand curve and cleared at $118.54 per MW-day.

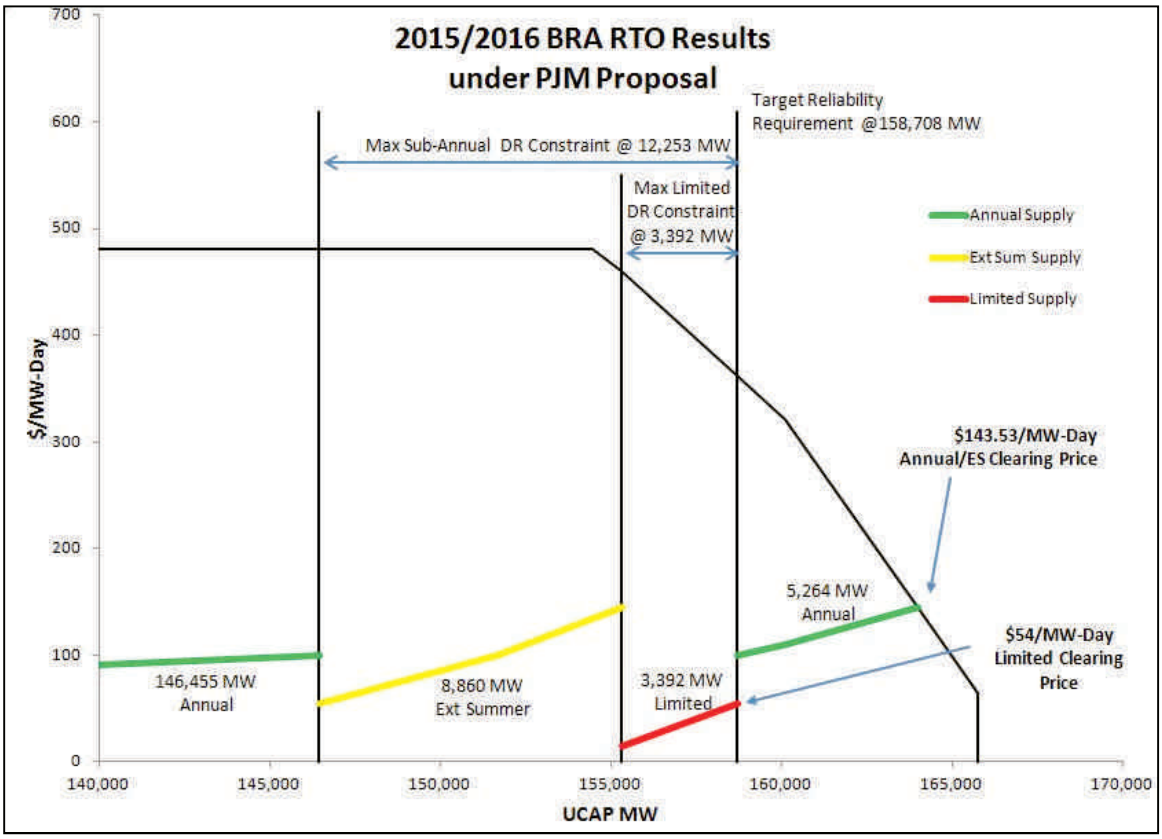

Figure 4 – 2015/2016 BRA Simulated Results Under Changes Proposed In This Filing

Accordingly, Annual Resources will now send the proper price signals to investors and induce greater long-term investment in the resources that provide the greatest reliability benefit.

To effectuate these changes, PJM is revising Tariff, Attachment DD, sections 3.2, 5.10(c), 5.11(a)(vi), 5.12(a), 5.12(b), and 5.12(b)(v) to state explicitly that for the Delivery Years starting June 1, 2014 and ending May 31, 2017, PJM will continue to use the minimum resource requirements, however, for the Delivery Year starting June 1, 2017, and subsequent Delivery Years, PJM will establish the Limited and Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area that PJM is required to establish a separate VRR Curve.

B. The Change In The Process For Clearing Capacity Products Requires A Conforming Change In the Tariff's Description of Product Price Separation.

The change from floors on the higher-availability products to ceilings on the lower-availability products requires a conforming change to the Tariff's description of product price separation. The current Tariff envisions that the "base" price of capacity will be, in effect, the cost of Limited DR, and all other product prices are calculated through "adders" (i.e., adders for higher-valued products, and/or adders for higher-valued

locations) to that base price.[60] To effectuate the present proposal, PJM needs to set the Annual Resource price as the "base" price. Locational price adders, for example, will be calculated as additions to the "base" Annual Resource price. Similarly, price differences for the lower-availability products (which will be less than the Annual Resource price whenever prices separate) need to be accounted for through decremental adjustments to the Annual Resource price. Notably, this conforming change is simply a mathematical consequence of implementing ceilings on the two lower-availability products. When those constraints bind, they "move" the price of the affected resources, and specifically they move it relative to the only product that is not subject to constraints, i.e, Annual Resources. This treatment is comparable to the approach today, in which the minimums on Annual Resources and Extended Summer DR "move" the price of the products to which they apply, and move them relative to the one category that is not subject to any constraints, i.e., Limited DR.

Specifically, PJM is proposing the Limited Resource Price Decrement and the Sub-Annual Resource Price Decrement. The Limited Resource Price Decrement simply equals the difference between the clearing price for Limited DR and the clearing price for Extended Summer DR and Annual Resources and represents the cost to procure additional Annual Resources or Extended Summer DR out of merit order when the Limited Resource Constraint is binding.[61] Similarly, the Sub-Annual Resource Price Decrement simply equals the difference between the clearing prices for Extended Summer DR and Annual Resources and represents the cost to procure additional Annual Resources out-of-merit order when the Sub-Annual Resource Constraint is binding.[62]

C. PJM Is Proposing To Transition To This New RPM Clearing Process Starting With The May 2014 BRA For The 2017/2018 Delivery Year And Maintain the Current Process For The Interim Delivery Years.

PJM is proposing to implement these RPM reforms starting with the BRA to be held in May 2014 for the 2017/2018 Delivery Year so as not to affect the process by which capacity resources have already been committed in BRAs and Incremental Auctions for the 2014/2015 and 2016/2017 Delivery Years. Accordingly, PJM is making several revisions to clarify that the current process will be in place through the 2016/2017 Delivery Year. For example, the definitions of Minimum Annual and Extended Summer Resource Requirements and Annual and Extended Summer Resource Price Adders now specify that they apply only until the Delivery Year ending May 31, 2017. In addition, PJM is modifying the definitions of the Limited and Extended Summer DR Reliability Targets to clarify that the targets will only be used to calculate these minimum resource

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60 Tariff, Attachment DD, sections 2.1C (Annual Resource Price Adder), 2.24B (Extended Summer Resource Price Adder), and 5.14(a) (stating how capacity clearing prices are determined).

61 Tariff, Attachment DD, proposed section 2.36D.

62 Tariff, Attachment DD, proposed section 2.65C.

requirements for the Delivery Years through May 31, 2017. However, PJM is including language providing that the Limited and Extended Summer DR Reliability Targets will be used in determining the Sub-Annual and Limited Resource Constraints starting with the 2017/2018 Delivery Year.[63]

D. The New Capacity Resource Constraints Will Be Applied To FRR Capacity Plans Starting With The 2017/2018 Delivery Year.

The RAA provides an alternative method of capacity commitment, known as the Fixed Resource Requirement ("FRR"), which parallels RPM in many respects, including the use of the minimum resource requirements and the ability to meet capacity needs through Demand Resources. The reforms in this filing are also intended to apply to the FRR. Accordingly, PJM is revising RAA Schedule 8.1 that sets forth the FRR rules.

Specifically, PJM is revising sections D(2) and F(5) of RAA Schedule 8.1, regarding FRR Capacity Plans, to add the requirement that for the 2017/2018 Delivery Year and subsequent Delivery Years the set of capacity resources designated in each FRR Capacity Plan must be subject to the Limited and Sub-Annual Resource Constraints applicable to the FRR entity's capacity obligation. Consistent with the above-described transition, PJM is also modifying section D(2) to state that the current minimum resource requirements only apply to the 2016/2017 Delivery Year and prior Delivery Years.

E. DR Providers Can Continue To Provide Capacity Products And Accommodate The PJM Region's Need For Resources With Greater Availability.

The changes proposed in this filing will not affect the quantities of each capacity product that clear up to the target reliability requirement for the PJM Region. The sole difference between the new process and the current process is which resources clear *after* the region's target reliability requirement is met. This is evident from Figure 4 above which shows PJM's simulation of the 2015/2016 BRA as conducted under the rule changes proposed in this filing. Additionally, Figure 4 shows that the cleared Demand Resources tend to shift from lower-availability Limited Demand Resources to higher-availability Extended Summer Demand Resources, which also improves reliability in addition to bringing the sloped demand curve to Annual Resources.

PJM appreciates the value Demand Resources bring to the system and encourages Demand Resources to participate in RPM and serve the PJM Region's capacity needs. As the Commission has recognized, the current RPM market rules provide a number of ways for Demand Resources to participate and clear in RPM auctions.[64] First, the more-limited Demand Resources can compete with other resource types to provide capacity up

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63 *See* Tariff, Attachment DD, proposed sections 2.24C (Sub-Annual Resource Reliability Target) and 2.36B (Limited Demand Resource Reliability Target).

64 *See, e.g.*, *PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,062, at P 125 (2012).

to the new constraints. Second, a Limited DR resource that could also serve as an Annual or Extended Summer DR resource can submit a coupled offer to compete with resources of the same type and bypass the Limited or Sub-Annual Resource Constraints. Third, Limited DR can be aggregated to create a portfolio of resources that can be bid into the BRA as Annual or Extended Summer DR.

VI. EFFECTIVE DATE

The enclosed Tariff and RAA revisions reflect an effective date of January 31, 2014, i.e., 63 days after the date of this filing. PJM is scheduled to conduct its next RPM BRA in May 2014 and must post relevant parameters for that auction by February 1, 2014. The enclosed Tariff changes affect the parameters that PJM must post at that time. The requested effective date will allow PJM to reflect these revised parameters in that posting.

VII. CORRESPONDENCE

The following individuals are designated for inclusion on the official service list in this proceeding and for receipt of any communications regarding this filing:

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VIII. DOCUMENTS ENCLOSED

PJM encloses with this transmittal letter:

(1) Attachment A – Affidavit of Professor Benjamin L. Hobbs;

(2) Attachment B – redline version of the revised section to the electronic tariff; and

(3) Attachment C – clean version of the revised section to the electronic tariff.

IX. SERVICE

PJM has served a copy of this filing on all PJM members and on all state utility regulatory commissions in the PJM Region by posting this filing electronically. In accordance with the Commission's regulations,[65] PJM will post a copy of this filing to the FERC filings section of its internet site, located at the following link: http://www.pjm.com/documents/ferc-manuals/ferc-filings.aspx with a specific link to the newly-filed document, and will send an e-mail on the same date as this filing to all PJM members and all state utility regulatory commissions in the PJM Region[66] alerting them that this filing has been made by PJM and is available by following such link. If the document is not immediately available by using the referenced link, the document will be available through the referenced link within 24 hours of the filing. Also, a copy of this filing will be available on the Commission's eLibrary website located at the following link: http://www.ferc.gov/docs-filing/elibrary.asp in accordance with the Commission's regulations and Order No. 714.

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65 *See* 18 C.F.R. §§ 35.2(e), 385.2010(f)(3).

66 PJM already maintains, updates, and regularly uses e-mail lists for all PJM members and affected state commissions.

X. CONCLUSION

Accordingly, PJM requests that the Commission accept the enclosed Tariff and RAA revisions, effective January 31, 2014.

Respectfully submitted,

/s/ *Paul M. Flynn*

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November 29, 2013

Attachment A

Affidavit of Professor Hobbs

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.) Docket No. ER14-_____

AFFIDAVIT OF BENJAMIN F. HOBBS ON BEHALF OF PJM INTERCONNECTION, L.L.C.

1. My name is Benjamin F. Hobbs and I am the Theodore K. and Kay W. Schad Professor (and Chair) of Environmental Management and Professor of Applied Mathematics and Statistics (Joint Appointment) at the Johns Hopkins University located in Baltimore, Maryland. I am also the inaugural, Founding Director of the Johns Hopkins University Environment, Energy, Sustainability, & Health Institute established in 2010. My business address is 7107 Wardman Rd., Baltimore, Maryland 21212. I am submitting this affidavit on behalf of PJM Interconnection, L.L.C. ("PJM").

I. QUALIFICATIONS AND EXPERIENCE

2. I have been a member of the faculty of Johns Hopkins University's Department of Geography & Environmental Engineering since 1995, for which I have also served as chairman. I have also held a joint appointment in the Department of Applied Mathematics & Statistics since 1995. Previously to joining the Hopkins faculty, I was Economics Associate at Brookhaven National Laboratory, National Center for Analysis of Energy Systems (1977-1979). I then joined the Energy Division of Oak Ridge National Laboratory as a Wigner Fellow from 1982-1984. Between 1984 and 1995, I was on the faculty of the departments of Systems Engineering and Civil Engineering at Case Western Reserve University. While there, I was named a Presidential Young Investigator by the National Science Foundation.

3. I earned a Bachelor of Science degree in a self-designed program in environmental science and mathematics from South Dakota State University in 1976, and a Master of Science degree in Resource Management and Policy in 1978 from the College of Environmental Science & Forestry of the State University of New York. My Ph.D. was awarded in 1983 in Environmental Systems Engineering from Cornell University, with minors in Operations Research and Resource Economics.

4. My research and teaching concerns the application of systems analysis and economics to electric utility regulation, planning, and operations, as well as environmental and water resources systems. A particular focus of my research is the use of engineering-economy models to simulate electricity and emissions allowances markets, recognizing transmission and other technical constraints and imperfectly competitive behavior by market participants. My present research focuses on power market modeling, capacity market design, analysis of pollution policies under uncertainty and climate change, and decision analysis applications in ecological management. I have published three books and over 150 refereed papers on these topics. My work has

received best paper awards from several professional societies. I have on-going research projects sponsored by the National Science Foundation, the US Department of Energy Consortium for Electricity Reliability Technology Solutions, Minnesota Pollution Control Agency, and the National Institutes of Health.

5. I have had visiting appointments at the Helsinki University of Technology, University of Washington, and ECN (Netherlands Energy Research Center). In 2009-2010, I was an Overseas Fellow at Churchill College and a Senior Researcher at the Electricity Policy Research Group ("EPRG") at the University of Cambridge. I continue as a Research Associate of EPRG.

6. In the last ten years, I have been a consultant to Booz & Company, the UK Office of Gas & Electricity Markets, the Maryland Department of the Environment, the Louisiana Coastal Protection and Restoration Authority, Lawrence Berkeley Laboratory, FinGrid (Finnish Network Operator), the U.S. Army Corps of Engineers (Baltimore District), the Brattle Group, the U.S. Department of Energy (Energy Information Agency), and the Maryland Power Plant Research Program. My consulting has addressed a number of topics in power and water systems planning and market design. From 1996-2001, I was a consultant to the FERC Office of the Economic Advisor on market design and market power mitigation. I am on the editorial board of several journals in electric power engineering and economics. These include *Competition and Regulation in Network Industries*, *Economics of Energy & Environmental Policy*, *Energy Economics*, *EURO Journal on Decision Processes*, *Journal of Energy Markets*, *Journal of Energy Engineering (ASCE)*, *IEEE Transactions on Power Systems*, *Power Engineering Letters (IEEE)*, *Energy, The International Journal*, and *The Electricity Journal*. I served as Area Editor for Environment and Natural Resources for *Operations Research* between 1996 and 2005.

7. I am Chairman of the Market Surveillance Committee of the California Independent System Operator, which I have served as a member since 2002. I am also on the Public Interest Committee of the Gas Technology Institute. I am presently Scientific Advisor to the Policy Studies division of the Netherlands Energy Research Center. I was an Institute Associate of the National Regulatory Research Institute, Columbus, OH from 1989-1995. I hold the rank of Fellow in the Institute of Electrical and Electronics Engineers and the Institute for Operations Research and Management Science.

II. PURPOSE OF THIS AFFIDAVIT

8. I previously submitted an affidavit in connection with the August 31, 2005 filing by PJM before the Federal Energy Regulatory Commission ("FERC" or "Commission") to establish the Reliability Pricing Model ("RPM"), in Docket No. ER05-1410-000. I also submitted (1) a supplemental affidavit on May 30, 2006, in Docket Nos. ER05-1410-000 and EL05-148-000, in response to the Commission's April 20, 2006 order on the RPM proposal, addressing certain issues concerning the definition and analysis of alternative demand curves for capacity, and (2) another supplemental affidavit on September 29, 2006, for the purpose of presenting an analysis of the demand curve agreed upon by the parties in the settlement filed on September 29, 2006, and to discuss the adjustment of the

assumed Cost of New Entry ("CONE") in response to experienced capacity prices. Among other things, my prior affidavits compared vertical demand curves against downward sloping demand curves and found that the sloped demand curves better satisfied resource adequacy objectives and yielded lower average cost.

9. Earlier this year, PJM asked me to assess whether RPM market changes implemented in 2011 might be blunting the effects of the downward sloped demand curve for the largest class of capacity resources, *i.e.*, those available throughout the year (as distinct from certain resources that are available only four or six months of the year, and that have other limits on their required response). This affidavit, reflecting work I conducted and presented to PJM and PJM stakeholders in August and September of 2013, sets forth my analysis. Specifically, in this affidavit, I address (1) whether the 2011 rule changes, including setting a minimum requirement for capacity resources, available throughout the year ("Annual Resources"), have effectively subjected the clearing of those resources to a vertical demand curve; and (2) if so, what are the likely effects of that vertical demand curve on the resource adequacy performance and cost of the RPM market's procurement of those Annual Resources, compared to the performance and cost resulting from a sloped demand curve.

III. CONCLUSIONS

10. The imposition of a fixed Minimum Annual Resource ("MAR") Requirement, together with a large quantity of lower priced offers from Demand Resources (as defined by PJM) with limited availability, has resulted in a demand curve for Annual Resources that is, in effect, vertical. As a result, Annual Resources have lost the price stabilization, reliability and consumer cost benefits of the sloped demand curve that I described in my 2005 and 2006 RPM affidavits. To restore those benefits for Annual Resources, which have the highest level of reliability due to their absence of seasonal or response limitations, a slope can be introduced in their effective demand curve.

11. To analyze the potential long-run benefits of restoring the slope to the effective demand curve that Annual Resources face, I have applied a version of the dynamic capacity market model used in my 2005-2006 RPM affidavits. The model is simplified so that a range of assumptions concerning costs, investor behavior, and energy demand can be simulated. As in my 2005-2006 affidavits, I conclude that the sloped curve robustly outperforms the vertical demand implied by the MAR Requirement, in terms of generally having a higher probability of installed Annual Resources meeting the requirement and lower consumer costs. Under none of my simulations does the vertical curve outperform a sloped curve in terms of these two crucial objectives.

IV. DEMAND CURVE FOR ANNUAL RESOURCES IMPLIED BY CURRENT MARKET RULES

12. In the affidavits referenced above, I presented arguments that implementation of a sloped demand curve in RPM would result in more stable capacity prices and reserve margins, lower average costs for consumers, and improved resource adequacy (as measured by the average reserve margin) than the vertical demand curve that was, in effect, established by the fixed capacity obligation and deficiency penalty approach used by the previous PJM Installed Capacity ("ICAP") market. I documented the formulation and assumptions of a simulation model that I developed that represented decisions to invest in peaking generation capacity over time in response to levels and variability of energy and capacity prices. My conclusion that a sloped demand curve for capacity in RPM would be superior to a vertical demand curve flowed directly from the assumptions that future energy and capacity prices are uncertain; that willingness to invest depended on forecasts of those uncertain prices, which in turn reflect recent price experience; and finally, that generator investors are risk averse. Investors are risk averse if they prefer an investment with a less uncertain return to one with a more uncertain return, if both have the same long-run average return. The findings of my model that a sloped demand curve is superior in terms of consumer cost and resource adequacy were robust with respect to changes in particular assumptions for the model's parameters concerning price and investor behavior, as long as there is some uncertainty and investors are risk averse to some degree. The Commission acknowledged these benefits of a sloped demand curve when it accepted the settlement that resolved the earlier proceeding and permitted PJM to implement RPM.

13. In early 2011, the Commission approved RPM rule changes that established three different types of capacity products, with varying availability characteristics. These include Limited Demand Resources ("Limited DR"), Extended Summer Demand Resources ("Extended Summer DR"), and Annual Resources (including Annual Demand Resources, Generation Capacity and Energy Efficiency Resources). Limited DR is available only from June through September of each Delivery Year, and must be available for at least ten interruptions during that period, for a maximum of six hours in duration between 12:00 p.m. to 8:00 p.m. Eastern Prevailing Time. Extended Summer DR is available only June, July, August, September, October and May of each Delivery Year, for an unlimited number of interruptions, for a maximum of ten hours in duration between 10:00 a.m. and 10:00 p.m. Eastern Prevailing Time. Annual Resources, other than Annual Demand Resource, are available throughout the year, and have no limits on the frequency of their response. Annual Demand Resources must be available for interruptions throughout the entire Delivery Year, for a maximum of ten hours in duration, between 10:00 a.m. and 10:00 p.m. Eastern Prevailing Time for the months of June, July, August, September, October and May, and between 6:00 a.m. to 9:00 p.m. Eastern Prevailing Time for the months of November through April. Under the rules approved in 2011, PJM sets a minimum requirement for Annual Resources in the RPM Auction clearing process. If needed to procure sufficient quantities of Annual Resources to meet the minimum requirement, a higher price will be paid for Annual Resources in

the RPM Auction, based on the marginal Annual Resource offer needed to meet the minimum requirement.

14. In my opinion, the 2011 rule change has indeed resulted in the implementation of a form of vertical demand curve for the clearing and procurement of Annual Resources, with adverse implications for long-run resource adequacy and consumer costs. Under the current implementation, as long as the RPM Auction procures sufficient Annual Resources to satisfy the MAR Requirement and a sufficient combination of Annual Resources and Extended Summer DR to satisfy the Minimum Extended Summer Resource ("MESR") Requirement, any procured capacity in excess of those requirements up to the intersection with the sloped demand curve can be provided entirely by the Demand Resources with limited availability. This will occur when the more Limited DR is offered at a lower price than offers from incremental quantities of Annual Resources or Extended Summer DR that are in excess of the minimum requirements. It is my understanding that PJM has conducted three of its principal three-year forward capacity auctions under these rules, and that for some of the locational markets in these auctions, procurement has indeed shifted to the more limited resources once the requirement was met for the Annual Resources**.**

15. This situation has two undesirable implications:

a. Under this approach and these conditions, the Annual Resources offered are, in effect, cleared against a vertical demand curve defined by the MAR Requirement.[1] Further, the sloped demand curve beyond the MAR Requirement has no impact on the cleared quantities and clearing prices of the Annual Resources that provide PJM with the highest level of reliability due to their absence of seasonal or response limitations. In this situation, the price received by Annual Resources is determined by the intersection of their overall offer (supply) curve with the MAR Requirement, which, as a fixed quantity, acts as a vertical demand curve with a price cap. Consequently, Annual Resources no longer derive the benefits of price stabilization provided by a sloped demand curve as identified in my 2005 and 2006 analysis and recognized by the Commission. This effective vertical curve is analogous to PJM's ICAP market structure before RPM which assessed a penalty on load serving entities that failed to demonstrate capacity equal to or in excess of expected peak loads plus a stated reserve margin. Just as the fixed-reserve and penalty approach failed to recognize the value of capacity procured beyond the fixed reserve level, PJM's present approach is not adequately

[1] As I understand the current rules, a similar vertical demand curve also can arise at the minimum requirement for the combination of Annual Resources and Extended Summer Demand Resources, *i.e.*, if the price received by annual capacity is set by the intersection of the latter requirement with the supply curve defined by offers from Annual Capacity plus Extended Summer DR. This occurs when that price exceeds both (1) the price defined by the intersection of Annual Capacity offers and the MAR Requirement and (2) the price defined by the intersection of the supply curve consisting of all offers to the RPM market (including Limited DR) and the RPM demand curve. On the other hand, if the price defined by the intersection of Annual Capacity offers and the MAR Requirement is higher than the other two prices, than the MAR Requirement vertical demand curve defines the price received by annual capacity.

recognizing the value of Annual Resources procured beyond the MAR Requirement and results in less stable prices than a sloped curve.

b. The sloped portion of the demand curve beyond the target reliability requirements (MAR and MESR Requirements) is utilized only to clear additional quantities and determine the clearing price of the capacity resource types having the lowest availability and response requirements (lowest reliability value). The long-run reliability and cost benefits provided by a sloped demand curve relative to a vertical demand curve are, in effect, unavailable to the capacity resource type having no seasonal or response limitations and highest reliability value (*i.e.*, Annual Resources) and instead maintained for capacity resource types having the lowest availability and response requirements and lowest reliability value (*i.e.*, Limited DR and Extended Summer DR).

V. COMPARISON OF VERTICAL AND SLOPED DEMAND CURVES FOR ANNUAL RESOURCES

16. I have adapted the model I used in my 2005-2006 affidavits for the purpose of evaluating the impact of the effectively vertical demand curve for Annual Resources implied by the MAR Requirement. In particular, I have compared the performance of a vertical demand curve with sloped versions of a demand curve for Annual Resources that has the same slopes as the PJM RPM sloped demand curve for all resources. In other words, I compare the present situation in which Annual Resources effectively faces a vertical demand curve with a situation in which the slope of the curve has been restored. As in my 2005-2006 affidavits, the performance indices include the probability of achieving capacity targets (in this case, the MAR Requirement for Annual Resources), the average amount of Annual Resources, and costs to consumers. Consumer costs are based on the cost of capacity, amount of capacity procured, and energy and ancillary service gross margins earned by all generation in excess of the running cost of new combustion turbines, the most expensive new resource on the system. (This resource is termed the PJM Reference Resource.) I used the latest data available from PJM to specify the input parameters used in the model (such as average demand growth, growth variability, CONE, and combustion turbine fuel costs). I also performed sensitivity analyses with respect to a number of input assumptions concerning supply offers by peaking generation plants, risk aversion, and other behavioral parameters that are uncertain in order to ascertain whether the sloped demand curve maintains its superior performance over the vertical demand curve when those general assumptions change. As I stated previously, the goal of the analysis is to assess the ability of the demand curve to create a stable capacity market, to meet the reserve requirement each year, and to minimize the costs to consumers.

A. Basic Assumptions and General Methodology

17. Capacity additions in electric power systems are a dynamic process that are influenced by past and anticipated price behavior, and in turn affect future prices through the interplay of supply and demand. The model executes chronologically one year at a

time, simulating the formation of capacity offers by existing and new entrants that are assumed to be combustion turbines with the same cost and operating characteristics as PJM's Reference Resource. The supply offers from existing resources and new entrants interact with the RPM demand curve in the Base Residual Auction for the PJM Region as a whole, without considering Locational Deliverability Areas. The willingness to invest is based upon forecast gross margin (revenue minus variable costs) streams for similar turbines. The model focuses on investments in combustion turbines, for which capacity payments make up a greater fraction of revenues than is the case for other types of capacity. Gross margin projections used in formulating offers for new capacity are informed by five years of experienced margins, consistent with how time series-based forecast models are used to project prices. The willingness to invest, as reflected in new capacity offers in the RPM Auction, is assumed to drop due to risk aversion if the variability in prices translates into significant uncertainty in the revenue stream without increasing average returns.

18. The analysis was based on the same approximating assumption as in the analysis in my previous affidavits concerning the energy and ancillary services ("E&AS") offset used to define the demand curve: that the offset is the same in every year and not adjusted in response to observed offers and market outcomes. These assumptions are implemented in a spreadsheet model that simulates decisions in a series of years. These assumptions combine in the model to show that use of demand curves that increase the stability of prices and provide adequate returns to investment would increase investment in the capacity market and help meet the reserve target at lower costs to consumers.

19. Alternative demand curves (vertical and sloped) are evaluated under the assumption that the RPM Auction takes place three years ahead of the date in which the capacity is made available. Thus, the analysis has been simplified compared to the most elaborate of the 2005-2006 analyses by focusing only on the three year-ahead Base Residual Auction. I used twenty-five simulations, each 100 years in length, as in the 2005-2006 analyses. These simulations are randomly created using a Monte Carlo method to generate shorter-term variations in energy and ancillary services prices arising from weather-induced load fluctuations, as well as longer-term variations in demand growth due to load growth variability.

20. The model is not intended to be a highly detailed representation of the actual mechanics of RPM, nor the current fleet of generation resources in operation. Rather, its purpose is to provide insights on the long-run effects of differently sloped curves upon the dynamics of generation investment in combustion turbines that define the Reference Resource in RPM, given the fundamental assumptions of investor aversion to risk, the importance of new resource investment in the future resource mix, and the presence of large uncertainties about demand growth, weather, and prices. As I stated in my 2005 affidavit, all models are necessarily simplifications of reality, and because many of the parameters of the model cannot be known with certainty, no single set of outputs should be treated as being a definitive statement on the quantitative performance of a demand curve. Instead, I conduct numerous sensitivity analyses around key parameters to determine the patterns of their influence on the model results, and the robustness of any

conclusions about the relative performance of different curves. While the model necessarily simplifies capacity market decisions and impacts, the model is useful for the purpose of understanding qualitative dynamic effects such as whether the relative ranking of different demand curve alternatives is robust under a wide range of assumptions. The model is not accurate enough to make precise quantitative predictions, but its intent is to illuminate several qualitative decisions that must be made when designing capacity markets.

B. Key Input Parameters

21. For these simulations, the combustion turbine capital cost is the annual cost of a combustion turbine based upon the gross Net CONE used in RPM for the Reference Resource. Revenues are from PJM's energy, ancillary services, and RPM markets. Uncertainties are introduced in economic growth and weather. The model determines the profitability of combustion turbines needed to meet the reserve requirement. The time step is one year.

22. The input parameters were updated based on the most recent data available from PJM. The key input parameters are shown in Table 1. The 'target annual capacity' is derived as follows as a percentage of Forecast Peak Load:

Forecast peak load = 100%.
Reliability Requirement
= Forecast Peak Load * Forecast Pool Requirement = 100% * 1.0902 = 109%.
Limited DR/Extended Summer DR Reliability Target
= 10.5% (10.9% UCAP Value).
MAR Requirement
= Reliability Requirement - Limited DR/Extended Summer DR Reliability Target
= 109% – 10.9% = 98.1%.

This MAR Requirement of 98.1% of Forecast Peak Load is used as the 'target annual capacity' for Annual Resources by which I evaluate the resource adequacy performance of both the vertical and sloped demand curve for Annual Resources only. This target defines the quantity intercept of the vertical demand curve I modeled. Meanwhile, I used 101% of this target to derive Point (b) on the sloped curve for my simulations (*i.e.*, a quantity of 99% of the peak load), as shown in Table 1 below, which is analogous to the quantity "IRM + 1%" on the sloped demand curve consistent with the current RPM Auction design. Below, I include, for illustrative purposes, depictions of the vertical demand curve (Figure 1) and sloped demand curve (Figure 2) used in my base case analyses.

Table 1 – Key Input Parameters

Key Input Parameters to 2013 Capacity Market Analysis by Hobbs

Parameter		Comments
Planning Parameters/CT Costs		
Gross CONE, CT based, ICAP $/MW-Year	$139,392	Planning Parameters 2016/2017
Gross CONE, CT based, ICAP $/MW-Day	$381.90	Planning Parameters 2016/2017
Pool-Wide Average EFORd	5.69%	Planning Parameters 2016/2017
Installed Reserve Margin (IRM)	15.6%	Planning Parameters 2016/2017
Forecast Pool Requirement (FPR)	1.0902	Planning Parameters 2016/2017
Demand Resource (DR) Factor	0.955	Planning Parameters 2016/2017
Energy Revenue Offset, $/MW-Year	$23,415	2010-2012 based on PJM avg LMP
Ancillary Services, $/MW-yr	$2,199	Per Tariff
Energy & Ancillary Services (E&AS) Offset, $/MW-year	$25,614	
Net CONE, ICAP $/MW-Year	$113,778	Gross CONE - E&AS Offset
Net CONE, ICAP $/MW-Day	$311.72	Net CONE $/MW-yr / 365
Net CONE, UCAP $/MW-Day	**$330.53**	Net CONE ICAP/(1-Pool-Wide Average EFORd)
CT Operating Cost, $/MWh	$48.68	Consistent with E&AS offset.
Forecast Peak Load/DR Targets/Target Capacity		
Forecast Peak Load, MW	**152,383**	Planning Parameters 2016/2017
Reliability Requirement	166,128	Planning Parameters 2016/2017
Limited+Extended Summer DR Reliability Target, % Peak Load	10.5%	Planning Parameters 2016/2017
Limited+Extended Summer DR Reliability Target, UCAP MW	16,658	
Minimum Annual Resource Requirement, MW	149,469	
Minimum Annual Resource Requirement, % Forecast Peak Load	**98.1%**	Used as Target for Demand Curve
Vertical Demand Curve Parameters		
Maximum UCAP Price, 1.5 Net CONE, $/MW-year	$180,964	UCAP less than the Target
Minimum UCAP Price, $/MW-Day	$0.00	UCAP greater than the Target
Sloped Demand Curve Parameters		
Point (a) UCAP Price, 1.5 Net CONE, $/MW-year	$180,964	
Point (b) UCAP Price, Net CONE, $/MW-year	$120,643	
Point (c) UCAP Price, 0.2 Net CONE, $/MW-year	$24,129	
Point (a) UCAP Level, MW (IRM - 3%)	95.3%	Expressed as fraction of Forecast Peak Load
Point (b) UCAP Level, MW (IRM + 1%)	99.0%	Expressed as fraction of Forecast Peak Load
Point (c) UCAP Level, MW (IRM + 5%)	102.8%	Expressed as fraction of Forecast Peak Load
Load Parameters		
Forecast peak load growth, %/year	1.3%	First 10 years growth from 2013 forecast.
Load forecast uncertainty (weather normalized vs. forecast)	1%	
Weather uncertainty (actual peak vs. weather normalized)	4%	

Figure 1 – Vertical Demand Curve Depiction

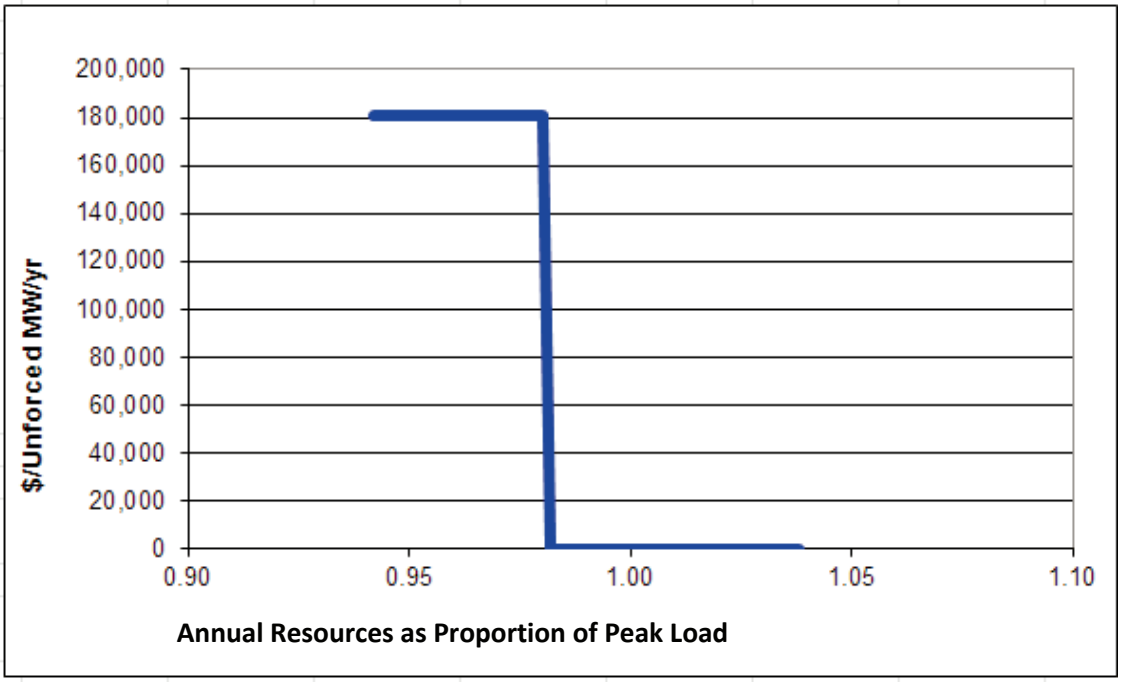
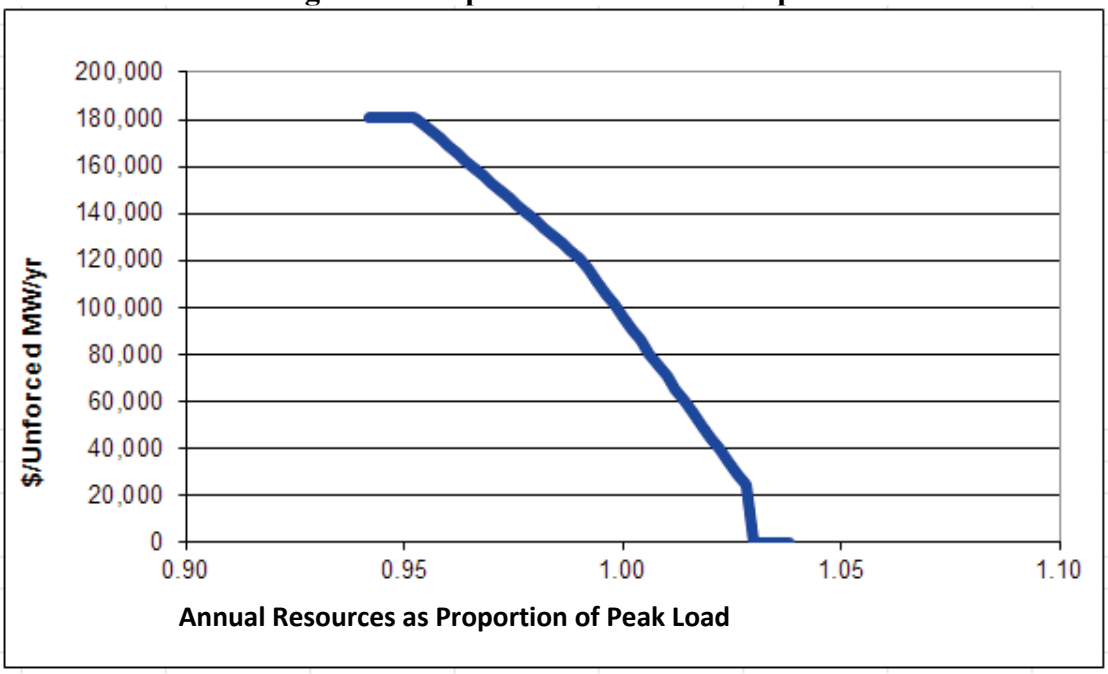


Figure 2 – Sloped Demand Curve Depiction



23. My results, which I present in the following section and detail in Table 2 below, compare vertical and sloped effective demand curves for Annual Resources (Figures 1 and 2) under a base case set of assumptions concerning the demand curve, offer behavior, degree of risk aversion, weighting of recent revenues in the price forecasting algorithm, and degree of uncertainty in load forecasts. The vertical curve pays $180,964 per unforced megawatt of capacity per year to Annual Resources if the amount provided is less than the MAR Requirement, and an amount equal to the intercept of the offer curve

and the vertical demand curve (located at the MAR Requirement, which is 98.1% of the forecast peak load). The sloped curve is horizontal to the left of point (a) (at 95.3% of the peak) at $180,964 (equal to 150% of the assumed CONE), then is interpolated linearly between points (a), (b), and (c) (the coordinates of (b) and (c) are shown in Table 1 above), and finally has a vertical segment between (c) and the quantity axis. After presenting the base case results, I then present results under several alternative sets of assumptions to assess the robustness of my conclusions. The following general assumptions were used in the base cases:

Bid price for new capacity = $0/MW of unforced capacity/year up to the maximum amount that generators are willing to build
Upper limit on capacity additions = 7% (under highly favorable financial conditions)
Risk aversion coefficient = 0.7 (compared to 0.5 which represents risk neutrality, in which only expected returns matter to investors)
Relative weight on recent combustion turbine revenues = Higher (as opposed to an equal weight on most recent 5 years of revenues)
Load forecast uncertainty = 1% (standard deviation of weather normalized peak vs. forecast)

C. Results: Base Case

24. To summarize results for the base case assumptions, which are detailed on the first two rows of Table 2 below, first, I calculated two reserve indices for the sloped and vertical curves:

Percent of years Annual Resources met or exceeded target annual capacity (MAR Requirement)
= 42% for vertical demand curve; 96% for sloped demand curve.
Average amount of Annual Resources in excess of target annual capacity (MAR Requirement), expressed as a percentage of peak load
= -0.62% for vertical demand curve (*i.e.*, below the target, on average); 1.24% for sloped demand curve (*i.e.*, above the target).

25. Next, I divided the revenue impacts of each demand curve into two portions: payments through RPM ("RPM payments"), and payments for energy and ancillary services in excess of the marginal running cost of new combustion turbines ("E&AS gross margin"), which can be interpreted as scarcity revenues arising from scarcity pricing mechanisms or dispatch of units whose marginal costs are greater than new turbines, or a combination of those factors. I normalized these by dividing by the amount of ICAP. For the vertical demand curve:

E&AS gross margin = $96/MW-Day
RPM payments = $350/MW-Day
Total = $446/MW-Day

26. In contrast, the model shows that the revenue required by the risk-averse generators in order to invest decreases by $50/MW-Day under the sloped demand curve:

E&AS gross margin = $57/MW-Day
RPM payments = $339/MW-Day
Total = $396/MW-Day

27. Furthermore, the standard deviations (year-to-year) of the revenue streams are much less under the sloped curve than under the vertical curve, as Table 2 below shows. For instance, under the base case assumptions, the standard deviation of ICAP payments under the vertical curve is $202/MW-day, while for the sloped curve it is $29/MW-day.

28. The more stable but lower revenues under the sloped curve also result in lower but more stable profits, net of investment costs:

Profit for New CT = Gross Margin minus Capital Cost
= $64/MW-Day (standard deviation = $268/MW-day) for vertical curve
= $14/MW-Day (s.d. = $59/MW-Day) for sloped curve

29. The fact that the standard deviation of profit exceeds the average reflects the frequent occurrence of years in which profits (gross margin minus capital costs) are negative.

30. Finally, impacts on consumer payments are expressed by dividing the sum of total E&AS revenues (in excess of the running costs of new turbines) and RPM payments by the annual energy demand expressed in megawatt-hours (MWh) (assuming an annual load factor of 60%, equal to the ratio of the average load to the peak load).

Consumer payments = $30/MWh for vertical curve
= $27/MWh for sloped curve

31. In summary, the sloped demand curve results in increased investment to help meet or exceed the reliability target. This is because capacity prices and total revenues are more stable; risk averse generators are willing to accept lower profits when they are much more stable. Both components of combustion turbine profits (RPM payments and E&AS revenues) are smaller, the latter because of the effect of larger capacity margins on the supply-demand balance in the short-term energy markets. Note also that both long-run averages for combustion turbine profits and consumer payments are lower with the use of the sloped demand curve than with the use of a vertical demand curve. These general conclusions are consistent with those of my 2005-2006 affidavits.

D. Results: Sensitivity Analyses of General Assumptions

32. I changed the general assumptions made in the base case as shown below to perform sensitivity analyses of the above results. These sensitivity analyses included the following cases:

a. The new capacity bid price was increased to $50,000/MW-year ($136.89/MW-day) and $100,000/MW-year ($273.78/MW-day), simulating submission of an offer curve with non-zero prices. This supply curve has similar behavior as a sloped supply curve, in that it stabilizes prices for both vertical and sloped demand curves, the reason being that it puts a floor under the range of possible price responses over the quantity range of interest (values of offered capacity between the existing capacity and the maximum total capacity offered). A sloped supply curve whose prices lie between $50,000/MW-year and $100,000/MW-year would be anticipated to yield results between those resulting from the two offer curves based on those prices.

   These cases can also be interpreted as situations in which the lowest price that Annual Resources would obtain is bounded from below by Limited and Summer Extended DR offers of $50,000 and $100,000/MW-year, respectively. This is because when ample Limited and Summer Extended DR is offered at a non-zero price, the lowest price that annual capacity could obtain is that demand resource offer. This would be the case, for example, when new turbine capacity offers at $0/MW-year and the amount offered is in excess of the MAR Requirement but not the MESR Requirement; in that case, the price that Annual Resources receives is not $0/MW-year, but instead is the price set by Limited and Summer Extended DR. (In particular, the latter price would be the higher of: (a) the price set by the intersection of the supply curve defined by the Summer Extended DR and Annual Resources offers with the MESR Requirement and (b) the price set by the intersection of the overall resource supply curve (from the Annual Resources, Summer Extended DR, and Limited DR offers) and the RPM demand curve.)

b. The upper limit on capacity additions was increased to 10% per year, simulating a situation in which investment could react more quickly to perceived shortages.

c. The risk aversion coefficient was reduced to 0.6 to simulate lower risk aversion.

d. Relative weights (used in the revenue forecasting method) on revenues in the five years previous to the auction were made equal, resulting in more stable forecasts of revenues than forecasts that weight more recent years more heavily.

e. Load Forecast Uncertainty was eliminated, in order to simulate the situation in which investors ignore year-to-year weather-based variations in E&AS

revenues when evaluating investments, and are only concerned with longer-run demand growth uncertainty.

33. The base case results and the sensitivity analysis results are shown Table 2. It can be observed that the changes in various general assumptions did change the quantitative level of performance (capacity adequacy, generator revenues and profits, and consumer costs) of RPM. However, the sloped demand curve still robustly outperforms the vertical demand curve in all cases on both reliability indices, as well as consumer costs. The precise degree to which the sloped curve is superior depends on the assumptions, as would be expected, but the vertical curve is never better. In particular:

a. Increasing the new capacity offers to $50,000/MW-year and $100,000/MW-year yields more stable prices for both curves. This is because the capacity price no longer ranges between $0 and the highest price ($180,964/MW-year), but over a narrower range. This stabilization of price is consistent with the results of the Brattle study[2] that evaluated the actual offer curves submitted to the RPM Base Residual Auctions for given actual supply curves offered in eight BRAs (2007/08 through 2014/15); the sloped RPM demand curve resulted in more stable prices than what a vertical curve would have yielded, although the fact that non-zero offers are made by capacity results in less variation than anticipated by my model when zero offers are assumed.

   The impact of the higher capacity offer prices in my model, and the resulting increase in capacity price stability, is to improve the performance of the vertical curve. However, my conclusion remains (as in the sensitivity analyses in my 2005 affidavit as well) that the performance of the vertical curve (in terms of probability of meeting target, average reserve, and consumer costs) remains less desirable than the sloped curve, although the differences between the two curves narrows.

   In the context of the interpretation of the non-zero capacity offers representing Demand Resource offers for Extended Summer and Limited DR providing a price floor, this mirrors the manner in which Demand Resource offers are clearing beyond the MAR and on either the MESR or on the sloped demand curve. As my simulation results show, the current construct still results in a degradation of resource adequacy versus a sloped curve for Annual Resources.

b. Increasing the upper limit on capacity additions to 10% per year, which is well in excess of any amount of generation investment experienced in PJM, improved the performance of the vertical curve, but the sloped curve still results in better resource adequacy.

[2] Johannes P. Pfeifenberger, Samuel A. Newell, Kathleen Spees, & Attila Hajos, Second Performance Assessment of PJM's Reliability Pricing Model, The Brattle Group, Inc. 106-109 (Aug. 26, 2011), www.brattle.com/system/publications/pdfs/000/004/833/original/Second_Performance_Assessment_of_PJM%27s_Reliability_Pricing_Model_Pfeifenberger_et_al_Aug_26_2011.pdf?1378772133.

c. Lowering the risk aversion coefficient enhances the performance of the vertical curve because the high variability in gross margins becomes less of deterrent to investment, but the sloped curve still yields better resource adequacy. I have also confirmed the theoretical expectation that if risk aversion is entirely eliminated (by using a coefficient slightly above 0.5) then the performance of the two curves is the same, because variability of gross margins becomes irrelevant to investment decisions.

d. Altering the relative weights on recent gross margins deteriorates the performance of both curves by roughly equal amounts. This is because revenues from the more distant past are less relevant than more recent experience when forecasting future revenues.

e. Eliminating consideration of Load Forecast Uncertainty had little effect on the results.

Table 2 – Base Cases and Sensitivity Analysis Results ("s.d." = Standard Deviation; Italicized Text is Sloped Curve Results)

Base Case and Sensitivity Analysis	Reserve Indices		CT Generator Profit, $/Installed MW/day (s.d.)	Components of CT Revenue		Consumer Payments for E/AS Gross Margin + RPM, $/MWh (s.d.)
	% Years Meet or Exceed MAR Require-ment for Annual Capacity	Average % Reserve in excess of MAR Require-ment for Annual Capacity (s.d.)		Energy / AS Gross Margin, $/Installed MW/day (s.d.)	RPM Payments $/Installed, MW/day (s.d.)	
Vertical Annual Curve (Base Case)	42	-0.62 (2.43)	64 (268)	96 (137)	350 (202)	30 (19)
Sloped Curve (Base Case)	*96*	*1.24 (0.65)*	*14 (59)*	*57 (47)*	*339 (29)*	*27 (4)*
Vertical Curve ($50K/MW/yr bid by new capacity)	69	0.21 (1.12)	133 (273)	71 (84)	443 (245)	35 (19)
Vertical Curve ($100K/MW/yr bid by new capacity)	80	0.44 (1.14)	94 (235)	69 (84)	407 (205)	32 (17)
Sloped Curve ($100K/MW/yr bid by new capacity)	*95*	*1.24 (0.69)*	*14 (61)*	*57 (48)*	*339 (31)*	*27 (4)*
Vertical Curve (10% CT capacity addition upper bound)	46	-0.27 (3.01)	32 (294)	98 (150)	316 (217)	27 (21)
Sloped Curve (10% CT capacity addition upper bound)	*98*	*1.24 (0.54)*	*12 (54)*	*56 (45)*	*338 (24)*	*27 (3)*
Vertical Curve (Less Risk Averse: 0.6 Coefficient)	58	0.11 (1.51)	34 (237)	73 (89)	342 (206)	28 (17)
Sloped Curve (Less Risk Averse: 0.6 Coefficient)	*93*	*1.25 (0.79)*	*13 (65)*	*57 (48)*	*338 (36)*	*27 (4)*
Vertical Curve (Equal forecast weights)	40	-1.12 (3.07)	91 (299)	118 (181)	355 (200)	32 (21)
Sloped Curve (Equal forecast weights)	*67*	*0.79 (2.09)*	*30 (140)*	*68 (81)*	*343 (90)*	*28 (9)*
Vertical Curve (No load growth uncertainty)	39	-0.60 (2.41)	50 (256)	88 (108)	345 (206)	29 (18)
Sloped Curve (No load growth uncertainty)	*100*	*1.31 (0.20)*	*9 (37)*	*54 (36)*	*337 (9)*	*26 (2)*

34. This concludes my affidavit.

Dated November 26, 2013

SS:) **State of Maryland**
)
) **Baltimore County**

AFFIDAVIT OF DR. BENJAMIN F. HOBBS

Dr. Benjamin F. Hobbs, being first duly sworn, deposes and says that he has read the foregoing "Affidavit of Benjamin F. Hobbs on behalf of PJM Interconnection, L.L.C.," that he is familiar with the contents thereof, and that the matters and things set forth therein are true and correct to the best of his knowledge, information and belief.

/s/ _____ 11-26-2013
Dr. Benjamin F. Hobbs

Subscribed and sworn to before me this the 26th day of November, 2013.

/s/ _____
Notary Public

My Commission expires: September 11, 2017

JANE E. GALLAGHER
COMMISSION EXPIRES
SEPT
11
2017
BALTIMORE COUNTY, MD.
NOTARY PUBLIC

Attachment B

Revisions to the
PJM Open Access Transmission Tariff
and
PJM Reliability Assurance Agreement

(Identified by Additional Cover Pages)

(Marked / Redline Format)

Section(s) of the
PJM Open Access Transmission Tariff

(Marked / Redline Format)

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers

shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a PJM Member that has the capability to reduce load, or that aggregates customers capable of reducing load. The Demand Resource Provider shall notify the Office of the Interconnection whether such load reduction is provided by a Limited Demand Resource, Extended Summer Demand Resource or an Annual Demand Resource. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource.

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C ~~Extended Summer Demand~~ Sub-Annual Resource Reliability Target

"~~Extended Summer Demand Resource~~ Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for Delivery Years beginning June 1, 2017. As more fully set forth in the PJM Manuals, PJM calculates the ~~Extended Summer DR~~ Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The ~~Extended Summer Demand~~ Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint~~[Reserved]~~

"Sub-Annual Resource Constraint" shall mean, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 [Reserved]

2.33 [Reserved]

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 [Reserved]

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for Delivery Years beginning June 1, 2017 for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability

that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016-2017 and subsequent Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

"Limited Resource Constraint" shall mean, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction for the Zones comprising such Locational Deliverability Area for such Delivery Year.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the ~~Extended Summer Demand~~ Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the ~~Extended Summer Demand~~Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction (as applicable) for such Delivery Year.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology in CONE Areas 1, 2, 3, and 4, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.60A Repowered / Repowering

"Repowering" or "Repowered" shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second

Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017;

d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for Delivery Years starting June 1, 2017;

e~~d~~) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction

~~e~~f) Calculating the EFORd for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction;

~~f~~g) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

~~g~~h) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

~~h~~i) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

~~i~~j) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with section 18.17 of the Operating Agreement, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Attachment DD.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency

Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before July 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2015, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $128,000 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	140,000
BGE, PEPCO ("CONE Area 2")	130,600
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC ("CONE Area 3")	127,500
PPL, MetEd, Penelec ("CONE Area 4")	134,500
Dominion ("CONE Area 5")	114,500

B) Beginning with the 2016-2017 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2015-2016 Delivery Year to which the Applicable H-W Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under

the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the Zone in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction

for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before July 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before July 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) ~~Minimum Annual~~ Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for ~~each~~ the Delivery Years starting~~, beginning with the Delivery Year that starts~~ on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for each Delivery Year beginning with the Delivery Year that commences June 1, 2017, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement, *and all applicable Capacity Import Limits*;

iii) The Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting ~~with~~ June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year; and for the Delivery Year that commences June 1, 2017 and subsequent Delivery Years, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) In addition to the information required to be posted by subsection (a), PJM will post for a Delivery Year, at least sixty (60) days prior to conducting the Base Residual Auction for such Delivery Year, the aggregate megawatt quantity of, for the PJM Region, all Self-Supply Exemption requests under section 5.14(h), all Competitive Entry Exemption requests under section 5.14(h), and such exemptions granted in each such category, and to the extent PJM has made any such determination, notice that PJM has determined that one or more state-sponsored or state-mandated procurement processes is Competitive and Non-Discriminatory pursuant to section 5.14(h).

c) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

d) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

e) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

f) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity requested and granted in the Self-Supply and Competitive Entry Exemption categories in the EMAAC, MAAC and Rest of RTO LDAs/regions; the aggregate megawatt quantity cleared in the RPM Auction for Self-Supply and Competitive Entry Exemption categories; and the aggregate megawatt quantity of Self-Supply and Competitive Entry Exemptions requested and granted for any LDA other than those specified in the preceding clause if the LDA has more than four new generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth business day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is

necessary to post modified results, it shall provide notification of its intent to do so, together with all available supporting documentation, by no later than 5:00 p.m. of the seventh business day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth business day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement *and any applicable Capacity Import Limit*;
- for Delivery Years starting ~~with~~ June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; and for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;
- the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple

possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year.

b) Scheduled Incremental Auctions

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- The PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- ~~the~~ The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- *All applicable Capacity Import Limits;*
- For each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;
- ~~f~~For Delivery Years starting ~~with~~ June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; and for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and

- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(2) of this Attachment, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(1) of this Attachment, and the conditions stated in section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (C) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (D) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii). If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by section 5.4(c)(3)(i) of this Attachment, the Office of the Interconnection first shall determine the total quantity of (A) the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (C) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (D) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by section 5.4(c)(3)(ii) of this Attachment; provided, however, that the

amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (C) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. If more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction.

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

(A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are

charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- *All applicable Capacity Import Limits;*
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be ~~the sum of the following: (1)~~ the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable ~~(2) the~~ Locational Price Adders, ~~if any in such LDA, (3) the~~ Annual Resource Price Adders, ~~if any, and (4) the~~ Extended Summer Resource Price Adders, Limited Resource Price Decrements, and Sub-Annual Resource Price Decrements~~if any~~, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the

Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-

block quantity, if any, from its first-year Sell Offer satisfying section 5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) *General Rule.* Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, *or a Unit-Specific Exception* with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) *Applicability.* A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including *R*epowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle *technology*) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 *or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction*; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility *(as defined in Part 292 of FERC's regulations)*, where the Capacity Market Seller is *the* owner of the Qualifying Facility *or has contracted for the Unforced Capacity of such facility* and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) *MOPR Floor Offer Price.* The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the Delivery Year commencing on June 1, 2015, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), a combined cycle generator ("CC"), and an integrated gasification combined cycle generator ("IGCC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CT $/MW-yr	140,000	130,600	127,500	134,500	114,500
CC $/MW-yr	173,000	152,600	166,000	166,000	147,000
IGCC $/MW-yr	582,042	558,486	547,240	537,306	541,809

i) Commencing with the Delivery Year that begins on June 1, 2016, the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above, except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such

section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3,198 per MW-year.

(4) *Duration.* The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until *(and including)* the *first Delivery Year for* which *a* Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) *Effect of Exemption or Exception.* To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). *To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process*. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption *or exception* and cleared the RPM Auction for which it obtained such exemption *or exception* shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(*10*) hereof.

(6) *Self-Supply Exemption.* A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a *Vertically Integrated U*tility and the MOPR Screened Generation Resource is planned consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale

power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE's Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW
Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE's future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

v*i*) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vii) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-

Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. *Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak.* Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) <u>*Competitive Entry Exemption*</u>. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs *of the MOPR Screened Generation Resource* are recovered from customers either directly or indirectly through a non-bypassable charge, *except in*

the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be "Competitive and Non-Discriminatory" only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that

include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(*9*) *Exemption/Exception Process.*

i) *The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.*

ii) The Capacity Market Seller must submit its request for a *Unit-Specific Exception,* Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption *or exception* that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption *or exception* criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

*i*ii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption *or exception* request. The Office of the Interconnection shall also review all exemption a*nd exception* requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption *or exception* request. The Office of the Interconnection shall reject a requested exemption *or exception* if the Capacity Market Seller*'s request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request.* If the Office of the Interconnection does not provide its determination *on an exemption or exception request* by no later than sixty-five (65) days after receipt of the exemption *or exception* request, the request shall be deemed granted. *Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (*5*) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request.* A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(*10*) *Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.*

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the

exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(*10*) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This Transition Provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, "Transition Delivery Years" and each a "Transition Delivery Year") by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a "Qualified DR Provider."

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission's order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this Transition Provision. A Demand Resource cleared for a Transition Delivery Year is not viable

for purposes of this Transition Provision to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

   DRTC = (IAP – BRP) * DRMW

   Where:

   DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

   IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

   BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

   DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this Transition Provision, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

c. an aggregate amount that exceeds:

(i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

(ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

(iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this Transition Provision shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this Transition Provision, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the

Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

Section(s) of the
PJM Reliability Assurance Agreement

(Marked / Redline Format)

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. For the 2016/2017 Delivery Year and prior Delivery Years, t~~T~~he set of Capacity Resources designated in the FRR Capacity Plan must meet the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation. For the 2017/2018 Delivery Year and subsequent Delivery Years, the set of Capacity Resources designated in the FRR Capacity Plan must satisfy the Limited Resource Constraints and the Sub-Annual Resource Constraints applicable to the FRR Entity's capacity obligation. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price

resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity.

5. For each LDA for which the Office of the Interconnection has established a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA. Such minimum percentage ("Percentage Internal Resources Required") will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement.

6. An FRR Entity may reduce such minimum percentage as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the capacity emergency transfer limit for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any

such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days of the submittal of the FRR Capacity Plan. If the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the

load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

F. FRR Daily Unforced Capacity Obligations and Deficiency Charges

1. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = [(OPL * Final Zonal FRR Scaling Factor) – Nominal PRD Value committed by the FRR Entity] * FPR

where:

OPL =Obligation Peak Load, defined as the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal FRR Scaling Factor = FZPLDY/FZWNSP;

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year.

2. An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in such entity's FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Such FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times (1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions).

3. If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of this Schedule.

4. The shortages in meeting the minimum requirement within the constrained zones and the shortage in meeting the total obligation are first calculated. The shortage in the unconstrained area is calculated as the total shortage less shortages in constrained zones and excesses in constrained zones (the shortage is zero if this is a negative number). The Capacity Deficiency Charge is charged to the shortage in each zone and in the unconstrained area separately. This procedure is used to allow the use of capacity excesses from constrained zones to reduce shortage in the unconstrained area and to disallow the use of capacity excess from unconstrained area to reduce shortage in constrained zones.

5. For Delivery Years during the period starting June 1, 2014 and ending May 31, 2017, ~~T~~the shortages in meeting the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation are calculated separately. For such period, ~~T~~the applicable penalty rate is calculated for Annual Resources, Extended Summer Demand Resources, and Limited Resources as (1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions). For Delivery Years beginning June 1, 2017, the FRR Entity shall receive no credit for Limited Demand Resources to the extent committed in excess of the applicable Limited Resource Constraint and shall receive no credit for the sum of Limited Demand Resources and Extended Summer Demand Resources to the extent the sum of the Unforced Capacity of such resources exceeds the applicable Sub-Annual Resource Constraint.

Attachment C

Revisions to the
PJM Open Access Transmission Tariff
and
PJM Reliability Assurance Agreement

(Identified by Additional Cover Pages)

(Clean Format)

Section(s) of the
PJM Open Access Transmission Tariff

(Clean Format)

2. DEFINITIONS

Definitions specific to this Attachment are set forth below. In addition, any capitalized terms used in this Attachment not defined herein shall have the meaning given to such terms elsewhere in this Tariff or in the RAA. References to section numbers in this Attachment DD refer to sections of this attachment, unless otherwise specified.

2.1A Annual Demand Resource

"Annual Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.1B Annual Resource

"Annual Resource" shall mean a Generation Capacity Resource, an Energy Efficiency Resource or an Annual Demand Resource.

2.1C Annual Resource Price Adder

"Annual Resource Price Adder" shall mean, for Delivery Years starting June 1, 2014 and ending May 31, 2017, an addition to the marginal value of Unforced Capacity and the Extended Summer Resource Price Adder as necessary to reflect the price of Annual Resources required to meet the applicable Minimum Annual Resource Requirement.

2.1D Annual Revenue Rate

"Annual Revenue Rate" shall mean the rate employed to assess a compliance penalty charge on a Demand Resource Provider under section 11.

2.2 Avoidable Cost Rate

"Avoidable Cost Rate" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.3 Base Load Generation Resource

"Base Load Generation Resource" shall mean a Generation Capacity Resource that operates at least 90 percent of the hours that it is available to operate, as determined by the Office of the Interconnection in accordance with the PJM Manuals.

2.4 Base Offer Segment

"Base Offer Segment" shall mean a component of a Sell Offer based on an existing Generation Capacity Resource, equal to the Unforced Capacity of such resource, as determined in accordance with the PJM Manuals. If the Sell Offers of multiple Market Sellers are based on a single existing Generation Capacity Resource, the Base Offer Segments of such Market Sellers

shall be determined pro rata based on their entitlements to Unforced Capacity from such resource.

2.5 Base Residual Auction

"Base Residual Auction" shall mean the auction conducted three years prior to the start of the Delivery Year to secure commitments from Capacity Resources as necessary to satisfy any portion of the Unforced Capacity Obligation of the PJM Region not satisfied through Self-Supply.

2.6 Buy Bid

"Buy Bid" shall mean a bid to buy Capacity Resources in any Incremental Auction.

2.7 Capacity Credit

"Capacity Credit" shall have the meaning specified in Schedule 11 of the Operating Agreement, including Capacity Credits obtained prior to the termination of such Schedule applicable to periods after the termination of such Schedule.

2.8 Capacity Emergency Transfer Limit

"Capacity Emergency Transfer Limit" or "CETL" shall have the meaning provided in the Reliability Assurance Agreement.

2.9 Capacity Emergency Transfer Objective

"Capacity Emergency Transfer Objective" or "CETO" shall have the meaning provided in the Reliability Assurance Agreement.

2.9A Capacity Export Transmission Customer

"Capacity Export Transmission Customer" shall mean a customer taking point to point transmission service under Part II of this Tariff to export capacity from a generation resource located in the PJM Region that is delisted from Capacity Resource status as described in section 5.6.6(d).

2.9B Capacity Import Limit

"Capacity Import Limit" shall have the meaning provided in the Reliability Assurance Agreement.

2.10 Capacity Market Buyer

"Capacity Market Buyer" shall mean a Member that submits bids to buy Capacity Resources in any Incremental Auction.

2.11 Capacity Market Seller

"Capacity Market Seller" shall mean a Member that owns, or has the contractual authority to control the output or load reduction capability of, a Capacity Resource, that has not transferred such authority to another entity, and that offers such resource in the Base Residual Auction or an Incremental Auction.

2.12 Capacity Resource

"Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.13 Capacity Resource Clearing Price

"Capacity Resource Clearing Price" shall mean the price calculated for a Capacity Resource that offered and cleared in a Base Residual Auction or Incremental Auction, in accordance with Section 5.

2.14 Capacity Transfer Right

"Capacity Transfer Right" shall mean a right, allocated to LSEs serving load in a Locational Deliverability Area, to receive payments, based on the transmission import capability into such Locational Deliverability Area, that offset, in whole or in part, the charges attributable to the Locational Price Adder, if any, included in the Zonal Capacity Price calculated for a Locational Delivery Area.

2.14A Conditional Incremental Auction

"Conditional Incremental Auction" shall mean an Incremental Auction conducted for a Delivery Year if and when necessary to secure commitments of additional capacity to address reliability criteria violations arising from the delay in a Backbone Transmission upgrade that was modeled in the Base Residual Auction for such Delivery Year.

2.15 CONE Area

"CONE Area" shall mean the areas listed in section 5.10(a)(iv)(A) and any LDAs established as CONE Areas pursuant to section 5.10(a)(iv)(B).

2.16 Cost of New Entry

"Cost of New Entry" or "CONE" shall mean the nominal levelized cost of a Reference Resource, as determined in accordance with section 5.

2.16A Credit-Limited Offer

"Credit-Limited Offer" shall have the meaning provided in Attachment Q to this Tariff.

2.17 Daily Deficiency Rate

"Daily Deficiency Rate" shall mean the rate employed to assess certain deficiency charges under sections 7, 8, 9, or 13.

2.18 Daily Unforced Capacity Obligation

"Daily Unforced Capacity Obligation" shall mean the capacity obligation of a Load Serving Entity during the Delivery Year, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.19 Delivery Year

Delivery Year shall mean the Planning Period for which a Capacity Resource is committed pursuant to the auction procedures specified in Section 5.

2.20 Demand Resource

"Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.21 Demand Resource Factor

"Demand Resource Factor" shall have the meaning specified in the Reliability Assurance Agreement.

2.22 Demand Resource Provider

"Demand Resource Provider" shall mean a PJM Member that has the capability to reduce load, or that aggregates customers capable of reducing load. The Demand Resource Provider shall notify the Office of the Interconnection whether such load reduction is provided by a Limited Demand Resource, Extended Summer Demand Resource or an Annual Demand Resource. A Curtailment Service Provider, as defined in the Operating Agreement, may be a Demand Resource Provider, provided it qualifies its load reduction capability as a Limited Demand Resource, Extended Summer Demand Resource, or Annual Demand Resource.

2.23 EFORd

"EFORd" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24 Energy Efficiency Resource

"Energy Efficiency Resource" shall have the meaning specified in the PJM Reliability Assurance Agreement.

2.24A Extended Summer Demand Resource

"Extended Summer Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.24B Extended Summer Resource Price Adder

"Extended Summer Resource Price Adder" shall mean an addition to the marginal value of Unforced Capacity as necessary to reflect the price of Annual Resources and Extended Summer Demand Resources required to meet the applicable Minimum Extended Summer Resource Requirement.

2.24C Sub-Annual Resource Reliability Target

"Sub-Annual Reliability Target" for the PJM Region or an LDA, shall mean the maximum amount of the combination of Extended Summer Demand Resources and Limited Demand Resources in Unforced Capacity determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity, that shall be used to calculate the Minimum Annual Resource Requirement for Delivery Years through May 31, 2017 and the Sub-Annual Resource Constraint for Delivery Years beginning June 1, 2017. As more fully set forth in the PJM Manuals, PJM calculates the Sub-Annual Resource Reliability Target, by first determining a reference annual loss of load expectation ("LOLE") assuming no Demand Resources. The calculation for the unconstrained portion of the PJM Region uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast and iteratively shifting the load distributions to result in the Installed Reserve Margin established for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Installed Reserve Margin study for the Delivery Year in question). The calculation for each relevant LDA uses a daily distribution of loads under a range of weather scenarios (based on the most recent load forecast for the Delivery Year in question) and a weekly capacity distribution (based on the cumulative capacity availability distributions developed for the Capacity Emergency Transfer Objective study for the Delivery Year in question). For the relevant LDA calculation, the weekly capacity distributions are adjusted to reflect the Capacity Emergency Transfer Limit for the Delivery Year in question.

For both the PJM Region and LDA analyses, PJM then models the commitment of varying amounts of DR (displacing otherwise committed generation) as interruptible from May 1 through October 31 and unavailable from November 1 through April 30 and calculates the LOLE at each DR level. The Extended Summer DR Reliability Target is the DR amount, stated as a percentage of the unrestricted peak load, that produces no more than a ten percent increase in the LOLE, compared to the reference value. The Sub-Annual Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.25 Sub-Annual Resource Constraint

"Sub-Annual Resource Constraint" shall mean, for the PJM Region or for each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources and Extended Summer Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Sub-Annual Resource Reliability Target for the PJM Region or for such LDA, respectively, minus the Short-Term Resource Procurement Target for the PJM Region or for such LDA, respectively.

2.26 Final RTO Unforced Capacity Obligation

"Final RTO Unforced Capacity Obligation" shall mean the capacity obligation for the PJM Region, determined in accordance with Schedule 8 of the Reliability Assurance Agreement.

2.26A [Reserved]

2.27 First Incremental Auction

"First Incremental Auction" shall mean an Incremental Auction conducted 20 months prior to the start of the Delivery Year to which it relates.

2.28 Forecast Pool Requirement

"Forecast Pool Requirement" shall have the meaning specified in the Reliability Assurance Agreement.

2.29 [Reserved]

2.30 [Reserved]

2.31 Generation Capacity Resource

"Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.32 [Reserved]

2.33 [Reserved]

2.34 Incremental Auction

"Incremental Auction" shall mean any of several auctions conducted for a Delivery Year after the Base Residual Auction for such Delivery Year and before the first day of such Delivery Year, including the First Incremental Auction, Second Incremental Auction, Third Incremental Auction or Conditional Incremental Auction. Incremental Auctions (other than the Conditional Incremental Auction), shall be held for the purposes of:

(i) allowing Market Sellers that committed Capacity Resources in the Base Residual Auction for a Delivery Year, which subsequently are determined to be unavailable to deliver the committed Unforced Capacity in such Delivery Year (due to resource retirement, resource cancellation or construction delay, resource derating, EFORD increase, a decrease in the Nominated Demand Resource Value of a Planned Demand Resource, delay or cancellation of a Qualifying Transmission Upgrade, or similar occurrences) to submit Buy Bids for replacement Capacity Resources; and

(ii) allowing the Office of the Interconnection to reduce or increase the amount of committed capacity secured in prior auctions for such Delivery Year if, as a result of changed circumstances or expectations since the prior auction(s), there is, respectively, a significant excess or significant deficit of committed capacity for such Delivery Year, for the PJM Region or for an LDA.

2.35 Incremental Capacity Transfer Right

"Incremental Capacity Transfer Right" shall mean a Capacity Transfer Right allocated to a Generation Interconnection Customer or Transmission Interconnection Customer obligated to fund a transmission facility or upgrade, to the extent such upgrade or facility increases the transmission import capability into a Locational Deliverability Area, or a Capacity Transfer Right allocated to a Responsible Customer in accordance with Schedule 12A of the Tariff.

2.36 [Reserved]

2.36A Limited Demand Resource

"Limited Demand Resource**"** shall have the meaning specified in the Reliability Assurance Agreement.

2.36B Limited Demand Resource Reliability Target

"Limited Demand Resource Reliability Target**"** for the PJM Region or an LDA, shall mean the maximum amount of Limited Demand Resources determined by PJM to be consistent with the maintenance of reliability, stated in Unforced Capacity that shall be used to calculate the Minimum Extended Summer Demand Resource Requirement for Delivery Years through May 31, 2017 and the Limited Resource Constraint for Delivery Years beginning June 1, 2017 for the PJM Region or such LDA. As more fully set forth in the PJM Manuals, PJM calculates the Limited Demand Resource Reliability Target by first: i) testing the effects of the ten-interruption requirement by comparing possible loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using the cumulative capacity distributions employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region

and for the relevant LDAs) more than ten times over those peak days; ii) testing the six-hour duration requirement by calculating the MW difference between the highest hourly unrestricted peak load and seventh highest hourly unrestricted peak load on certain high peak load days (e.g., the annual peak, loads above the weather normalized peak, or days where load management was called) in recent years, then dividing those loads by the forecast peak for those years and averaging the result; and (iii) (for the 2016-2017 and subsequent Delivery Years) testing the effects of the six-hour duration requirement by comparing possible hourly loads on peak days under a range of weather conditions (from the daily load forecast distributions for the Delivery Year in question) against possible generation capacity on such days under a range of conditions (using a Monte Carlo model of hourly capacity levels that is consistent with the capacity model employed in the Installed Reserve Margin study for the PJM Region and in the Capacity Emergency Transfer Objective study for the relevant LDAs for such Delivery Year) and, by varying the assumed amounts of DR that is committed and displaces committed generation, determines the DR penetration level at which there is a ninety percent probability that DR will not be called (based on the applicable operating reserve margin for the PJM Region and for the relevant LDAs) for more than six hours over any one or more of the tested peak days. Second, PJM adopts the lowest result from these three tests as the Limited Demand Resource Reliability Target. The Limited Demand Resource Reliability Target shall be expressed as a percentage of the forecasted peak load of the PJM Region or such LDA and is converted to Unforced Capacity by multiplying [the reliability target percentage] times [the Forecast Pool Requirement] times [the DR Factor] times [the forecasted peak load of the PJM Region or such LDA, reduced by the amount of load served under the FRR Alternative].

2.36C Limited Resource Constraint

"Limited Resource Constraint" shall mean, for the PJM Region or each LDA for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for a Delivery Year, a limit on the total amount of Unforced Capacity that can be committed as Limited Demand Resources for such Delivery Year in the PJM Region or in such LDA, calculated as the Limited Demand Resource Reliability Target for the PJM Region or such LDA, respectively, minus the Short Term Resource Procurement Target for the PJM Region or such LDA, respectively.

2.36D Limited Resource Price Decrement

"Limited Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Limited Demand Resources and the clearing price for Extended Summer Demand Resources and Annual Resources, representing the cost to procure additional Extended Summer Demand Resources or Annual Resources out of merit order when the Limited Resource Constraint is binding.

2.37 Load Serving Entity (LSE)

"Load Serving Entity" or "LSE" shall have the meaning specified in the Reliability Assurance Agreement.

2.38 Locational Deliverability Area (LDA)

"Locational Deliverability Area" or "LDA" shall mean a geographic area within the PJM Region that has limited transmission capability to import capacity to satisfy such area's reliability requirement, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, and as specified in Schedule 10.1 of the Reliability Assurance Agreement.

2.39 Locational Deliverability Area Reliability Requirement

"Locational Deliverability Area Reliability Requirement" shall mean the projected internal capacity in the Locational Deliverability Area plus the Capacity Emergency Transfer Objective for the Delivery Year, as determined by the Office of the Interconnection in connection with preparation of the Regional Transmission Expansion Plan, less the minimum internal resources required for all FRR Entities in such Locational Deliverability Area, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction for the Zones comprising such Locational Deliverability Area for such Delivery Year.

2.40 Locational Price Adder

"Locational Price Adder" shall mean an addition to the marginal value of Unforced Capacity within an LDA as necessary to reflect the price of Capacity Resources required to relieve applicable binding locational constraints.

2.41 Locational Reliability Charge

"Locational Reliability Charge" shall have the meaning specified in the Reliability Assurance Agreement.

2.41A Locational UCAP

"Locational UCAP" shall mean unforced capacity that a Member with available uncommitted capacity sells in a bilateral transaction to a Member that previously committed capacity through an RPM Auction but now requires replacement capacity to fulfill its RPM Auction commitment. The Locational UCAP Seller retains responsibility for performance of the resource providing such replacement capacity.

2.41B Locational UCAP Seller

"Locational UCAP Seller" shall mean a Member that sells Locational UCAP.

2.41C Market Seller Offer Cap

"Market Seller Offer Cap" shall mean a maximum offer price applicable to certain Market Sellers under certain conditions, as determined in accordance with section 6 of Attachment DD and section II.E of Attachment M - Appendix.

2.41D Minimum Annual Resource Requirement

"Minimum Annual Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Annual Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Sub-Annual Resource Reliability Target for the RTO in Unforced Capacity]. For an LDA, the Minimum Annual Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Sub-Annual Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.41E Minimum Extended Summer Resource Requirement

"Minimum Extended Summer Resource Requirement" shall mean, for Delivery Years through May 31, 2017, the minimum amount of capacity that PJM will seek to procure from Extended Summer Demand Resources and Annual Resources for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. For the PJM Region, the Minimum Extended Summer Resource Requirement shall be equal to the RTO Reliability Requirement minus [the Limited Demand Resource Reliability Target for the PJM Region in Unforced Capacity]. For an LDA, the Minimum Extended Summer Resource Requirement shall be equal to the LDA Reliability Requirement minus [the LDA CETL] minus [the Limited Demand Resource Reliability Target for such LDA in Unforced Capacity]. The LDA CETL may be adjusted pro rata for the amount of load served under the FRR Alternative.

2.42 Net Cost of New Entry

"Net Cost of New Entry" shall mean the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset, as defined in Section 5.

2.43 Nominated Demand Resource Value

"Nominated Demand Resource Value" shall mean the amount of load reduction that a Demand Resource commits to provide either through direct load control, firm service level or guaranteed load drop programs. For existing Demand Resources, the maximum Nominated Demand Resource Value is limited, in accordance with the PJM Manuals, to the value appropriate for the method by which the load reduction would be accomplished, at the time the Base Residual Auction or Incremental Auction is being conducted.

2.43A Nominated Energy Efficiency Value

"Nominated Energy Efficiency Value" shall mean the amount of load reduction that an Energy Efficiency Resource commits to provide through installation of more efficient devices or equipment or implementation of more efficient processes or systems.

2.44 [Reserved]

2.45 Opportunity Cost

"Opportunity Cost" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.46 Peak-Hour Dispatch

"Peak-Hour Dispatch" shall mean, for purposes of calculating the Energy and Ancillary Services Revenue Offset under section 5 of this Attachment, an assumption, as more fully set forth in the PJM Manuals, that the Reference Resource is committed in the Day-Ahead Energy Market in four distinct blocks of four hours of continuous output for each block from the peak-hour period beginning with the hour ending 0800 EPT through to the hour ending 2300 EPT for any day when the average day-ahead LMP for the area for which the Net Cost of New Entry is being determined is greater than, or equal to, the cost to generate (including the cost for a complete start and shutdown cycle) for at least two hours during each four-hour block, where such blocks shall be assumed to be committed independently; provided that, if there are not at least two economic hours in any given four-hour block, then the Reference Resource shall be assumed not to be committed for such block; and to the extent not committed in any such block in the Day-Ahead Energy Market under the above conditions based on Day-Ahead LMPs, is dispatched in the Real-Time Energy Market for such block if the Real-Time LMP is greater than or equal to the cost to generate under the same conditions as described above for the Day-Ahead Energy Market.

2.47 Peak Season

"Peak Season" shall mean the weeks containing the 24th through 36th Wednesdays of the calendar year. Each such week shall begin on a Monday and end on the following Sunday, except for the week containing the 36th Wednesday, which shall end on the following Friday.

2.48 Percentage Internal Resources Required

"Percentage Internal Resources Required" shall have the meaning specified in the Reliability Assurance Agreement.

2.49 Planned Demand Resource

"Planned Demand Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50 Planned External Generation Capacity Resource

"Planned External Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.50A Planned Generation Capacity Resource

"Planned Generation Capacity Resource" shall have the meaning specified in the Reliability Assurance Agreement.

2.51 Planning Period

"Planning Period" shall have the meaning specified in the Reliability Assurance Agreement.

2.52 PJM Region

"PJM Region" shall have the meaning specified in the Reliability Assurance Agreement.

2.53 PJM Region Installed Reserve Margin

"PJM Region Installed Reserve Margin" shall have the meaning specified in the Reliability Assurance Agreement.

2.54 PJM Region Peak Load Forecast

"PJM Region Peak Load Forecast" shall mean the peak load forecast used by the Office of the Interconnection in determining the PJM Region Reliability Requirement, and shall be determined on both a preliminary and final basis as set forth in section 5.

2.55 PJM Region Reliability Requirement

"PJM Region Reliability Requirement" shall mean, for purposes of the Base Residual Auction, the Forecast Pool Requirement multiplied by the Preliminary PJM Region Peak Load Forecast, less the sum of all Preliminary Unforced Capacity Obligations of FRR Entities in the PJM Region; and, for purposes of the Incremental Auctions, the Forecast Pool Requirement multiplied by the updated PJM Region Peak Load Forecast, less the sum of all updated Unforced Capacity Obligations of FRR Entities in the PJM Region, and less any necessary adjustment for Price Responsive Demand proposed in a PRD Plan or committed following an RPM Auction (as applicable) for such Delivery Year.

2.56 Projected PJM Market Revenues

"Projected PJM Market Revenues" shall mean a component of the Market Seller Offer Cap calculated in accordance with section 6.

2.57 Qualifying Transmission Upgrade

"Qualifying Transmission Upgrade" shall mean a proposed enhancement or addition to the Transmission System that: (a) will increase the Capacity Emergency Transfer Limit into an LDA by a megawatt quantity certified by the Office of the Interconnection; (b) the Office of the Interconnection has determined will be in service on or before the commencement of the first Delivery Year for which such upgrade is the subject of a Sell Offer in the Base Residual Auction; (c) is the subject of a Facilities Study Agreement executed before the conduct of the Base Residual Auction for such Delivery Year and (d) a New Service Customer is obligated to fund through a rate or charge specific to such facility or upgrade.

2.58 Reference Resource

"Reference Resource" shall mean a combustion turbine generating station, configured with two General Electric Frame 7FA turbines with inlet air cooling to 50 degrees, Selective Catalytic Reduction technology in CONE Areas 1, 2, 3, and 4, dual fuel capability, and a heat rate of 10.096 Mmbtu/ MWh.

2.59 Reliability Assurance Agreement

"Reliability Assurance Agreement" shall mean that certain "Reliability Assurance Agreement Among Load-Serving Entities in the PJM Region," on file with FERC as PJM Interconnection, L.L.C. Rate Schedule FERC No.44.

2.60 Reliability Pricing Model Auction

"Reliability Pricing Model Auction" or "RPM Auction" shall mean the Base Residual Auction or any Incremental Auction.

2.60A Repowered / Repowering

"Repowering" or "Repowered" shall refer to a partial or total replacement of existing steam production equipment with new technology or a partial or total replacement of steam production process and power generation equipment, or an addition of steam production and/or power generation equipment, or a change in the primary fuel being used at the plant. A resource can be considered Repowered whether or not such aforementioned replacement, addition, or fuel change provides an increase in installed capacity, and whether or not the pre-existing plant capability is formally deactivated or retired.

2.61 Resource Substitution Charge

"Resource Substitution Charge" shall mean a charge assessed on Capacity Market Buyers in an Incremental Auction to recover the cost of replacement Capacity Resources.

2.61A Scheduled Incremental Auctions

"Scheduled Incremental Auctions" shall refer to the First, Second, or Third Incremental Auction.

2.62 Second Incremental Auction

"Second Incremental Auction" shall mean an Incremental Auction conducted ten months before the Delivery Year to which it relates.

2.63 Sell Offer

"Sell Offer" shall mean an offer to sell Capacity Resources in a Base Residual Auction, Incremental Auction, or Reliability Backstop Auction.

2.64 [Reserved for Future Use]

2.65 Self-Supply

"Self-Supply" shall mean Capacity Resources secured by a Load-Serving Entity, by ownership or contract, outside a Reliability Pricing Model Auction, and used to meet obligations under this Attachment or the Reliability Assurance Agreement through submission in a Base Residual Auction or an Incremental Auction of a Sell Offer indicating such Market Seller's intent that such Capacity Resource be Self-Supply. Self-Supply may be either committed regardless of clearing price or submitted as a Sell Offer with a price bid. A Load Serving Entity's Sell Offer with a price bid for an owned or contracted Capacity Resource shall not be deemed "Self-Supply," unless it is designated as Self-Supply and used by the LSE to meet obligations under this Attachment or the Reliability Assurance Agreement.

2.65A Short-Term Resource Procurement Target

"Short-Term Resource Procurement Target" shall mean, as to the PJM Region, for purposes of the Base Residual Auction, 2.5% of the PJM Region Reliability Requirement determined for such Base Residual Auction, for purposes of the First Incremental Auction, 2% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, for purposes of the Second Incremental Auction, 1.5% of the of the PJM Region Reliability Requirement as calculated at the time of the Base Residual Auction; and, as to any Zone, an allocation of the PJM Region Short-Term Resource Procurement Target based on the Preliminary Zonal Forecast Peak Load, reduced by the amount of load served under the FRR Alternative. For any LDA, the LDA Short-Term Resource Procurement Target shall be the sum of the Short-Term Resource Procurement Targets of all Zones in the LDA.

2.65B Short-Term Resource Procurement Target Applicable Share

"Short-Term Resource Procurement Target Applicable Share" shall mean: (i) for the PJM Region, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction and, as to the Third Incremental Auction for the PJM Region, 0.6 times such target; and (ii) for an LDA, as to the First and Second Incremental Auctions, 0.2 times the Short-Term Resource Procurement Target used in the Base Residual Auction for such LDA and, as to the Third Incremental Auction, 0.6 times such target.

2.65C Sub-Annual Resource Price Decrement

"Sub-Annual Resource Price Decrement" shall mean, for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, a difference between the clearing price for Extended Summer Demand Resources and the clearing price for Annual Resources, representing the cost to procure additional Annual Resources out of merit order when the Sub-Annual Resource Constraint is binding.

2.66 Third Incremental Auction

"Third Incremental Auction" shall mean an Incremental Auction conducted three months before the Delivery Year to which it relates.

2.67 [Reserved for Future Use]

2.68 Unconstrained LDA Group

"Unconstrained LDA Group" shall mean a combined group of LDAs that form an electrically contiguous area and for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD. Any LDA for which a separate Variable Resource Requirement Curve has not been established under Section 5.10 of Attachment DD shall be combined with all other such LDAs that form an electrically contiguous area.

2.69 Unforced Capacity

"Unforced Capacity" shall have the meaning specified in the Reliability Assurance Agreement.

2.69A Updated VRR Curve

"Updated VRR Curve" shall mean the Variable Resource Requirement Curve as defined in section 5.10(a) of this Attachment for use in the Base Residual Auction of the relevant Delivery Year, updated to reflect the Short-term Resource Procurement Target applicable to the relevant Incremental Auction and any change in the Reliability Requirement from the Base Residual Auction to such Incremental Auction.

2.69B Updated VRR Curve Increment

"Updated VRR Curve Increment" shall mean the portion of the Updated VRR Curve to the right of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.69C Updated VRR Curve Decrement

"Updated VRR Curve Decrement" shall mean the portion of the Updated VRR Curve to the left of a vertical line at the level of Unforced Capacity on the x-axis of such curve equal to the net

Unforced Capacity committed to the PJM Region as a result of all prior auctions conducted for such Delivery Year.

2.70 Variable Resource Requirement Curve

"Variable Resource Requirement Curve" shall mean a series of maximum prices that can be cleared in a Base Residual Auction for Unforced Capacity, corresponding to a series of varying resource requirements based on varying installed reserve margins, as determined by the Office of the Interconnection for the PJM Region and for certain Locational Deliverability Areas in accordance with the methodology provided in Section 5.

2.71 Zonal Capacity Price

"Zonal Capacity Price" shall mean the clearing price required in each Zone to meet the demand for Unforced Capacity and satisfy Locational Deliverability Requirements for the LDA or LDAs associated with such Zone. If the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA.

3. RESPONSIBILITIES OF THE OFFICE OF THE INTERCONNECTION

3.1 Support for Self-Supply and Bilateral Transactions

The Office of the Interconnection shall:

(a) support electronic tools to facilitate communication by Market Sellers and Market Buyers of information to the Office of the Interconnection concerning Self-Supply arrangements;

(b) support an electronic bulletin board providing a forum for prospective buyers and sellers to transact Capacity Resources outside the Reliability Pricing Model Auctions, including Locational UCAP transactions (including mechanisms to allow prospective Sellers with partial-year resources to explore voluntary opportunities to combine their resources such that they can be offered together for a full Delivery Year) and support electronic tools to report bilateral capacity transactions between Market Participants to the Office of the Interconnection, in accordance with procedures set forth in the PJM Manuals; and

(c) define one or more capacity trading hubs and determine and publicize values for such hubs based on the capacity prices determined for one or more Locational Deliverability Areas, in accordance with the PJM Manuals.

3.2 Administration of the Base Residual Auction and Incremental Auctions

The Office of the Interconnection shall conduct and administer the Base Residual Auction and Incremental Auctions in accordance with this Attachment, the Operating Agreement, and the Reliability Assurance Agreement. Administration of the Base Residual Auction and Incremental Auctions shall include, but not be limited to, the following:

a) Determining the qualification of entities to become Capacity Market Sellers and Capacity Market Buyers;

b) Determining PJM Region Peak Load Forecasts and Locational Deliverability Area Reliability Requirements;

c) Determining the Minimum Annual Resource Requirements and the Minimum Extended Summer Resource Requirements for the PJM Region and applicable LDAs for Delivery Years starting June 1, 2014 and ending May 31, 2017;

d) Determining Limited Resource Constraints and Sub-Annual Resource Constraints for Delivery Years starting June 1, 2017;

e) Determining the need, if any, for a Conditional Incremental Auction and providing appropriate prior notice of any such auction

f) Calculating the EFORd for each Generation Capacity Resource in the PJM Region to be used in the Third Incremental Auction;

g) Receiving Buy Bids and Sell Offers, determining Locational Deliverability Requirements and Variable Resource Requirement Curves, and determining the clearing price that reflects all such inputs;

h) Conducting settlements for auction transactions, including but not limited to rendering bills to, receiving payments from, and disbursing payments to, participants in Base Residual Auctions and Incremental Auctions.

i) Maintaining such records of Sell Offers and Buy Bids, clearing price determinations, and other aspects of auction transactions, as may be appropriate to the administration of Base Residual Auctions and Incremental Auctions; and

j) Posting of selected non-confidential data used in Reliability Pricing Model Auctions to calculate clearing prices and other auction results, as appropriate to inform market participants of auction conditions.

3.3 Records and Reports

The Office of the Interconnection shall prepare and maintain such records as are required for the administration of the Base Residual Auction and Incremental Auctions. For each auction conducted, the Office of the Interconnection shall, consistent with section 18.17 of the Operating Agreement, publish the following: (i) Zonal Capacity Prices for each LDA; (ii) Capacity Resource Clearing Prices for each LDA; (iii) Locational Price Adders; (iv) the total megawatts of Unforced Capacity that cleared; and (v) such other auction data as may be appropriate to the efficient and competitive conduct of the Base Residual Auction and Incremental Auctions. Such information shall be available on the PJM internet site through the end of the Delivery Year to which such auctions apply.

3.4 Counterparty

(a) PJMSettlement shall be the Counterparty to the transactions arising from the cleared Base Residual Auctions and Incremental Auctions; provided, however, PJMSettlement shall not be a contracting party to (i) any bilateral transactions between Market Participants, or (ii) with respect to Self-Supply for which designation of Self-Supply has been reported to the Office of the Interconnection.

(b) Charges. PJMSettlement shall be the Counterparty with respect to the obligations to pay, and the payment of, charges pursuant to this Attachment DD.

5.10 Auction Clearing Requirements

The Office of the Interconnection shall clear each Base Residual Auction and Incremental Auction for a Delivery Year in accordance with the following:

a) Variable Resource Requirement Curve

The Office of the Interconnection shall determine Variable Resource Requirement Curves for the PJM Region and for such Locational Deliverability Areas as determined appropriate in accordance with subsection (a)(iii) for such Delivery Year to establish the level of Capacity Resources that will provide an acceptable level of reliability consistent with the Reliability Principles and Standards. It is recognized that the variable resource requirement reflected in the Variable Resource Requirement Curve can result in an optimized auction clearing in which the level of Capacity Resources committed for a Delivery Year exceeds the PJM Region Reliability Requirement (less the Short-Term Resource Procurement Target) or Locational Deliverability Area Reliability Requirement (less the Short-Term Resource Procurement Target for the Zones associated with such LDA) for such Delivery Year. For any auction, the Updated Forecast Peak Load, and Short-Term Resource Procurement Target applicable to such auction, shall be used, and Price Responsive Demand from any applicable approved PRD Plan, including any associated PRD Reservation Prices, shall be reflected in the derivation of the Variable Resource Requirement Curves, in accordance with the methodology specified in the PJM Manuals.

i) Methodology to Establish the Variable Resource Requirement Curve

Prior to the Base Residual Auction, in accordance with the schedule in the PJM Manuals, the Office of the Interconnection shall establish the Variable Resource Requirement Curve for the PJM Region as follows:

- Each Variable Resource Requirement Curve shall be plotted on a graph on which Unforced Capacity is on the x-axis and price is on the y-axis;

- The Variable Resource Requirement Curve for the PJM Region shall be plotted by first combining (i) a horizontal line from the y-axis to point (1), (ii) a straight line connecting points (1) and (2), (iii) a straight line connecting points (2) and (3), and (iv) a vertical line from point (3) to the x-axis, where:

    - For point (1), price equals: {the greater of [the Cost of New Entry] or [1.5 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)]} divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus the approved PJM Region Installed Reserve Margin ("IRM")% minus 3%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

- For point (2), price equals: (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset) divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 1%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target; and

- For point (3), price equals [0.2 times (the Cost of New Entry minus the Net Energy and Ancillary Service Revenue Offset)] divided by (one minus the pool-wide average EFORd) and Unforced Capacity equals: [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 5%) divided by (100% plus IRM%)] minus the Short-Term Resource Procurement Target;

ii) For any Delivery Year, the Office of the Interconnection shall establish a separate Variable Resource Requirement Curve for each LDA for which:

A. the Capacity Emergency Transfer Limit is less than 1.15 times the Capacity Emergency Transfer Objective, as determined by the Office of the Interconnection in accordance with NERC and Applicable Regional Entity guidelines; or

B. such LDA had a Locational Price Adder in any one or more of the three immediately preceding Base Residual Auctions; or

C. such LDA is determined in a preliminary analysis by the Office of the Interconnection to be likely to have a Locational Price Adder, based on historic offer price levels; provided however that for the Base Residual Auction conducted for the Delivery Year commencing on June 1, 2012, the Eastern Mid-Atlantic Region ("EMAR"), Southwest Mid-Atlantic Region ("SWMAR"), and Mid-Atlantic Region ("MAR") LDAs shall employ separate Variable Resource Requirement Curves regardless of the outcome of the above three tests; and provided further that the Office of the Interconnection may establish a separate Variable Resource Requirement Curve for an LDA not otherwise qualifying under the above three tests if it finds that such is required to achieve an acceptable level of reliability consistent with the Reliability Principles and Standards, in which case the Office of the Interconnection shall post such finding, such LDA, and such Variable Resource Requirement Curve on its internet site no later than the March 31 last preceding the Base Residual Auction for such Delivery Year. The same process as set forth in subsection (a)(i) shall be used to establish the Variable Resource Requirement Curve for any such LDA, except that the Locational Deliverability Area Reliability Requirement for such LDA shall be substituted for the PJM Region Reliability Requirement and the LDA Short-Term Resource Procurement Target shall be substituted for the PJM Region Short-Term Resource Procurement Target. For purposes of calculating the Capacity Emergency

Transfer Limit under this section, all generation resources located in the PJM Region that are, or that qualify to become, Capacity Resources, shall be modeled at their full capacity rating, regardless of the amount of capacity cleared from such resource for the immediately preceding Delivery Year.

iii) Procedure for ongoing review of Variable Resource Requirement Curve shape.

Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall perform a review of the shape of the Variable Resource Requirement Curve, as established by the requirements of the foregoing subsection. Such analysis shall be based on simulation of market conditions to quantify the ability of the market to invest in new Capacity Resources and to meet the applicable reliability requirements on a probabilistic basis. Based on the results of such review, PJM shall prepare a recommendation to either modify or retain the existing Variable Resource Requirement Curve shape. The Office of the Interconnection shall post the recommendation and shall review the recommendation through the stakeholder process to solicit stakeholder input. If a modification of the Variable Resource Requirement Curve shape is recommended, the following process shall be followed:

A) If the Office of the Interconnection determines that the Variable Resource Requirement Curve shape should be modified, Staff of the Office of the Interconnection shall propose a new Variable Resource Requirement Curve shape on or before July 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

B) The PJM Members shall review the proposed modification to the Variable Resource Requirement Curve shape.

C) The PJM Members shall either vote to (i) endorse the proposed modification, (ii) propose alternate modifications or (iii) recommend no modification, by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) The PJM Board of Managers shall consider a proposed modification to the Variable Resource Requirement Curve shape, and the Office of the Interconnection shall file any approved modified Variable Resource Requirement Curve shape with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

iv) Cost of New Entry

A) For the Delivery Year commencing on June 1, 2015, and continuing thereafter unless and until changed pursuant to subsection (B) below, the Cost of New Entry for the PJM Region shall be $128,000 per MW-year. The Cost of New Entry for each LDA shall be determined based upon the Transmission Owner zones that comprise such LDA, as provided in the table below. If an LDA combines transmission zones with differing Cost of New Entry values, the lowest such value shall be used.

Geographic Location Within the PJM Region Encompassing These Zones	**Cost of New Entry in $/MW-Year**
PS, JCP&L, AE, PECO, DPL, RECO ("CONE Area 1")	140,000
BGE, PEPCO ("CONE Area 2")	130,600
AEP, Dayton, ComEd, APS, DQL, ATSI, DEOK, EKPC ("CONE Area 3")	127,500
PPL, MetEd, Penelec ("CONE Area 4")	134,500
Dominion ("CONE Area 5")	114,500

B) Beginning with the 2016-2017 Delivery Year, the CONE shall be adjusted to reflect changes in generating plant construction costs based on changes in the Applicable H-W Index, in accordance with the following:

(1) The Applicable H-W Index for any Delivery Year shall be the most recently published twelve-month change, at the time CONE values are required to be posted for the Base Residual Auction for such Delivery Year, in the Total Other Production Plant Index shown in the Handy-Whitman Index of Public Utility Construction Costs for the North Atlantic Region for purposes of CONE Areas 1, 2, and 4, for the North Central Region for purposes of CONE Area 3, and for the South Atlantic Region for purposes of CONE Area 5.

(2) The CONE in a CONE Area shall be adjusted prior to the Base Residual Auction for each Delivery Year by applying the Applicable H-W Index for such CONE Area to the Benchmark CONE for such CONE Area.

(3) The Benchmark CONE for a CONE Area shall be the CONE used for such CONE Area in the Base Residual Auction for the prior Delivery Year (provided, however that the Gross CONE values stated in subsection (a)(iv)(A) above shall be the Benchmark CONE values for the 2015-2016 Delivery Year to which the Applicable H-W Index shall be applied to determine the CONE for subsequent Delivery Years).

(4) Notwithstanding the foregoing, CONE values for any CONE Area for any Delivery Year shall be subject to amendment pursuant to appropriate filings with FERC under

the Federal Power Act, including, without limitation, any filings resulting from the process described in section 5.10(a)(vii)(C) or any filing to establish new or revised CONE Areas.

v) Net Energy and Ancillary Services Revenue Offset

A) The Office of the Interconnection shall determine the Net Energy and Ancillary Services Revenue Offset each year for the PJM Region as (A) the annual average of the revenues that would have been received by the Reference Resource from the PJM energy markets during a period of three consecutive calendar years preceding the time of the determination, based on (1) the heat rate and other characteristics of such Reference Resource; (2) fuel prices reported during such period at an appropriate pricing point for the PJM Region with a fuel transmission adder appropriate for such region, as set forth in the PJM Manuals, assumed variable operation and maintenance expenses for such resource of $6.47 per MWh, and actual PJM hourly average Locational Marginal Prices recorded in the PJM Region during such period; and (3) an assumption that the Reference Resource would be dispatched for both the Day-Ahead and Real-Time Energy Markets on a Peak-Hour Dispatch basis; plus (B) ancillary service revenues of $2,199 per MW-year.

B) The Office of the Interconnection also shall determine a Net Energy and Ancillary Service Revenue Offset each year for each sub-region of the PJM Region for which the Cost of New Entry is determined as identified above, using the same procedures and methods as set forth in the previous subsection; provided, however, that: (1) the average hourly LMPs for the Zone in which the Reference Resource was assumed to be installed for purposes of the CONE estimate (as specified in the PJM Manuals) shall be used in place of the PJM Region average hourly LMPs; (2) if such sub-region was not integrated into the PJM Region for the entire applicable period, then the offset shall be calculated using only those whole calendar years during which the sub-region was integrated; and (3) a posted fuel pricing point in such sub-region, if available, and (if such pricing point is not available) a fuel transmission adder appropriate to each assumed Cost of New Entry location from an appropriate PJM Region pricing point shall be used for each such sub-region.

vi) Process for Establishing Parameters of Variable Resource Requirement Curve

A) The parameters of the Variable Resource Requirement Curve will be established prior to the conduct of the Base Residual Auction

for a Delivery Year and will be used for such Base Residual Auction.

B) The Office of the Interconnection shall determine the PJM Region Reliability Requirement and the Locational Deliverability Area Reliability Requirement for each Locational Deliverability Area for which a Variable Resource Requirement Curve has been established for such Base Residual Auction on or before February 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values will be applied, in accordance with the Reliability Assurance Agreement.

C) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the calculation of the Cost of New Entry for each CONE Area.

1) If the Office of the Interconnection determines that the Cost of New Entry values should be modified, the Staff of the Office of the Interconnection shall propose new Cost of New Entry values on or before July 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

2) The PJM Members shall review the proposed values.

3) The PJM Members shall either vote to (i) endorse the proposed values, (ii) propose alternate values or (iii) recommend no modification, by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

4) The PJM Board of Managers shall consider Cost of New Entry values, and the Office of the Interconnection shall file any approved modified Cost of New Entry values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

D) Beginning with the Delivery Year that commences June 1, 2018, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the methodology set forth in this Attachment for determining the Net Energy and Ancillary Services Revenue Offset for the PJM Region and for each Zone.

1) If the Office of the Interconnection determines that the Net Energy and Ancillary Services Revenue Offset methodology should be modified, Staff of the Office of the Interconnection shall propose a new Net Energy and Ancillary Services Revenue Offset methodology on or before July 15, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

2) The PJM Members shall review the proposed methodology.

3) The PJM Members shall either vote to (i) endorse the proposed methodology, (ii) propose an alternate methodology or (iii) recommend no modification, by October 31, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new methodology would be applied.

4) The PJM Board of Managers shall consider the Net Revenue Offset methodology, and the Office of the Interconnection shall file any approved modified Net Energy and Ancillary Services Revenue Offset values with the FERC by December 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

b) Locational Requirements

The Office of Interconnection shall establish locational requirements prior to the Base Residual Auction to quantify the amount of Unforced Capacity that must be committed in each Locational Deliverability Area, in accordance with the PJM Reliability Assurance Agreement.

c) Resource Requirements and Constraints

Prior to the Base Residual Auction and each Incremental Auction for the Delivery Years starting on June 1, 2014 and ending May 31, 2017, the Office of the Interconnection shall establish the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year. Prior to the Base Residual Auction and Incremental Auctions for each Delivery Year beginning with the Delivery Year that commences June 1, 2017, the Office of the Interconnection shall establish the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which the Office of the Interconnection is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year.

d) Preliminary PJM Region Peak Load Forecast for the Delivery Year

The Office of the Interconnection shall establish the Preliminary PJM Region Load Forecast for the Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the Base Residual Auction for such Delivery Year.

e) Updated PJM Region Peak Load Forecasts for Incremental Auctions

The Office of the Interconnection shall establish the updated PJM Region Peak Load Forecast for a Delivery Year in accordance with the PJM Manuals by February 1, prior to the conduct of the First, Second, and Third Incremental Auction for such Delivery Year.

5.11 Posting of Information Relevant to the RPM Auctions

a) In accordance with the schedule provided in the PJM Manuals, PJM will post the following information for a Delivery Year prior to conducting the Base Residual Auction for such Delivery Year:

i) The Preliminary PJM Region Peak Load Forecast (for the PJM Region, and allocated to each Zone);

ii) The PJM Region Installed Reserve Margin, the Pool-wide average EFORd, the Forecast Pool Requirement*, and all applicable Capacity Import Limits*;

iii) The Demand Resource Factor;

iv) The PJM Region Reliability Requirement, and the Variable Resource Requirement Curve for the PJM Region, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices;

v) The Locational Deliverability Area Reliability Requirement and the Variable Resource Requirement Curve for each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction, including the details of any adjustments to account for Price Responsive Demand and any associated PRD Reservation Prices, and the CETO and CETL values for all Locational Deliverability Areas;

vi) For the Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year; and for the Delivery Year that commences June 1, 2017 and subsequent Delivery Years, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which PJM is required under section 5.10(a) of this Attachment DD to establish a separate VRR Curve for such Delivery Year;

vii) Any Transmission Upgrades that are expected to be in service for such Delivery Year, provided that a Transmission Upgrade that is Backbone Transmission satisfies the project development milestones set forth in section 5.11A;

viii) The bidding window time schedule for each auction to be conducted for such Delivery Year; and

ix) The Net Energy and Ancillary Services Revenue Offset values for the PJM Region for use in the Variable Resource Requirement Curves for the PJM Region and each Locational Deliverability Area for which a separate Variable Resource Requirement Curve has been established for such Base Residual Auction.

b) In addition to the information required to be posted by subsection (a), PJM will post for a Delivery Year, at least sixty (60) days prior to conducting the Base Residual Auction for such Delivery Year, the aggregate megawatt quantity of, for the PJM Region, all Self-Supply Exemption requests under section 5.14(h), all Competitive Entry Exemption requests under section 5.14(h), and such exemptions granted in each such category, and to the extent PJM has made any such determination, notice that PJM has determined that one or more state-sponsored or state-mandated procurement processes is Competitive and Non-Discriminatory pursuant to section 5.14(h).

c) The information listed in (a) will be posted and applicable for the First, Second, Third, and Conditional Incremental Auctions for such Delivery Year, except to the extent updated or adjusted as required by other provisions of this Tariff.

d) In accordance with the schedule provided in the PJM Manuals, PJM will post the Final PJM Region Peak Load Forecast and the allocation to each zone of the obligation resulting from such final forecast, following the completion of the final Incremental Auction (including any Conditional Incremental Auction) conducted for such Delivery Year;

e) In accordance with the schedule provided in the PJM Manuals, PJM will advise owners of Generation Capacity Resources of the updated EFORd values for such Generation Capacity Resources prior to the conduct of the Third Incremental Auction for such Delivery Year.

f) After conducting the Reliability Pricing Model Auctions, PJM will post the results of each auction as soon thereafter as possible, including any adjustments to PJM Region or LDA Reliability Requirements to reflect Price Responsive Demand with a PRD Reservation Price equal to or less than the applicable Base Residual Auction clearing price. The posted results shall include graphical supply curves that are (a) provided for the entire PJM Region, (b) provided for any Locational Deliverability Area for which there are four (4) or more suppliers, and (c) developed using a formulaic approach to smooth the curves using a statistical technique that fits a smooth curve to the underlying supply curve data while ensuring that the point of intersection between supply and demand curves is at the market clearing price. At such time, PJM also shall post the aggregate megawatt quantity requested and granted in the Self-Supply and Competitive Entry Exemption categories in the EMAAC, MAAC and Rest of RTO LDAs/regions; the aggregate megawatt quantity cleared in the RPM Auction for Self-Supply and Competitive Entry Exemption categories; and the aggregate megawatt quantity of Self-Supply and Competitive Entry Exemptions requested and granted for any LDA other than those specified in the preceding clause if the LDA has more than four new generation projects in the generation interconnection queue that could have offered into the applicable RPM Auction and the LDA had a separate VRR Curve posted for the applicable RPM Auction.

If PJM discovers an error in the initial posting of auction results for a particular Reliability Pricing Model Auction, it shall notify Market Participants of the error as soon as possible after it is found, but in no event later than 5:00 p.m. of the fifth business day following the initial publication of the results of the auction. After this initial notification, if PJM determines it is necessary to post modified results, it shall provide notification of its intent to do so, together with

all available supporting documentation, by no later than 5:00 p.m. of the seventh business day following the initial publication of the results of the auction. Thereafter, PJM must post on its Web site any corrected auction results by no later than 5:00 p.m. of the tenth business day following the initial publication of the results of the auction. Should any of the above deadlines pass without the associated action on the part of the Office of the Interconnection, the originally posted results will be considered final. Notwithstanding the foregoing, the deadlines set forth above shall not apply if the referenced auction results are under publicly noticed review by the FERC.

5.12 Conduct of RPM Auctions

The Office of the Interconnection shall employ an optimization algorithm for each Base Residual Auction and each Incremental Auction to evaluate the Sell Offers and other inputs to such auction to determine the Sell Offers that clear such auction.

a) Base Residual Auction

For each Base Residual Auction, the optimization algorithm shall consider:

- all Sell Offers submitted in such auction;
- the Variable Resource Requirement Curves for the PJM Region and each LDA;
- any constraints resulting from the Locational Deliverability Requirement *and any applicable Capacity Import Limit*;
- for Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD; and for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, the Limited Resource Constraints and the Sub-Annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;
- the PJM Region Reliability Requirement minus the Short-Term Resource Procurement Target.

The optimization algorithm shall be applied to calculate the overall clearing result to minimize the cost of satisfying the reliability requirements across the PJM Region, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, while respecting all applicable requirements and constraints, including any restrictions specified in any Credit-Limited Offers. Where the supply curve formed by the Sell Offers submitted in an auction falls entirely below the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all such Sell Offers. Where the supply curve consists only of Sell Offers located entirely below the Variable Resource Requirement Curve and Sell Offers located entirely above the Variable Resource Requirement Curve, the auction shall clear at the price-capacity point on the Variable Resource Requirement Curve corresponding to the total Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve. In determining the lowest-cost overall clearing result that satisfies all applicable constraints and requirements, the optimization may select from among multiple

possible alternative clearing results that satisfy such requirements, including, for example (without limitation by such example), accepting a lower-priced Sell Offer that intersects the Variable Resource Requirement Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the Variable Resource Requirement Curve and that contains no minimum-block limitations, or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the Variable Resource Requirement Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the Variable Resource Requirement Curve.

The Sell Offer price of a Qualifying Transmission Upgrade shall be treated as a capacity price differential between the LDAs specified in such Sell Offer between which CETL is increased, and the Import Capability provided by such upgrade shall clear to the extent the difference in clearing prices between such LDAs is greater than the price specified in such Sell Offer. The Capacity Resource clearing results and Capacity Resource Clearing Prices so determined shall be applicable for such Delivery Year.

b) Scheduled Incremental Auctions

For purposes of a Scheduled Incremental Auction, the optimization algorithm shall consider:

- The PJM Region Reliability Requirement, less the Short-term Resource Procurement Target;
- Updated LDA Reliability Requirements taking into account any updated Capacity Emergency Transfer Objectives;
- The Capacity Emergency Transfer Limit used in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction;
- *All applicable Capacity Import Limits;*
- For each LDA, such LDA's updated Reliability Requirement, less such LDA's Short-Term Resource Procurement Target;
- For Delivery Years starting June 1, 2014 and ending May 31, 2017, the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement for the PJM Region and for each LDA for which PJM is required to establish a separate VRR Curve for the Base Residual Auction for the relevant Delivery Year; and for the Delivery Year commencing June 1, 2017 and subsequent Delivery Years, the Limited Resource Constraints and the Sub-annual Resource Constraints for the PJM Region and for each Locational Deliverability Area for which a separate VRR Curve is required by section 5.10(a) of this Attachment DD;

- A demand curve consisting of the Buy Bids submitted in such auction and, if indicated for use in such auction in accordance with the provisions below, the Updated VRR Curve Increment;

- The Sell Offers submitted in such auction; and

- The Unforced Capacity previously committed for such Delivery Year.

(i) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(2) of this Attachment, the Office of the Interconnection shall employ in the clearing of such auction the Updated VRR Curve Increment.

(ii) When the requirement to seek additional resource commitments in a Scheduled Incremental Auction is triggered by section 5.4(c)(1) of this Attachment, and the conditions stated in section 5.4(c)(2) do not apply, the Office of the Interconnection first shall determine the total quantity of (A) the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (C) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (D) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year plus any amount required by section 5.4(c)(2)(ii). If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iii) When the possible need to seek agreements to release capacity commitments in any Scheduled Incremental Auction is indicated for the PJM Region or any LDA by section 5.4(c)(3)(i) of this Attachment, the Office of the Interconnection first shall determine the total quantity of (A) the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (C) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, plus (D) the difference between the updated PJM Region Reliability Requirement or updated LDA Reliability Requirement and, respectively, the PJM Region Reliability Requirement, or LDA Reliability Requirement, utilized in the most recent prior auction conducted for such Delivery Year minus any capacity sell-back amount determined by PJM to be required for the PJM Region or such LDA by section 5.4(c)(3)(ii) of this Attachment; provided, however, that the

amount sold in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade may not exceed the amounts purchased in total for all LDAs and the PJM Region related to a delay in a Backbone Transmission upgrade. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity.

(iv) If none of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection first shall determine the total quantity of (A) the Short-Term Resource Procurement Target Applicable Share for such auction, plus (B) the amount that the Office of the Interconnection sought to procure in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction, minus (C) the amount that the Office of the Interconnection sought to sell back in prior Scheduled Incremental Auctions for such Delivery Year that does not clear such auction. If the result of such equation is a positive quantity, the Office of the Interconnection shall employ in the clearing of such auction a portion of the Updated VRR Curve Increment extending right from the left-most point on that curve in a megawatt amount equal to that positive quantity defined above, to seek to procure such quantity. If the result of such equation is a negative quantity, the Office of the Interconnection shall employ in the clearing of the auction a portion of the Updated VRR Curve Decrement, extending and ascending to the left from the right-most point on that curve in a megawatt amount corresponding to the negative quantity defined above, to seek to sell back such quantity. If more than one of the tests for adjustment of capacity procurement in subsections (i), (ii), or (iii) is satisfied for the PJM Region or an LDA in a Scheduled Incremental Auction, the Office of the Interconnection shall not seek to procure the Short-Term Resource Procurement Target Applicable Share more than once for such region or area for such auction.

(v) If PJM seeks to procure additional capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years due to a triggering of the tests in subsections (i), (ii), (iii) or (iv) then the Minimum Annual Resource Requirement for such Auction will be equal to the updated Minimum Annual Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity from Annual Resources, and the Minimum Extended Summer Resource Requirement for such Auction will be equal to the updated Minimum Extended Summer Resource Requirement (based on the latest DR Reliability Targets) minus the amount of previously committed capacity in an Incremental Auction for the 2014-15, 2015-16 or 2016-17 Delivery Years from Annual Resources and Extended Summer Demand Resources. If PJM seeks to release prior committed capacity due to a triggering of the test in subsection (iii) then PJM may not release prior committed capacity from Annual Resources or Extended Summer Demand Resources below the updated Minimum Annual Resource Requirement and updated Minimum Extended Summer Resource Requirement, respectively.

(vi) If the above tests are triggered for an LDA and for another LDA wholly located within the first LDA, the Office of the Interconnection may adjust the amount of any Sell Offer or Buy Bids otherwise required by subsections (i), (ii), or (iii) above in one LDA as appropriate to take into account any reliability impacts on the other LDA.

(vii) The optimization algorithm shall calculate the overall clearing result to minimize the cost to satisfy the Unforced Capacity Obligation of the PJM Region to account for the updated PJM Peak Load Forecast and the cost of committing replacement capacity in response to the Buy Bids submitted, while satisfying or honoring such reliability requirements and constraints, in the same manner as set forth in subsection (a) above.

(viii) Load Serving Entities may be entitled to certain credits ("Excess Commitment Credits") under certain circumstances as follows:

(A) For either or both of the Delivery Years commencing on June 1, 2010 or June 1, 2011, if the PJM Region Reliability Requirement used for purposes of the Base Residual Auction for such Delivery Year exceeds the PJM Region Reliability Requirement that is based on the last updated load forecast prior to such Delivery Year, then such excess will be allocated to Load Serving Entities as set forth below;

(B) For any Delivery Year beginning with the Delivery Year that commences June 1, 2012, the total amount that the Office of the Interconnection sought to sell back pursuant to subsection (b)(iii) above in the Scheduled Incremental Auctions for such Delivery Year that does not clear such auctions, less the total amount that the Office of the Interconnection sought to procure pursuant to subsections (b)(i) and (b)(ii) above in the Scheduled Incremental Auctions for such Delivery Years that does not clear such auctions, will be allocated to Load Serving Entities as set forth below;

(C) the amount from (A) or (B) above for the PJM Region shall be allocated among Locational Deliverability Areas pro rata based on the reduction for each such Locational Deliverability Area in the peak load forecast from the time of the Base Residual Auction to the time of the Third Incremental Auction; provided, however, that the amount allocated to a Locational Deliverability Area may not exceed the reduction in the corresponding Reliability Requirement for such Locational Deliverability Area; and provided further that any LDA with an increase in its load forecast shall not be allocated any Excess Commitment Credits;

(D) the amount, if any, allocated to a Locational Deliverability Area shall be further allocated among Load Serving Entities in such areas that are

charged a Locational Reliability Charge based on the Daily Unforced Capacity Obligation of such Load Serving Entities as of June 1 of the Delivery Year and shall be constant for the entire Delivery Year. Excess Commitment Credits may be used as Replacement Capacity or traded bilaterally.

c) Conditional Incremental Auction

For each Conditional Incremental Auction, the optimization algorithm shall consider:

- The quantity and location of capacity required to address the identified reliability concern that gave rise to the Conditional Incremental Auction;
- *All applicable Capacity Import Limits;*
- the same Capacity Emergency Transfer Limits that were modeled in the Base Residual Auction, or any updated value resulting from a Conditional Incremental Auction; and
- the Sell Offers submitted in such auction.

The Office of the Interconnection shall submit a Buy Bid based on the quantity and location of capacity required to address the identified reliability violation at a Buy Bid price equal to 1.5 times Net CONE.

The optimization algorithm shall calculate the overall clearing result to minimize the cost to address the identified reliability concern, while satisfying or honoring such reliability requirements and constraints.

d) Equal-priced Sell Offers

If two or more Sell Offers submitted in any auction satisfying all applicable constraints include the same offer price, and some, but not all, of the Unforced Capacity of such Sell Offers is required to clear the auction, then the auction shall be cleared in a manner that minimizes total costs, including total make-whole payments if any such offer includes a minimum block and, to the extent consistent with the foregoing, in accordance with the following additional principles:

1) as necessary, the optimization shall clear such offers that have a flexible megawatt quantity, and the flexible portions of such offers that include a minimum block that already has cleared, where some but not all of such equal-priced flexible quantities are required to clear the auction, pro rata based on their flexible megawatt quantities; and

2) when equal-priced minimum-block offers would result in equal overall costs, including make-whole payments, and only one such offer is required to clear the auction, then the offer that was submitted earliest to the Office of the Interconnection, based on its assigned timestamp, will clear.

5.14 Clearing Prices and Charges

a) Capacity Resource Clearing Prices

For each Base Residual Auction and Incremental Auction, the Office of the Interconnection shall calculate a clearing price to be paid for each megawatt-day of Unforced Capacity that clears in such auction. The Capacity Resource Clearing Price for each LDA will be the marginal value of system capacity for the PJM Region, without considering locational constraints, adjusted as necessary by any applicable Locational Price Adders, Annual Resource Price Adders, Extended Summer Resource Price Adders, Limited Resource Price Decrements, and Sub-Annual Resource Price Decrements, all as determined by the Office of the Interconnection based on the optimization algorithm. If a Capacity Resource is located in more than one Locational Deliverability Area, it shall be paid the highest Locational Price Adder in any applicable LDA in which the Sell Offer for such Capacity Resource cleared. The Annual Resource Price Adder is applicable for Annual Resources only. The Extended Summer Resource Price Adder is applicable for Annual Resources and Extended Summer Demand Resources.

b) Resource Make-Whole Payments

If a Sell Offer specifies a minimum block, and only a portion of such block is needed to clear the market in a Base Residual or Incremental Auction, the MW portion of such Sell Offer needed to clear the market shall clear, and such Sell Offer shall set the marginal value of system capacity. In addition, the Capacity Market Seller shall receive a Resource Make-Whole Payment equal to the Capacity Resource Clearing Price in such auction times the difference between the Sell Offer's minimum block MW quantity and the Sell Offer's cleared MW quantity. The cost for any such Resource Make-Whole Payments required in a Base Residual Auction or Incremental Auction for adjustment of prior capacity commitments shall be collected pro rata from all LSEs in the LDA in which such payments were made, based on their Daily Unforced Capacity Obligations. The cost for any such Resource Make-Whole Payments required in an Incremental Auction for capacity replacement shall be collected from all Capacity Market Buyers in the LDA in which such payments were made, on a pro-rata basis based on the MWs purchased in such auction.

c) New Entry Price Adjustment

A Capacity Market Seller that submits a Sell Offer based on a Planned Generation Capacity Resource that clears in the BRA for a Delivery Year may, at its election, submit Sell Offers with a New Entry Price Adjustment in the BRAs for the two immediately succeeding Delivery Years if:

1. Such Capacity Market Seller provides notice of such election at the time it submits its Sell Offer for such resource in the BRA for the first Delivery Year for which such resource is eligible to be considered a Planned Generation Capacity Resource. When the Capacity Market Seller provides notice of such election, it must specify whether its Sell Offer is contingent upon qualifying for the New Entry Price Adjustment. The Office of the Interconnection shall not clear such contingent Sell Offer if it does not qualify for the New Entry Price Adjustment.

2. All or any part of a Sell Offer from the Planned Generation Capacity Resource submitted in accordance with section 5.14(c)(1) is the marginal Sell Offer that sets the Capacity Resource Clearing Price for the LDA.

3. Acceptance of all or any part of a Sell Offer that meets the conditions in section 5.14(c)(1)-(2) in the BRA increases the total Unforced Capacity committed in the BRA (including any minimum block quantity) for the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement, minus the Short Term Resource Procurement Target, to a megawatt quantity at or above a megawatt quantity at the price-quantity point on the VRR Curve at which the price is 0.40 times the applicable Net CONE divided by (one minus the pool-wide average EFORd).

4. Such Capacity Market Seller submits Sell Offers in the BRA for the two immediately succeeding Delivery Years for the entire Unforced Capacity of such Generation Capacity Resource committed in the first BRA under section 5.14(c)(1)-(2) equal to the lesser of: A) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource that satisfies the conditions in section 5.14(c)(1)-(3); or B) 0.90 times the Net CONE applicable in the first BRA in which such Planned Generation Capacity Resource meeting the conditions in section 5.14(c)(1)-(3) cleared, on an Unforced Capacity basis, for such LDA.

5. If the Sell Offer is submitted consistent with section 5.14(c)(1)-(4) the foregoing conditions, then:

(i) in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all cleared resources in the LDA receive the Capacity Resource Clearing Price set by the Sell Offer as the marginal offer, in accordance with sections 5.12(a) and 5.14(a).

(ii) in either of the subsequent two BRAs, if any part of the Sell Offer from the Resource clears, it shall receive the Capacity Resource Clearing Price for such LDA for its cleared capacity and for any additional minimum block quantity pursuant to section 5.14(b); or

(iii) if the Resource does not clear, it shall be deemed resubmitted at the highest price per MW-day at which the megawatt quantity of Unforced Capacity of such Resource that cleared the first-year BRA will clear the subsequent-year BRA pursuant to the optimization algorithm described in section 5.12(a) of this Attachment, and

(iv) the resource with its Sell Offer submitted shall clear and shall be committed to the PJM Region in the amount cleared, plus any additional minimum-block quantity from its Sell Offer for such Delivery Year, but such additional amount shall be no greater than the portion of a minimum-block quantity, if any, from its first-year Sell Offer satisfying section

5.14(c)(1)-(3) that is entitled to compensation pursuant to section 5.14(b) of this Attachment; and

(v) the Capacity Resource Clearing Price, and the resources cleared, shall be re-determined to reflect the resubmitted Sell Offer. In such case, the Resource for which the Sell Offer is submitted pursuant to section 5.14(c)(1)-(4) shall be paid for the entire committed quantity at the Sell Offer price that it initially submitted in such subsequent BRA. The difference between such Sell Offer price and the Capacity Resource Clearing Price (as well as any difference between the cleared quantity and the committed quantity), will be treated as a Resource Make-Whole Payment in accordance with Section 5.14(b). Other capacity resources that clear the BRA in such LDA receive the Capacity Resource Clearing Price as determined in Section 5.14(a).

6. The failure to submit a Sell Offer consistent with Section 5.14(c)(i)-(iii) in the BRA for Delivery Year 3 shall not retroactively revoke the New Entry Price Adjustment for Delivery Year 2. However, the failure to submit a Sell Offer consistent with section 5.14(c)(4) in the BRA for Delivery Year 2 shall make the resource ineligible for the New Entry Pricing Adjustment for Delivery Years 2 and 3.

7. For each Delivery Year that the foregoing conditions are satisfied, the Office of the Interconnection shall maintain and employ in the auction clearing for such LDA a separate VRR Curve, notwithstanding the outcome of the test referenced in Section 5.10(a)(ii) of this Attachment.

8. On or before August 1, 2012, PJM shall file with FERC under FPA section 205, as determined necessary by PJM following a stakeholder process, tariff changes to establish a long-term auction process as a not unduly discriminatory means to provide adequate long-term revenue assurances to support new entry, as a supplement to or replacement of this New Entry Price Adjustment.

d) Qualifying Transmission Upgrade Payments

A Capacity Market Seller that submitted a Sell Offer based on a Qualifying Transmission Upgrade that clears in the Base Residual Auction shall receive a payment equal to the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA into which the Qualifying Transmission Upgrade is to increase Capacity Emergency Transfer Limit, less the Capacity Resource Clearing Price, including any Locational Price Adder, of the LDA from which the upgrade was to provide such increased CETL, multiplied by the megawatt quantity of increased CETL cleared from such Sell Offer. Such payments shall be reflected in the Locational Price Adder determined as part of the Final Zonal Capacity Price for the Zone associated with such LDAs, and shall be funded through a reduction in the Capacity Transfer Rights allocated to Load-Serving Entities under section 5.15, as set forth in that section. PJMSettlement shall be the Counterparty to any cleared capacity transaction resulting from a Sell Offer based on a Qualifying Transmission Upgrade.

e) Locational Reliability Charge

In accordance with the Reliability Assurance Agreement, each LSE shall incur a Locational Reliability Charge (subject to certain offsets and other adjustments as described in sections 5.13, 5.14A, and 5.15) equal to such LSE's Daily Unforced Capacity Obligation in a Zone during such Delivery Year multiplied by the applicable Final Zonal Capacity Price in such Zone. PJMSettlement shall be the Counterparty to the LSEs' obligations to pay, and payments of, Locational Reliability Charges.

f) The Office of the Interconnection shall determine Zonal Capacity Prices in accordance with the following, based on the optimization algorithm:

i) The Office of the Interconnection shall calculate and post the Preliminary Zonal Capacity Prices for each Delivery Year following the Base Residual Auction for such Delivery Year. The Preliminary Zonal Capacity Price for each Zone shall be the sum of: 1) the marginal value of system capacity for the PJM Region, without considering locational constraints; 2) the Locational Price Adder, if any, for the LDA in which such Zone is located; provided however, that if the Zone contains multiple LDAs with different Capacity Resource Clearing Prices, the Zonal Capacity Price shall be a weighted average of the Capacity Resource Clearing Prices for such LDAs, weighted by the Unforced Capacity of Capacity Resources cleared in each such LDA; 3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources in the LDA for which the zone is located; 4) an adjustment, if required, to account for Resource Make-Whole Payments; and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits, all as determined in accordance with the optimization algorithm.

ii) The Office of the Interconnection shall calculate and post the Adjusted Zonal Capacity Price following each Incremental Auction. The Adjusted Zonal Capacity Price for each Zone shall equal the sum of: (1) the average marginal value of system capacity weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (2) the average Locational Price Adder weighted by the Unforced Capacity cleared in all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (3) an adjustment, if required, to account for adders paid to Annual Resources and Extended Summer Demand Resources for all auctions previously conducted for such Delivery Year (excluding any Unforced Capacity cleared as replacement capacity); (4) an adjustment, if required, to account for Resource Make-Whole Payments for all actions previously conducted (excluding any Resource Make-Whole Payments to be charged to the buyers of replacement capacity); and (5) an adjustment, if required to provide sufficient revenue for payment of any PRD Credits. The Adjusted Zonal Capacity Price may decrease if Unforced Capacity is decommitted or the Resource Clearing Price decreases in an Incremental Auction.

iii) The Office of the Interconnection shall calculate and post the Final Zonal Capacity Price for each Delivery Year after the final auction is held for such Delivery Year, as set forth above. The Final Zonal Capacity Price for each Zone shall equal the Adjusted Zonal Capacity Price, as further adjusted to reflect any decreases in the Nominated Demand Resource

Value of any existing Demand Resource cleared in the Base Residual Auction and Second Incremental Auction.

g) Resource Substitution Charge

Each Capacity Market Buyer in an Incremental Auction securing replacement capacity shall pay a Resource Substitution Charge equal to the Capacity Resource Clearing Price resulting from such auction multiplied by the megawatt quantity of Unforced Capacity purchased by such Market Buyer in such auction.

h) Minimum Offer Price Rule for Certain Generation Capacity Resources

(1) *General Rule.* Any Sell Offer submitted in any RPM Auction for any Delivery Year based on a MOPR Screened Generation Resource shall have an offer price no lower than the MOPR Floor Offer Price for the period specified in this subsection (h), unless the Capacity Market Seller has obtained a Self-Supply Exemption, a Competitive Entry Exemption, *or a Unit-Specific Exception* with respect to such MOPR Screened Generation Resource in such auction prior to the submission of such offer, in accordance with the provisions of this subsection. Nothing in subsection (c) of this section 5.14 shall be read to excuse compliance of any Sell Offer with the requirements of this subsection (h).

(2) *Applicability.* A MOPR Screened Generation Resource shall be any Generation Capacity Resource, and any uprate to a Generation Capacity Resource that is being, or has been, modified to increase the number of megawatts of available installed capacity thereof by 20 MW or more, based on a combustion turbine, combined cycle, or integrated gasification combined cycle generating plant (including *R*epowering of an existing plant whenever the repowered plant utilizes combustion turbine, combined cycle, or integrated gasification combined cycle *technology*) with an installed capacity rating, combined for all units comprising such resource at a single point of interconnection to the Transmission System, of no less than 20 MW; provided, however, that a MOPR Screened Generation Resource shall not include: (i) the Installed Capacity equivalent (measured as of the time of clearing) of any of a resource's Unforced Capacity that has cleared any RPM Auction conducted prior to February 1, 2013 *or an uprate of such resource to the extent that the developer or owner of the uprate timely submitted a request for, and PJM issued, an offer floor pursuant to the unit-specific exception process of this subsection (h) before the start of the commencement of the Base Residual Auction for the 2016/2017 Delivery Year and the capacity associated with the uprate clears that auction*; (ii) any unit primarily fueled with landfill gas; (iii) any cogeneration unit that is certified or self-certified as a Qualifying Facility *(as defined in Part 292 of FERC's regulations)*, where the Capacity Market Seller is *the* owner of the Qualifying Facility *or has contracted for the Unforced Capacity of such facility* and the Unforced Capacity of the unit is no larger than approximately all of the Unforced Capacity Obligation of the host load, and all Unforced Capacity of the unit is used to meet the Unforced Capacity Obligation of the host load. A MOPR Screened Generation Resource shall include all Generation Capacity Resources located in the PJM Region that meet the foregoing criteria, and all Generation Capacity Resources located outside the PJM Region (where such Sell Offer is based solely on such resource) that entered commercial service on or after January 1, 2013, that meet the foregoing criteria and that require sufficient transmission

investment for delivery to the PJM Region to indicate a long-term commitment to providing capacity to the PJM Region.

(3) *MOPR Floor Offer Price.* The MOPR Floor Offer Price shall be 100% of the Net Asset Class Cost of New Entry for the relevant generator type and location, as determined hereunder. The gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be, for purposes of the Delivery Year commencing on June 1, 2015, the values indicated in the table below for each CONE Area for a combustion turbine generator ("CT"), a combined cycle generator ("CC"), and an integrated gasification combined cycle generator ("IGCC"), respectively, and shall be adjusted for subsequent Delivery Years in accordance with subsection (h)(3)(i) below. The estimated energy and ancillary service revenues for each type of plant shall be determined as described in subsection (h)(3)(ii) below.

	CONE Area 1	CONE Area 2	CONE Area 3	CONE Area 4	CONE Area 5
CT $/MW-yr	140,000	130,600	127,500	134,500	114,500
CC $/MW-yr	173,000	152,600	166,000	166,000	147,000
IGCC $/MW-yr	582,042	558,486	547,240	537,306	541,809

i) Commencing with the Delivery Year that begins on June 1, 2016, the gross Cost of New Entry component of the Net Asset Class Cost of New Entry shall be adjusted to reflect changes in generating plant construction costs in the same manner as set forth for the cost of new entry in section 5.10(a)(iv)(B), provided, however, that nothing herein shall preclude the Office of the Interconnection from filing to change the Net Asset Class Cost of New Entry for any Delivery Year pursuant to appropriate filings with FERC under the Federal Power Act.

ii) For purposes of this provision, the net energy and ancillary services revenue estimate for a combustion turbine generator shall be that determined by section 5.10(a)(v)(A) of this Attachment DD, provided that the energy revenue estimate for each CONE Area shall be based on the Zone within such CONE Area that has the highest energy revenue estimate calculated under the methodology in that subsection. The net energy and ancillary services revenue estimate for a combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator in the previous sentence, except that the heat rate assumed for the combined cycle resource shall be 6.722 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $3.23 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3198 per MW-year. The net energy and ancillary services revenue estimate for an integrated gasification combined cycle generator shall be determined in the same manner as that prescribed for a combustion turbine generator above, except that the heat rate assumed for the combined cycle resource shall be 8.7 MMbtu/Mwh, the variable operations and maintenance expenses for such resource shall be $7.77 per MWh, the Peak-Hour Dispatch scenario for both the Day-Ahead and Real-Time Energy Markets shall be modified to dispatch the resource continuously during the full peak-hour period, as described in section 2.46, for each such period that the resource is economic (using the test set forth in such

section), rather than only during the four-hour blocks within such period that such resource is economic, and the ancillary service revenues shall be $3,198 per MW-year.

(4) *Duration.* The MOPR Floor Offer Price shall apply to any Sell Offer based on a MOPR Screened Generation Resource (to the extent an exemption has not been obtained for such resource under this subsection) until *(and including)* the *first Delivery Year for* which *a* Sell Offer based on the non-exempt portion of such resource has cleared an RPM Auction.

(5) *Effect of Exemption or Exception.* To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, either a Competitive Entry Exemption or a Self-Supply Exemption, such offer (to the extent of such exemption) may include an offer price below the MOPR Floor Offer Price (including, without limitation, an offer price of zero or other indication of intent to clear regardless of price). *To the extent a Sell Offer in any RPM Auction for any Delivery Year is based on a MOPR Screened Generation Resource for which the Capacity Market Seller obtains, prior to the submission of such offer, a Unit-Specific Exception, such offer (to the extent of such exception) may include an offer price below the MOPR Floor Offer Price but no lower than the minimum offer price determined in such exception process*. The Installed Capacity equivalent of any MOPR Screened Generation Resource's Unforced Capacity that has both obtained such an exemption *or exception* and cleared the RPM Auction for which it obtained such exemption *or exception* shall not be subject to a MOPR Floor Offer Price in any subsequent RPM Auction, except as provided in subsection (h)(*10*) hereof.

(6) *Self-Supply Exemption.* A Capacity Market Seller that is a Self-Supply LSE may qualify its MOPR Screened Generation Resource in any RPM Auction for any Delivery Year for a Self-Supply Exemption if the MOPR Screened Generation Resource satisfies the criteria specified below:

i) Cost and revenue criteria. The costs and revenues associated with a MOPR Screened Generation Resource for which a Self-Supply LSE seeks a Self-Supply Exemption may permissibly reflect: (A) payments, concessions, rebates, subsidies, or incentives designed to incent or promote, or participation in a program, contract, or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (B) payments, concessions, rebates, subsidies or incentives from a county or other local government authority designed to incent, or participation in a program, contract or other arrangement established by a county or other local governmental authority utilizing eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; (C) revenues received by the Self-Supply LSE attributable to the inclusion of costs of the MOPR Screened Generation Resource in such LSE's regulated retail rates where such LSE is a *Vertically Integrated U*tility and the MOPR Screened Generation Resource is planned consistent with such LSE's most recent integrated resource plan found reasonable by the RERRA to meet the needs of its customers; and (D) payments to the Self-Supply LSE (such as retail rate recovery) traditionally associated with revenues and costs of Public Power Entities (or joint action of multiple Public Power Entities); revenues to a Public Power Entity from its contracts having a term of one year or more with its members or customers (including wholesale

power contracts between an electric cooperative and its members); or cost or revenue advantages related to a longstanding business model employed by the Self-Supply LSE, such as its financial condition, tax status, access to capital, or other similar conditions affecting the Self-Supply LSE's costs and revenues. A Self-Supply Exemption shall not be permitted to the extent that the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, has any formal or informal agreements or arrangements to seek, recover, accept or receive: (E) any material payments, concessions, rebates, or subsidies, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, not described by (A) through (D) of this section; or (F) other support through contracts having a term of one year or more obtained in any procurement process sponsored or mandated by any state legislature or agency connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. Any cost and revenue advantages described by (A) through (D) of this subsection that are material to the cost of the MOPR Screened Generation Resource and that are irregular or anomalous, that do not reflect arms-length transactions, or that are not in the ordinary course of the Self-Supply LSE's business, shall disqualify application of the Self-Supply Exemption unless the Self-Supply LSE demonstrates in the exemption process provided hereunder that such costs and revenues are consistent with the overall objectives of the Self-Supply Exemption.

ii) Owned and Contracted Capacity. To qualify for the Self-Supply Exemption, the Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, must demonstrate that the MOPR Screened Generation Resource is included in such LSE's Owned and Contracted Capacity and that its Owned and Contracted Capacity meets the criteria outlined below after the addition of such MOPR Screened Generation Resource.

iii) Maximum Net Short Position. If the excess, if any, of the Self-Supply LSE's Estimated Capacity Obligation above its Owned and Contracted Capacity ("Net Short") is less than the amount of Unforced Capacity specified in or calculated under the table below for all relevant areas based on the specified type of LSE, then this exemption criterion is satisfied. For this purpose, the Net Short position shall be calculated for any Self-Supply LSE requesting this exemption for the PJM Region and for each LDA specified in the table below in which the MOPR Screened Generation Resource is located (including through nesting of LDAs) to the extent the Self-Supply LSE has an Estimated Capacity Obligation in such LDA. If the Self-Supply LSE does not have an Estimated Capacity Obligation in an evaluated LDA, then the Self-Supply LSE is deemed to satisfy the test for that LDA.

Type of Self-Supply LSE	Maximum Net Short Position (UCAP MW, measured at RTO, MAAC, SWMAAC and EMAAC unless otherwise specified)
Single Customer Entity	150 MW
Public Power Entity	1000 MW
Multi-state Public Power Entity*	1000 MW in SWMAAC, EMAAC, or MAAC LDAs and 1800 MW RTO
Vertically Integrated Utility	20% of LSE's Reliability Requirement

*A Multi-state Public Power Entity shall not have more than 90% of its total load in any one state.

iv) Maximum Net Long Position. If the excess, if any, of the Self-Supply LSE's Owned and Contracted Capacity for the PJM Region above its Estimated Capacity Obligation for the PJM Region ("Net Long"), is less than the amount of Unforced Capacity specified in or calculated under the table below, then this exemption criterion is satisfied:

Self-Supply LSE Total Estimated Capacity Obligation in the PJM Region (UCAP MW)	Maximum Net Long Position (UCAP MW)
Less than 500	75 MW
Greater than or equal to 500 and less than 5,000	15% of LSE's Estimated Capacity Obligation
Greater than or equal to 5,000 and less than 15,000	750 MW
Greater than or equal to 15,000 and less than 25,000	1,000 MW
Greater than or equal to 25,000	4% of LSE's Estimated Capacity Obligation capped at 1300 MWs

If the MOPR Screened Generation Resource causes the Self-Supply LSE's Net Long Position to exceed the applicable threshold stated above, the MOPR Floor Offer Price shall apply, for the Delivery Year in which such threshold is exceeded, only to the quantity of Unforced Capacity of such resource that exceeds such threshold. In such event, such Unforced Capacity of such resource shall be subject to the MOPR Floor Offer Price for the period specified in subsection (h)(4) hereof; provided however, that any such Unforced Capacity that did not qualify for such exemption for such Delivery Year may qualify for such exemption in any RPM Auction for a future Delivery Year to the extent the Self-Supply LSE's future load growth accommodates the resource under the Net Long Position criteria.

v) Beginning with the Delivery Year that commences June 1, 2020, and continuing no later than for every fourth Delivery Year thereafter, the Office of the Interconnection shall review the Maximum Net Short and Net Long positions, as required by the foregoing subsection. Such review may include, without limitation, analyses under various appropriate scenarios of the minimum net short quantities at which the benefit to an LSE of a clearing price reduction for its capacity purchases from the RPM Auction outweighs the cost to the LSE of a new generating unit that is offered at an uneconomic price, and may, to the extent appropriate, reasonably balance the need to protect the market with the need to accommodate the normal business operations of Self-Supply LSEs. Based on the results of such review, PJM shall propose either to modify or retain the existing Maximum Net Short and Net Long positions. The Office of the Interconnection shall post publicly and solicit stakeholder comment regarding the proposal. If, as a result of this process, changes to the Maximum Net Short and/or Net Long positions are proposed, the Office of the Interconnection shall file such modified Maximum Net Short and/or Net Long positions with the FERC by October 1, prior to the conduct of the Base Residual Auction for the first Delivery Year in which the new values would be applied.

v*i*) Officer Certification. The Self-Supply LSE, acting either as the Capacity Market Seller or on behalf of the Capacity Market Seller, shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection in support of its exemption request is true and correct and the MOPR Screened Generation Resource will be Owned and Contracted Capacity for the purpose of self-supply for the benefit of the Self-Supply LSE; (B) the Self-Supply LSE has disclosed all material facts relevant to the exemption request; and (C) the Capacity Market Seller satisfies the criteria for the exemption.

vii) For purposes of the Self-Supply Exemption:

(A) "Self-Supply LSE" means the following types of Load Serving Entity, which operate under long-standing business models: Municipal/Cooperative Entity, Single Customer Entity, or Vertically Integrated Utility.

(B) "Municipal/Cooperative Entity" means cooperative and municipal utilities, including public power supply entities comprised of either or both of the same, and joint action agencies.

(C) "Vertically Integrated Utility" means a utility that owns generation, includes such generation in its regulated rates, and earns a regulated return on its investment in such generation.

(D) "Single Customer Entity" means an LSE that serves at retail only customers that are under common control with such LSE, where such control means holding 51% or more of the voting securities or voting interests of the LSE and all its retail customers.

(E) All capacity calculations shall be on an Unforced Capacity basis.

(F) Estimated Capacity Obligations and Owned and Contracted Capacity shall be measured on a three-year average basis for the three years starting with the first day of the Delivery Year associated with the RPM Auction for which the exemption is being sought ("MOPR Exemption Measurement Period"). Such measurements shall be verified by PJM using the latest available data that PJM uses to determine capacity obligations.

(G) The Self-Supply LSE's Estimated Capacity Obligation shall be the average, for the three Delivery Years of the MOPR Exemption Measurement Period, of the Self-Supply LSE's estimated share of the most recent available Zonal Peak Load Forecast for each such Delivery Year for each Zone in which the Self-Supply LSE will serve load during such Delivery Year, times the Forecast Pool Requirement established for the first such Delivery Year, shall be stated on an Unforced Capacity basis. The Self-

Supply LSE's share of such load shall be determined by the ratio of: (1) the peak load contributions, from the most recent summer peak for which data is available at the time of the exemption request, of the customers or areas within each Zone for which such LSE will have load-serving responsibility during the first Delivery Year of the MOPR Exemption Measurement Period to (2) the weather-normalized summer peak load of such Zone for the same summer peak period addressed in the previous clause. *Notwithstanding the foregoing, solely in the case of any Self-Supply LSE that demonstrates to the Office of the Interconnection that its annual peak load occurs in the winter, such LSE's Estimated Capacity Obligation determined solely for the purposes of this subsection 5.14(h) shall be based on its winter peak.* Once submitted, an exemption request shall not be subject to change due to later revisions to the PJM load forecasts for such Delivery Years. The Self-Supply LSE's Estimated Capacity Obligation shall be limited to the LSE's firm obligations to serve specific identifiable customers or groups of customers including native load obligations and specific load obligations in effective contracts for which the term of the contract includes at least a portion of the Delivery Year associated with the RPM Auction for which the exemption is requested (and shall not include load that is speculative or load obligations that are not native load or customer specific); as well as retail loads of entities that directly (as through charges on a retail electric bill) or indirectly, contribute to the cost recovery of the MOPR Screened Generation Resource; provided, however, nothing herein shall require a Self-Supply LSE that is a joint owner of a MOPR Screened Generation Resource to aggregate its expected loads with the loads of any other joint owner for purposes of such Self-Supply LSE's exemption request.

(H) "Owned and Contracted Capacity" includes all of the Self-Supply LSE's qualified Capacity Resources, whether internal or external to PJM. For purposes of the Self-Supply Exemption, Owned and Contracted Capacity includes Generation Capacity Resources without regard to whether such resource has failed or could fail the Competitive and Non-Discriminatory procurement standard of the Competitive Entry Exemption. To qualify for a Self-Supply Entry exemption, the MOPR Screened Generation must be used by the Self-Supply LSE, meaning such Self-Supply LSE is the beneficial off-taker of such generation such that the owned or contracted for MOPR Screened Generation is for the Self-Supply LSE's use to supply its customer(s).

(I) If multiple entities will have an ownership or contractual share in, or are otherwise sponsoring, the MOPR Screened Generation Resource, the positions of each such entity will be measured and considered for a Self-Supply Exemption with respect to the individual Self-Supply LSE's ownership or contractual share of such resource.

(7) <u>*Competitive Entry Exemption*</u>. A Capacity Market Seller may qualify a MOPR Screened Generation Resource for a Competitive Entry Exemption in any RPM Auction for any Delivery Year if the Capacity Market Seller demonstrates that the MOPR Screened Generation Resource satisfies all of the following criteria:

i) No costs *of the MOPR Screened Generation Resource* are recovered from customers either directly or indirectly through a non-bypassable charge, *except in*

the event that Sections 5.14(h)(7)(ii) and (iii), to the extent either or both are applicable to such resource, are satisfied.

ii) No costs of the MOPR Screened Generation Resource are supported through any contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes that are not Competitive and Non-Discriminatory. The Office of the Interconnection and the Market Monitoring Unit may deem a procurement process to be "Competitive and Non-Discriminatory" only if: (A) both new and existing resources may satisfy the requirements of the procurement; (B) the requirements of the procurement are fully objective and transparent; (C) the procurement terms do not restrict the type of capacity resources that may participate in and satisfy the requirements of the procurement; (D) the procurement terms do not include selection criteria that could give preference to new resources; and (E) the procurement terms do not use indirect means to discriminate against existing capacity, such as geographic constraints inconsistent with LDA import capabilities, unit technology or unit fuel requirements or unit heat-rate requirements, identity or nature of seller requirements, or requirements for new construction.

iii) The Capacity Market Seller does not have any formal or informal agreements or arrangements to seek, recover, accept or receive any (A) material payments, concessions, rebates, or subsidies directly or indirectly from any governmental entity connected with the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource, or (B) other material support through contracts having a term of one year or more obtained in any state-sponsored or state-mandated procurement processes, connected to the construction, or clearing in any RPM Auction, of the MOPR Screened Generation Resource. These restrictions shall not include (C) payments (including payments in lieu of taxes), concessions, rebates, subsidies, or incentives designed to incent, or participation in a program, contract or other arrangement that utilizes criteria designed to incent or promote, general industrial development in an area; (D) payments, concessions, rebates, subsidies or incentives designed to incent, or participation in a program, contract or other arrangements from a county or other local governmental authority using eligibility or selection criteria designed to incent, siting facilities in that county or locality rather than another county or locality; or (E) federal government production tax credits, investment tax credits, and similar tax advantages or incentives that are available to generators without regard to the geographic location of the generation.

iv) The Capacity Market Seller shall submit a sworn, notarized certification of a duly authorized officer, certifying that the officer has personal knowledge of, or has engaged in a diligent inquiry to determine, the facts and circumstances supporting the Capacity Market Seller's decision to submit a Sell Offer into the RPM Auction for the MOPR Screened Generation Resource and seek an exemption from the MOPR Floor Offer Price for such resource, and, to the best of his/her knowledge and belief: (A) the information supplied to the Market Monitoring Unit and the Office of Interconnection to support its exemption is true and correct and the resource is being constructed or contracted for purposes of competitive entry by the Capacity Market Seller; (B) the Capacity Market Seller has disclosed all material facts relevant to the request for the exemption; and (C) the exemption request satisfies the criteria for the exemption.

(8) Unit-Specific Exception. A Capacity Market Seller intending to submit a Sell Offer in any RPM Auction below the MOPR Floor Offer Price for any Delivery Year based on a MOPR Screened Generation Resource may, at its election, submit a request for a Unit-Specific Exception in addition to, or in lieu of, a request for a Self-Supply Exemption or a Competitive Entry Exemption, for such MOPR Screened Generation Resource. A Sell Offer meeting the Unit-Specific Exception criteria in this subsection shall be permitted and shall not be re-set to the MOPR Floor Offer Price if the Capacity Market Seller obtains a determination from the Office of the Interconnection or the Commission, prior to the RPM Auction in which it seeks to submit the Sell Offer, that such Sell Offer is permissible because it is consistent with the competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets. The following requirements shall apply to requests for such determinations:

i) The Capacity Market Seller shall submit a written request with all of the required documentation as described below and in the PJM Manuals. For such purpose, per subsection (h)(9)(i) below, the Office of the Interconnection shall post a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price expected to be established hereunder. If the MOPR Floor Offer Price subsequently established for the relevant Delivery Year is less than the Sell Offer, the Sell Offer shall be permitted and no exception shall be required.

ii) As more fully set forth in the PJM Manuals, the Capacity Market Seller must include in its request for an exception under this subsection documentation to support the fixed development, construction, operation, and maintenance costs of the MOPR Screened Generation Resource, as well as estimates of offsetting net revenues. Estimates of costs or revenues shall be supported at a level of detail comparable to the cost and revenue estimates used to support the Net Asset Class Cost of New Entry established under this section 5.14(h). As more fully set forth in the PJM Manuals, supporting documentation for project costs may include, as applicable and available, a complete project description; environmental permits; vendor quotes for plant or equipment; evidence of actual costs of recent comparable projects; bases for electric and gas interconnection costs and any cost contingencies; bases and support for property taxes, insurance, operations and maintenance ("O&M") contractor costs, and other fixed O&M and administrative or general costs; financing documents for construction–period and permanent financing or evidence of recent debt costs of the seller for comparable investments; and the bases and support for the claimed capitalization ratio, rate of return, cost-recovery period, inflation rate, or other parameters used in financial modeling. Such documentation also shall identify and support any sunk costs that the Capacity Market Seller has reflected as a reduction to its Sell Offer The request shall include a certification, signed by an officer of the Capacity Market Seller, that the claimed costs accurately reflect, in all material respects, the seller's reasonably expected costs of new entry and that the request satisfies all standards for a Unit-Specific Exception hereunder. The request also shall identify all revenue sources relied upon in the Sell Offer to offset the claimed fixed costs, including, without limitation, long-term power supply contracts, tolling agreements, or tariffs on file with state regulatory agencies, and shall demonstrate that such offsetting revenues are consistent, over a reasonable time period identified by the Capacity Market Seller, with the standard prescribed above. In making such demonstration, the Capacity Market Seller may rely upon forecasts of competitive electricity prices in the PJM Region based on well defined models that

include fully documented estimates of future fuel prices, variable operation and maintenance expenses, energy demand, emissions allowance prices, and expected environmental or energy policies that affect the seller's forecast of electricity prices in such region, employing input data from sources readily available to the public. Documentation for net revenues also may include, as available and applicable, plant performance and capability information, including heat rate, start-up times and costs, forced outage rates, planned outage schedules, maintenance cycle, fuel costs and other variable operations and maintenance expenses, and ancillary service capabilities.

iii) A Sell Offer evaluated under the Unit-Specific Exception shall be permitted if the information provided reasonably demonstrates that the Sell Offer's competitive, cost-based, fixed, net cost of new entry is below the MOPR Floor Offer Price, based on competitive cost advantages relative to the costs implied by the MOPR Floor Offer Price, including, without limitation, competitive cost advantages resulting from the Capacity Market Seller's business model, financial condition, tax status, access to capital or other similar conditions affecting the applicant's costs, or based on net revenues that are reasonably demonstrated hereunder to be higher than those implied by the MOPR Floor Offer Price. Capacity Market Sellers shall be asked to demonstrate that claimed cost advantages or sources of net revenue that are irregular or anomalous, that do not reflect arm's-length transactions, or that are not in the ordinary course of the Capacity Market Seller's business are consistent with the standards of this subsection. Failure to adequately support such costs or revenues so as to enable the Office of the Interconnection to make the determination required in this section will result in denial of a Unit-Specific Exception hereunder by the Office of the Interconnection.

(*9*) *Exemption/Exception Process.*

i) *The Office of the Interconnection shall post, by no later than one hundred fifty (150) days prior to the commencement of the offer period for an RPM Auction, a preliminary estimate for the relevant Delivery Year of the MOPR Floor Offer Price.*

ii) The Capacity Market Seller must submit its request for a *Unit-Specific Exception,* Competitive Entry Exemption or a Self-Supply Exemption in writing simultaneously to the Market Monitoring Unit and the Office of Interconnection by no later than one hundred thirty five (135) days prior to the commencement of the offer period for the RPM Auction in which such seller seeks to submit its Sell Offer. The Capacity Market Seller shall include in its request a description of its MOPR Screened Generation Resource, the exemption *or exception* that the Capacity Market Seller is requesting, and all documentation necessary to demonstrate that the exemption *or exception* criteria are satisfied, including without limitation the applicable certification(s) specified in this subsection (h). In addition to the documentation identified herein and in the PJM Manuals, the Capacity Market Seller shall provide any additional supporting information reasonably requested by the Office of the Interconnection or the Market Monitoring Unit to evaluate the Sell Offer. Requests for additional documentation will not extend the deadline by which the Office of the Interconnection or the Market Monitoring Unit must provide their determinations of the exemption request. The Capacity Market Seller shall have an ongoing obligation through the closing of the offer period for the RPM Auction to update the request to reflect any material changes in the request.

*i*ii) As further described in Section II.D. of Attachment M-Appendix to this Tariff, the Market Monitoring Unit shall review the request and supporting documentation and shall provide its determination by no later than forty-five (45) days after receipt of the exemption *or exception* request. The Office of the Interconnection shall also review all exemption a*nd exception* requests to determine whether the request is acceptable in accordance with the standards and criteria under this section 5.14(h) and shall provide its determination in writing to the Capacity Market Seller, with a copy to the Market Monitoring Unit, by no later than sixty-five (65) days after receipt of the exemption *or exception* request. The Office of the Interconnection shall reject a requested exemption *or exception* if the Capacity Market Seller*'s request does not comply with the PJM Market Rules, as interpreted and applied by the Office of the Interconnection. Such rejection shall specify those points of non-compliance upon which the Office of the Interconnection based its rejection of the exemption or exception request.* If the Office of the Interconnection does not provide its determination *on an exemption or exception request* by no later than sixty-five (65) days after receipt of the exemption *or exception* request, the request shall be deemed granted. *Following the Office of the Interconnection's determination on a Unit-Specific Exception request, the Capacity Market Seller shall notify the Market Monitoring Unit and the Office of the Interconnection, in writing, of the minimum level of Sell Offer, consistent with such determination, to which it agrees to commit by no later than five (5) days after receipt of the Office of the Interconnection's determination of its Unit-Specific Exception request.* A Capacity Market Seller that is dissatisfied with any determination hereunder may seek any remedies available to it from FERC; provided, however, that the Office of the Interconnection will proceed with administration of the Tariff and market rules unless and until ordered to do otherwise by FERC.

(*10*) *Procedures and Remedies in Cases of Suspected Fraud or Material Misrepresentation or Omissions in Connection with Exemption Requests.*

In the event the Office of the Interconnection reasonably believes that a request for a Competitive Entry Exemption or a Self-Supply Exemption that has been granted contains fraudulent or material misrepresentations or fraudulent or material omissions such that the Capacity Market Seller would not have been eligible for the exemption for that resource had the request not contained such misrepresentations or omissions, then:

i) if the Office of the Interconnection provides written notice of revocation to the Capacity Market Seller no later than thirty (30) days prior to the commencement of the offer period for the RPM Auction for which the seller submitted a fraudulent exemption request, the Office of the Interconnection shall revoke the exemption for that auction. In such event, the Office of the Interconnection shall make any filings with FERC that the Office of the Interconnection deems necessary, and

ii) if the Office of the Interconnection does not provide written notice of revocation no later than 30 days before the start of the relevant RPM Auction, then the Office of the Interconnection may not revoke the exemption absent FERC approval. In any such filing to FERC, the requested remedies shall include (A) in the event that such resource has not cleared in the RPM Auction for which the exemption has been granted and the filing is made no later than 5 days prior to the commencement of the offer period for the RPM Auction, revocation of the exemption or, (B) in the event that the resource has cleared the RPM Auction for which the

exemption has been granted and the filing is made no later than two (2) years after the close of the offer period for the relevant RPM Auction, suspension of any payments, during the pendency of the FERC proceeding, to the Capacity Market Seller for the resource that cleared in any RPM Auction relying on such exemption; and suspension of the Capacity Market Seller's exemption for that resource for future RPM Auctions.

iii) Prior to any automatic revocation or submission to FERC, the Office of the Interconnection and/or the Market Monitoring Unit shall notify the affected Capacity Market Seller and, to the extent practicable, provide the Capacity Market Seller an opportunity to explain the alleged misrepresentation or omission. Any filing to FERC under this provision shall seek fast track treatment and neither the name nor any identifying characteristics of the Capacity Market Seller or the resource shall be publicly revealed, but otherwise the filing shall be public. The Capacity Market Seller may apply for a new exemption for that resource for subsequent auctions, including auctions held during the pendency of the FERC proceeding. In the event that the Capacity Market Seller is cleared by FERC from such allegations of misrepresentations or omissions then the exemption shall be restored to the extent and in the manner permitted by FERC. The remedies required by this subsection (h)(*10*) to be requested in any filing to FERC shall not be exclusive of any other remedies or penalties that may be pursued against the Capacity Market Seller.

i) Capacity Export Charges and Credits

(1) Charge

Each Capacity Export Transmission Customer shall incur for each day of each Delivery Year a Capacity Export Charge equal to the Reserved Capacity of Long-Term Firm Transmission Service used for such export ("Export Reserved Capacity") multiplied by (the Final Zonal Capacity Price for such Delivery Year for the Zone encompassing the interface with the Control Area to which such capacity is exported minus the Final Zonal Capacity Price for such Delivery Year for the Zone in which the resources designated for export are located, but not less than zero). If more than one Zone forms the interface with such Control Area, then the amount of Reserved Capacity described above shall be apportioned among such Zones for purposes of the above calculation in proportion to the flows from such resource through each such Zone directly to such interface under CETO/CETL analysis conditions, as determined by the Office of the Interconnection using procedures set forth in the PJM Manuals. The amount of the Reserved Capacity that is associated with a fully controllable facility that crosses such interface shall be completely apportioned to the Zone within which such facility terminates.

(2) Credit

To recognize the value of firm Transmission Service held by any such Capacity Export Transmission Customer, such customer assessed a charge under section 5.14(i)(1) also shall receive a credit, comparable to the Capacity Transfer Rights provided to Load-Serving Entities under section 5.15. Such credit shall be equal to the locational capacity price difference specified in section 5.14(i)(1) times the Export Customer's Allocated Share determined as follows:

Export Customer's Allocated Share equals

(Export Path Import * Export Reserved Capacity) /

(Export Reserved Capacity + Daily Unforced Capacity Obligations of all LSEs in such Zone).

Where:

"Export Path Import" means the megawatts of Unforced Capacity imported into the export interface Zone from the Zone in which the resource designated for export is located.

If more than one Zone forms the interface with such Control Area, then the amount of Export Reserved Capacity shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

(3) Distribution of Revenues

Any revenues collected from the Capacity Export Charge with respect to any capacity export for a Delivery Year, less the credit provided in subsection (i)(2) for such Delivery Year, shall be distributed to the Load Serving Entities in the export-interface Zone that were assessed a

Locational Reliability Charge for such Delivery Year, pro rata based on the Daily Unforced Capacity Obligations of such Load-serving Entities in such Zone during such Delivery Year. If more than one Zone forms the interface with such Control Area, then the revenues shall be apportioned among such Zones for purposes of the above calculation in the same manner as set forth in subsection (i)(1) above.

5.14A Demand Response Transition Provision for RPM Delivery Years 2012/2013, 2013/2014, and 2014/2015

A. This Transition Provision applies only with respect to Demand Resources cleared in the Base Residual Auction for any or all of the 2012/2013, 2013/2014, or 2014/2015 Delivery Years (hereafter, "Transition Delivery Years" and each a "Transition Delivery Year") by a Curtailment Service Provider as an aggregator of end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option. A Curtailment Service Provider meeting the description of the preceding sentence is hereafter in this Section 5.14A referred to as a "Qualified DR Provider."

B. In the event that a Qualified DR Provider concludes that its cleared Demand Resource for a Transition Delivery Year is not viable under the revised Reporting and Compliance provisions of the Emergency Load Response Program which became effective on November 7, 2011, pursuant to the Commission's order issued on November 4, 2011, in Docket No. ER11-3322-000 (137 FERC ¶ 61,108), the Qualified DR Provider must so inform PJM in writing by no later than 30 days prior to the next Incremental Auction for the Transition Delivery Year for which the identified Demand Resource was cleared. A Qualified DR Provider that does not timely provide the notice described in this paragraph shall be excluded from application of the remainder of this Transition Provision. A Demand Resource cleared for a Transition Delivery Year is not viable

for purposes of this Transition Provision to the extent that it relies upon load reduction by any end-use customer for which the applicable Qualified DR Provider anticipated, when it offered the Demand Resource, measuring load reduction at loads in excess of such customer's peak load contribution during Emergency Load Response dispatch events or tests.

1. In the event a Qualified DR Provider that participates in an Incremental Auction after providing notice pursuant to paragraph B. above purchases Capacity Resources to replace its previously cleared Demand Resource at a price that exceeds the price at which the provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year, the Qualified DR Provider shall receive a DR Capacity Transition Credit in an amount determined by the following:

   DRTC = (IAP – BRP) * DRMW

   Where:

   DRTC is the amount of the DR Capacity Transition Credit for the Qualified DR Provider, expressed in dollars;

   IAP = the Capacity Resource Clearing Price paid by the Qualified DR Provider for replacement Capacity Resources in the Incremental Auction for the relevant Transition Delivery Year;

   BRP = the Capacity Resource Clearing Price at which the Qualified DR Provider's Demand Resource cleared in the Base Residual Auction for the same Transition Delivery Year; and

   DRMW = the capacity in MW of the Qualified DR Provider's previously cleared Demand Resource.

2. All DR Capacity Transition Credits will be paid weekly to the recipient Qualified DR Providers by PJMSettlement during the relevant Transition Delivery Year.

3. The cost of payments of DR Capacity Transition Credits to Qualified DR Providers shall be included in the Locational Reliability Charge collected by PJMSettlement during the relevant Transition Delivery Year from Load-Serving Entities in the LDA(s) for which the Qualified DR Provider's subject Demand Resource was cleared.

C. A Qualified DR Provider may seek compensation related to its previously cleared Demand Resource for a particular Transition Delivery Year, in lieu of any DR Capacity Transition Credits for which it otherwise might be eligible under paragraph B.1. above, under the following conditions:

1. The Qualified DR Provider must provide timely notice to PJM in accordance with paragraph B of this Transition Provision, and

2. The Qualified DR Provider must demonstrate to PJM's reasonable satisfaction, not later than 60 days prior to the start of the applicable Transition Delivery Year, that

a. the Qualified DR Provider entered into contractual arrangements on or before April 7, 2011, with one or more end-use customers registered for the Emergency Load Response Program as Full Program Option or Capacity Only Option in association with the Demand Resource identified in the provider's notice pursuant to paragraph B above,

b. under which the Qualified DR Provider is unavoidably obligated to pay to such end-use customers during the relevant Transition Delivery Year

c. an aggregate amount that exceeds:

(i) any difference of (A) the amount the Qualified DR Provider is entitled to receive in payment for the previously cleared Demand Resource it designated as not viable in its notice pursuant to paragraph B of this provision, minus (B) the amount the provider is obligated to pay for capacity resources it purchased in the Incremental Auctions to replace the Demand Resource the provider designated as not viable, plus

(ii) any monetary gains the Qualified DR Provider realizes from purchases of Capacity Resources in Incremental Auctions for the same Transition Delivery Year to replace any Demand Resources that the Qualified DR Provider cleared in the applicable Base Residual Auction other than the resource designated as not viable in the provider's notice pursuant to paragraph (B) of this provision,

(iii) where "monetary gains" for the purpose of clause (ii) shall be any positive difference of (A) the aggregate amount the Qualified DR Provider is entitled to receive in payment for any such other Demand Resource it cleared in the Base Residual Auction, minus (B) the aggregate amount the provider is obligated to pay for capacity resources it purchased in the applicable Incremental Auctions to replace any such other Demand Resource the provider cleared in the Base Residual Auction.

D. A Qualified DR Provider which demonstrates satisfaction of the conditions of paragraph C of this Transition Provision shall be entitled to an Alternative DR Transition Credit equal to the amount described in paragraph C.2.c. above. Any Alternative DR Transition Credit provided in accordance with this paragraph shall be paid and collected by PJMSettlement in the same manner as described in paragraphs B.2. and B.3. of this Transition Provision, provided, however, that each Qualified DR Provider receiving an Alternative DR Transition Credit shall submit to PJM within 15 days following the end of each month of the relevant Transition Delivery Year a report providing the calculation described in paragraph C.2.c. above, using actual amounts paid and received through the end of the month just ended. The DR Provider's Alternative DR Transition Credit shall be adjusted as necessary (including, if required, in the month following the final month of the Transition Delivery Year) to ensure that the total credit paid to the

Qualified DR Provider for the Transition Delivery Year will equal, but shall not exceed, the amount described in paragraph C.2.c. above, calculated using the actual amounts paid and received by the Qualified DR Provider.

Section(s) of the
PJM Reliability Assurance Agreement

(Clean Format)

D. FRR Capacity Plans

1. Each FRR Entity shall submit its initial FRR Capacity Plan as required by subsection C.1 of this Schedule, and shall annually extend and update such plan by no later than one month prior to the Base Residual Auction for each succeeding Delivery Year in such plan. Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each Planned Generation Capacity Resource or Planned Demand Resource, the planned deactivation or retirement of any Generation Capacity Resource or Demand Resource, and the status of commitments for each sale or purchase of capacity included in such plan.

2. The FRR Capacity Plan of each FRR Entity that commits that it will not sell surplus Capacity Resources as a Capacity Market Seller in any auction conducted under Attachment DD of the PJM Tariff, or to any direct or indirect purchaser that uses such resource as the basis of any Sell Offer in such auction, shall designate Capacity Resources in a megawatt quantity no less than the Forecast Pool Requirement for each applicable Delivery Year times the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast for such Delivery Year, as determined in accordance with procedures set forth in the PJM Manuals. For the 2016/2017 Delivery Year and prior Delivery Years, the set of Capacity Resources designated in the FRR Capacity Plan must meet the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation. For the 2017/2018 Delivery Year and subsequent Delivery Years, the set of Capacity Resources designated in the FRR Capacity Plan must satisfy the Limited Resource Constraints and the Sub-Annual Resource Constraints applicable to the FRR Entity's capacity obligation. If the FRR Entity is not responsible for all load within a Zone, the Preliminary Forecast Peak Load for such entity shall be the FRR Entity's Obligation Peak Load last determined prior to the Base Residual Auction for such Delivery Year, times the Base Zonal FRR Scaling Factor. The FRR Capacity Plan of each FRR Entity that does not commit that it will not sell surplus Capacity Resources as set forth above shall designate Capacity Resources at least equal to the Threshold Quantity. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast exceeds the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan shall be updated to designate additional Capacity Resources in an amount no less than the Forecast Pool Requirement times such increase; provided, however, any excess megawatts of Capacity Resources included in such FRR Entity's previously designated Threshold Quantity, if any, may be used to satisfy the capacity obligation for such increased load. To the extent the FRR Entity's allocated share of the Final Zonal Peak Load Forecast is less than the FRR Entity's allocated share of the Preliminary Zonal Peak Load Forecast, such FRR Entity's FRR Capacity Plan may be updated to release previously designated Capacity Resources in an amount no greater than the Forecast Pool Requirement times such decrease. Peak load values referenced in this section shall be adjusted as necessary to take into account any applicable Nominal PRD Values approved pursuant to Schedule 6.1 of this Agreement. Any FRR Entity seeking an adjustment to peak load for Price Responsive Demand must submit a separate PRD Plan in compliance with Section 6.1 (provided that the FRR Entity shall not specify any PRD Reservation Price), and shall register all PRD-eligible load needed to satisfy its PRD commitment and be subject to compliance charges as set forth in that Schedule under the circumstances specified therein; provided that for non-compliance by an FRR Entity, the compliance charge rate shall be equal to 1.20 times the Capacity Resource Clearing Price

resulting from all RPM Auctions for such Delivery Year for the LDA encompassing the FRR Entity's Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in the RPM auctions for such Delivery Year; and provided further that an alternative PRD Provider may provide PRD in an FRR Service Area by agreement with the FRR Entity responsible for the load in such FRR Service Area, subject to the same terms and conditions as if the FRR Entity had provided the PRD.

3. As to any FRR Entity, the Base Zonal FRR Scaling Factor for each Zone in which it serves load for a Delivery Year shall equal ZPLDY/ZWNSP, where:

ZPLDY = Preliminary Zonal Peak Load Forecast for such Zone for such Delivery Year; and

ZWNSP = Zonal Weather-Normalized Summer Peak Load for such Zone for the summer concluding four years prior to the commencement of such Delivery Year.

4. Capacity Resources identified and committed in an FRR Capacity Plan shall meet all requirements under this Agreement and the PJM Operating Agreement applicable to Capacity Resources, including, as applicable, requirements and milestones for Planned Generation Capacity Resources and Planned Demand Resources. A Capacity Resource submitted in an FRR Capacity Plan must be on a unit-specific basis, and may not include "slice of system" or similar agreements that are not unit specific. An FRR Capacity Plan may include bilateral transactions that commit capacity for less than a full Delivery Year only if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. All demand response, load management, energy efficiency, or similar programs on which such FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan submitted three years in advance of such Delivery Year and must satisfy all requirements applicable to Demand Resources or Energy Efficiency Resources, as applicable, including, without limitation, those set forth in Schedule 6 to this Agreement and the PJM Manuals; provided, however, that previously uncommitted Unforced Capacity from such programs may be used to satisfy any increased capacity obligation for such FRR Entity resulting from a Final Zonal Peak Load Forecast applicable to such FRR Entity.

5. For each LDA for which the Office of the Interconnection has established a separate Variable Resource Requirement Curve for any Delivery Year addressed by such FRR Capacity Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA. Such minimum percentage ("Percentage Internal Resources Required") will be calculated as the LDA Reliability Requirement less the CETL for the Delivery Year, as determined by the RTEP process as set forth in the PJM Manuals. Such requirement shall be expressed as a percentage of the Unforced Capacity Obligation based on the Preliminary Zonal Peak Load Forecast multiplied by the Forecast Pool Requirement.

6. An FRR Entity may reduce such minimum percentage as to any LDA to the extent the FRR Entity commits to a transmission upgrade that increases the capacity emergency transfer limit for such LDA. Any such transmission upgrade shall adhere to all requirements for a Qualified Transmission Upgrade as set forth in Attachment DD to the PJM Tariff. The increase in CETL used in the FRR Capacity Plan shall be that approved by PJM prior to inclusion of any

such upgrade in an FRR Capacity Plan. The FRR Entity shall designate specific additional Capacity Resources located in the LDA from which the CETL was increased, to the extent of such increase.

7. The Office of the Interconnection will review the adequacy of all submittals hereunder both as to timing and content. A Party that seeks to elect the FRR Alternative that submits an FRR Capacity Plan which, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, shall not be permitted to elect the FRR Alternative. If a previously approved FRR Entity submits an FRR Capacity Plan that, upon review by the Office of the Interconnection, is determined not to satisfy such Party's capacity obligations hereunder, the Office of the Interconnection shall notify the FRR Entity, in writing, of the insufficiency within five (5) business days of the submittal of the FRR Capacity Plan. If the FRR Entity does not cure such insufficiency within five (5) business days after receiving such notice of insufficiency, then such FRR Entity shall be assessed an FRR Commitment Insufficiency Charge, in an amount equal to two times the Cost of New Entry for the relevant location, in $/MW-day, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation (including any Threshold Quantity requirement) in such FRR Capacity Plan, for the remaining term of such plan.

8. In a state regulatory jurisdiction that has implemented retail choice, the FRR Entity must include in its FRR Capacity Plan all load, including expected load growth, in the FRR Service Area, notwithstanding the loss of any such load to or among alternative retail LSEs. In the case of load reflected in the FRR Capacity Plan that switches to an alternative retail LSE, where the state regulatory jurisdiction requires switching customers or the LSE to compensate the FRR Entity for its FRR capacity obligations, such state compensation mechanism will prevail. In the absence of a state compensation mechanism, the applicable alternative retail LSE shall compensate the FRR Entity at the capacity price in the unconstrained portions of the PJM Region, as determined in accordance with Attachment DD to the PJM Tariff, provided that the FRR Entity may, at any time, make a filing with FERC under Sections 205 of the Federal Power Act proposing to change the basis for compensation to a method based on the FRR Entity's cost or such other basis shown to be just and reasonable, and a retail LSE may at any time exercise its rights under Section 206 of the FPA.

9. Notwithstanding the foregoing, in lieu of providing the compensation described above, such alternative retail LSE may, for any Delivery Year subsequent to those addressed in the FRR Entity's then-current FRR Capacity Plan, provide to the FRR Entity Capacity Resources sufficient to meet the capacity obligation described in paragraph D.2 for the switched load. Such Capacity Resources shall meet all requirements applicable to Capacity Resources pursuant to this Agreement and the PJM Operating Agreement, all requirements applicable to resources committed to an FRR Capacity Plan under this Agreement, and shall be committed to service to the switched load under the FRR Capacity Plan of such FRR Entity. The alternative retail LSE shall provide the FRR Entity all information needed to fulfill these requirements and permit the resource to be included in the FRR Capacity Plan. The alternative retail LSE, rather than the FRR Entity, shall be responsible for any performance charges or compliance penalties related to the performance of the resources committed by such LSE to the switched load. For any Delivery Year, or portion thereof, the foregoing obligations apply to the alternative retail LSE serving the

load during such time period. PJM shall manage the transfer accounting associated with such compensation and shall administer the collection and payment of amounts pursuant to the compensation mechanism.

Such load shall remain under the FRR Capacity Plan until the effective date of any termination of the FRR Alternative and, for such period, shall not be subject to Locational Reliability Charges under Section 7.2 of this Agreement.

F. FRR Daily Unforced Capacity Obligations and Deficiency Charges

1. For each billing month during a Delivery Year, the Daily Unforced Capacity Obligation of an FRR Entity shall be determined on a daily basis for each Zone as follows:

Daily Unforced Capacity Obligation = [(OPL * Final Zonal FRR Scaling Factor) – Nominal PRD Value committed by the FRR Entity] * FPR

where:

OPL =Obligation Peak Load, defined as the daily summation of the weather-adjusted coincident summer peak, last preceding the Delivery Year, of the end-users in such Zone (net of operating Behind The Meter Generation, but not to be less than zero) for which such Party was responsible on that billing day, as determined in accordance with the procedures set forth in the PJM Manuals

Final Zonal FRR Scaling Factor = FZPLDY/FZWNSP;

FZPLDY = Final Zonal Peak Load Forecast for such Delivery Year; and

FZWNSP = Zonal Weather-Normalized Peak Load for the summer concluding prior to the commencement of such Delivery Year.

2. An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in such entity's FRR Capacity Plan for each day during a Delivery Year that it fails to satisfy its Daily Unforced Capacity Obligation in each Zone. Such FRR Capacity Deficiency Charge shall be in an amount equal to the deficiency below such FRR Entity's Daily Unforced Capacity Obligation for such Zone times (1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions).

3. If an FRR Entity acquires load that is not included in the Preliminary Zonal Peak Load Forecast such acquired load shall be treated in the same manner as provided in Sections H.1 and H.2 of this Schedule.

4. The shortages in meeting the minimum requirement within the constrained zones and the shortage in meeting the total obligation are first calculated. The shortage in the unconstrained area is calculated as the total shortage less shortages in constrained zones and excesses in constrained zones (the shortage is zero if this is a negative number). The Capacity Deficiency Charge is charged to the shortage in each zone and in the unconstrained area separately. This procedure is used to allow the use of capacity excesses from constrained zones to reduce shortage in the unconstrained area and to disallow the use of capacity excess from unconstrained area to reduce shortage in constrained zones.

5. For Delivery Years during the period starting June 1, 2014 and ending May 31, 2017, the shortages in meeting the Minimum Annual Resource Requirement and the Minimum Extended Summer Resource Requirement associated with the FRR Entity's capacity obligation are calculated separately. For such period, the applicable penalty rate is calculated for Annual Resources, Extended Summer Demand Resources, and Limited Resources as (1.20 times the Capacity Resource Clearing Price resulting from all RPM Auctions for such Delivery Year for the LDA encompassing such Zone, weight-averaged for the Delivery Year based on the prices established and quantities cleared in such auctions). For Delivery Years beginning June 1, 2017, the FRR Entity shall receive no credit for Limited Demand Resources to the extent committed in excess of the applicable Limited Resource Constraint and shall receive no credit for the sum of Limited Demand Resources and Extended Summer Demand Resources to the extent the sum of the Unforced Capacity of such resources exceeds the applicable Sub-Annual Resource Constraint.