Large Filing Separator Sheet

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7. GENERATION RESOURCE RATING TEST FAILURE CHARGE

7.1 Generation Resource Rating Test Failure Charges

A Generation Resource Rating Test Failure Charge shall be assessed on any Market Seller that commits a Generation Capacity Resource for a Delivery Year, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, if such resource fails a generation resource capacity test, as provided herein.

a) Generation Resource Fails Capacity Test in Delivery Year

Each Generation Capacity Resource committed for a Delivery Year shall be obligated to complete a generation resource capacity test, as described in the PJM Manuals. The Market Seller that committed the resource, or Locational UCAP Seller that sold the resource, may perform an unlimited number of tests during each such period. If none of the tests during a testing period certify full delivery of the megawatt amount of installed capacity the Market Seller committed, or Locational UCAP Seller sold, for such Delivery Year, the Market Seller or Locational UCAP Seller shall be assessed a daily Generation Resource Rating Test Failure Charge for each day from the first day of the Summer or Winter Season in which such resource failed the rating test through the last day of such Delivery Year, provided, however, that such a seller that fails or is expected to fail a rating test may obtain and commit Unforced Capacity from a replacement Capacity Resource meeting the same locational requirements. Such Unforced Capacity may include uncommitted or uncleared Sell Offer blocks from Generation Capacity Resources that were otherwise committed. Any such commitment of replacement capacity shall be effective upon no less than one day's notice to the Office of the Interconnection, and shall reduce the amount of installed capacity committed from the Generation Capacity Resource, that failed or was expected to fail such rating test, in accordance with the determination prescribed by subsection (b) below.

b) Generation Resource Rating Test Failure Charge

The Generation Resource Rating Test Failure Charge shall equal the Daily Deficiency Rate multiplied by the following megawatt quantity, converted to an Unforced Capacity basis using the Generation Capacity Resource's EFORD for the twelve months ending the September 30 last preceding the Delivery Year: (i) the annual average of the installed capacity committed for each day of such Delivery Year as a result of all cleared Sell Offers in all RPM Auctions for such Delivery Year relying on such resource, reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource, minus (ii) the highest installed capacity rating determined for such resource in any test during the relevant testing period. The Daily Deficiency Rate shall equal the Capacity Resource Clearing Price (weighted as necessary to reflect the clearing prices in all RPM Auctions that resulted in installed capacity commitments from such resource), in \$/MW-day, applicable to the Generation Capacity Resource (for purposes of replacement capacity, including Locational UCAP transactions, the applicable Capacity Resource Clearing Price shall be the clearing price for the Locational

Deliverability Area in which such resource is located) plus the greater of (iii) 0.20 times such weighted average Capacity Resource Clearing Price; or (iv) $20/MW-Day, provided, however, if a resource is unavailable during the Delivery Year at less than the level committed in the Market Seller's cleared Sell Offer or Locational UCAP Seller's Locational UCAP sale due to derating, delay, or retirement, then such seller shall not be assessed a charge under this section to the extent (i.e., for the same megawatts and time period) that such seller is assessed a charge under section 8 for such unavailability. If a single resource is the basis for installed capacity commitments of multiple Capacity Market Sellers or Locational UCAP Sellers, the installed capacity shortfall determined under (i) and (ii) above shall be assessed upon such sellers on a pro-rata basis in accordance with the megawatts of capacity from such resource in their cleared Sell Offers, Locational UCAP sales, or other commitment as replacement capacity.

c) Allocation of Revenue Collected from Generation Resource Rating Test Failure Charges.

The revenue collected from Generation Resource Rating Test Failure Charges shall be distributed on a pro-rata basis to LSEs that were charged a Locational Reliability Charge for the Delivery Year for which the Generation Resource Rating Test Failure Charge was assessed. The charges shall be allocated on a pro-rata basis to LSEs based on their Daily Unforced Capacity Obligation.

Effective Date: 9/17/2010

8. CAPACITY RESOURCE DEFICIENCY CHARGE

8.1

A Capacity Resource Deficiency Charge shall be assessed on any Capacity Market Seller that commits a Capacity Resource, and on any Locational UCAP Seller that sells Locational UCAP for a Delivery Year based on a Generation Capacity Resource, for a Delivery Year that is unable or unavailable to deliver Unforced Capacity for all or any part of such Delivery Year for any reason, including but not limited to the following, and that does not obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resource, Extended Summer Demand Resource, or Limited Demand Resource) in the megawatt quantity required to satisfy the capacity committed from such resource by such seller as a result of all cleared Sell Offers from such seller based on such resource in any RPM Auctions for such Delivery Year, the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource:

a) Unit Derating – Such Capacity Resource is a Generation Capacity Resource and its capacity value is derated prior to or during the Delivery Year;

b) EFORD Increase – Such Capacity Resource is a Generation Capacity Resource and the EFORD value determined for such resource at least two (2) months prior to the Third Incremental Auction is higher than the EFORD value submitted in the Capacity Market Seller's cleared Sell Offer;

c) External Generation Resource – Such Capacity Resource is an Existing Generation Capacity Resource that is located outside of the PJM Control Area and arrangements for the firm delivery of the output of such resource to the interface with the PJM Region are not in place for such resource prior to the start of the Delivery Year;

d) Planned Generation Resource – Such Capacity Resource is a Planned Generation Capacity Resource and Interconnection Service has not commenced as to such resource prior to the start of the Delivery Year;

e) Planned Demand Resource - Such Capacity Resource is a Planned Demand Resource or an Energy Efficiency Resource and the associated demand response program or energy efficiency measure is not installed prior to the start of the Delivery Year; or

f) Existing Demand Resource – Such Capacity Resource is an existing Demand Resource or Energy Efficiency Resource and, subject to section 8.4, is not capable of providing the megawatt quantity of load response specified in the cleared Sell Offer for the time periods of availability associated with the product type.

8.2. Capacity Resource Deficiency Charge

The Capacity Resource Deficiency Charge shall equal the Daily Deficiency Rate (as defined in section 7) multiplied by the megawatt quantity of deficiency below the level of capacity committed in such Capacity Market Seller's Sell Offer(s) or bilateral capacity commitments, or Locational UCAP Seller's Locational UCAP sale for each day such seller is deficient.

8.3. Allocation of Revenue Collected from Capacity Resource Deficiency Charges

The revenue collected from the assessment of a Capacity Resource Deficiency Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

8.4 Relief from Charges

A Capacity Market Seller or Locational UCAP Seller that is otherwise subject to the Capacity Resource Deficiency Charge solely as a result of section 8.1(f) may receive relief from such Charge if it demonstrates that the inability to provide the level of demand response specified in its Sell Offer is due to the permanent departure (due to plant closure, efficiency gains, or similar reasons) from the Transmission System of load that was relied upon for load response in such Sell Offer; provided, however, that such seller must provide the Office of the Interconnection with all information deemed necessary by the Office of the Interconnection to assess the merits of the request for relief. Such seller shall receive no RPM Auction Credit for the amount of reduction in the committed Existing Demand Resources.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

9. PEAK SEASON MAINTENANCE COMPLIANCE PENALTY CHARGE.

a) Purpose

To preserve and maintain the reliability of the PJM Region and to recognize the impact of planned outages and maintenance outages of Generation Capacity Resources during the Peak Season, each Capacity Market Seller that commits a Generation Capacity Resource for a Delivery Year, and each Locational UCAP Seller that sells Locational UCAP from a Generation Capacity Resource for a Delivery Year, must ensure that such Generation Capacity Resource has available sufficient Unforced Capacity during the Peak Season to satisfy the megawatt amount committed from such resource as a result of all Sell Offers by such seller based on such resource in any RPM Auctions for such Delivery Year the reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and the increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource.

b) Peak Season Requirement

To the extent the Generation Capacity Resource will not be available due to a planned or maintenance outage that occurs during the Peak Season without the approval of the Office of the Interconnection, the Capacity Market Seller or Locational UCAP Seller must obtain replacement Unforced Capacity meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resources) from a Capacity Resource that is not already committed for such Delivery Year and that meets all characteristics specified in the Sell Offer or Locational UCAP transaction, including the megawatt quantity of Unforced Capacity committed for such Delivery Year (with such Unforced Capacity, in the case of a Generation Capacity Resource, determined on the basis of such Generation Capacity Resource's EFORD for the twelve months ending on the September 30 last preceding the Delivery Year), or otherwise pay a Peak Season Maintenance Compliance Penalty Charge. The Capacity Market Seller or Locational UCAP Seller shall commit such replacement Capacity Resource in accordance with the procedure set forth in the PJM Manuals.

c) Peak Season Planned and Maintenance Outages

The Office of the Interconnection shall adopt and maintain rules and procedures for determining the allowable Peak Season planned and maintenance outages.

d) Peak Season Maintenance Compliance Penalty Charge

The Peak Season Maintenance Compliance Penalty Charge shall equal the Daily Deficiency Rate (as defined in section 7) multiplied by the unforced value of a positive shortfall calculated for the capacity committed for each day during the Peak Season that such resource is out-of-service on a maintenance outage that is not authorized by the Office of the Interconnection. The shortfall shall equal (i) the annual average of the installed capacity committed for each day of such Delivery Year as a result of all cleared Sell Offers in all RPM Auctions for such Delivery Year relying on such resource, reduction in any such commitment for such resource to the extent and for the time period of any replacement capacity committed in lieu of such resource, and increase in any such commitment for such resource to the extent and for the time period that such resource is committed as replacement capacity for any other resource, minus (ii) the summer net dependable rating minus the amount of capacity out-of-service on unapproved planned or maintenance outage on a peak season day.

e) Allocation of Revenue Collected from Peak Season Maintenance Compliance Penalty Charges

The revenue collected from assessment of a Peak Season Maintenance Compliance Penalty Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which the Capacity Resource Deficiency Charge was assessed. Such revenues shall be distributed on a pro-rata basis to all such LSEs based on their Daily Unforced Capacity Obligation.

Effective Date: 7/14/2011 - Docket #: ER11-4040-000

10. PEAK-HOUR-PERIOD AVAILABILITY CHARGES AND CREDITS

(a) To preserve and maintain the reliability of the PJM Region and to encourage Capacity Market Sellers and Locational UCAP Sellers to maintain the availability of Generation Capacity Resources during critical peak hours of the Delivery Year, each Capacity Market Seller that commits a Generation Capacity Resource for a Delivery Year, and each Locational UCAP Seller that sells Locational UCAP from a Generation Capacity Resource for a Delivery Year, shall be credited or charged to the extent the critical peak-period availability of its committed Generation Capacity Resources exceeds or falls short, respectively, of the expected availability of such resources. Charges and credits hereunder shall not apply to wind or solar resources.

(b) Critical peak periods for purposes of this assessment ("Peak-Hour Periods") shall be the hour ending 1500 local prevailing time through the hour ending 1900 local prevailing time on any day during the calendar months of June through August that is not a Saturday, Sunday, or federal holiday, and the hour ending 800 local prevailing time through the hour ending 900 local prevailing time and the hour ending 1900 local prevailing time through the hour ending 2000 local prevailing time on any day during the calendar months of January and February that is not a Saturday, Sunday or federal holiday.

c) Peak-Period Equivalent Forced Outage Rate and Peak-Period Capacity Calculations

The Peak-Period Equivalent Forced Outage Rate shall be calculated for Peak-Hour Periods based on the following formula:

EFORP (%) = (FOH + EFPOH) / (SH + FOH)

where

FOH = full forced outage hours when the unit was called upon, excluding those outages deemed as OMC (as defined below);

EFPOH = equivalent forced partial outage hours when the unit was called upon, excluding those outages deemed as OMC (as defined below); and

SH = service hours as defined pursuant to NERC GADS standards.

The Peak-Period Capacity of a Generation Capacity Resource shall be calculated as follows:

PCAP = ICAP * (1.0 - $EFOR_P$)

where

ICAP = the installed capacity rating of such Generation Capacity Resource

d) Determination of Expected $EFOR_P$ and PCAP for Generation Capacity Resources

For each Delivery Year, the expected $EFOR_P$ and PCAP of each Generation Capacity Resource committed to serve load in such Delivery Year shall be the EFORD and UCAP, respectively, calculated on a rolling-average basis using such resource's service history during the five consecutive annual periods of twelve consecutive months ending September 30 last preceding such Delivery Year. Such $EFOR_D$ and UCAP shall be determined in accordance with Schedule 5 of the Reliability Assurance Agreement, which excludes (for purposes of Capacity Resource UCAP calculations) outages deemed outside management control in accordance with the standards and guidelines of NERC, as defined in the Generating Availability Data System, Data Reporting Instructions in Attachment K or its successor ("Outside Plant Management Control" or "OMC").

(e) For each Delivery Year, the actual $EFOR_P$ and PCAP of each Generation Capacity Resource shall be calculated during the Peak-Hour Periods of such Delivery Year, provided however, that such calculation shall not include any day such a resource was unavailable if such unavailability resulted in a charge or penalty due to delay, cancellation, retirement, de-rating, or rating test failure. The full or partial forced outage hours when called upon shall be those outage hours during which the cost-based offer for energy from the resource would have been less than the applicable Locational Marginal Price for such resource, or when the Office of the Interconnection would have called upon the resource (absent the outage) for Operating Reserves, in both cases as determined by the Office of the Interconnection in accordance with the procedures specified in the PJM Manuals (including, without limitation, respecting such unit's current operating constraints). In addition, for single-fueled, natural gas-fired units, a failure to perform during the winter Peak-Hour Period shall be excused for purposes of this section if the Capacity Market Seller, or Locational UCAP Seller, as applicable, can demonstrate to the Office of the Interconnection that such failure was due to non-availability of gas to supply the unit.

(f) If the calculation under subsection (e) for any Generation Capacity Resource for a Delivery Year results in fewer than fifty total Service Hours during Peak Hours, then the actual EFORP for purposes of such calculation shall be the lower of the resource's $EFOR_D$ (based on Delivery Year outage data) and its $EFOR_P$ and the actual PCAP for purposes of such calculation shall be, respectively, the resource's UCAP or its PCAP.

(g) For each Delivery Year, the excess or shortfall in Peak-Hour Period availability for each Generation Capacity Resource shall be determined by comparing such resource's expected and actual PCAP, subject to the limitation under subsection (i) below. The net Peak-Hour Period availability shortfall or excess for each Capacity Market Seller and FRR Entity in each Locational Deliverability Area shall be the net of the shortfalls and excesses of all Generation Capacity Resources in such Locational Deliverability Area committed by such Capacity Market Seller or Locational UCAP Seller for such Delivery Year. If there is a net positive Peak Hour Period availability shortfall in the LDA for such committed resources in the LDA, the sum of the excesses of all Generation Capacity Resources in such Locational Deliverability Area owned or controlled by such Capacity Market Seller, available for the Delivery Year but not committed for such Delivery Year, and satisfying all obligations of a committed Capacity Resource for such Delivery Year shall be used to reduce the net positive

Peak Hour Period availability shortfall in the LDA of committed resources by the amount of the sum of the excesses of such available uncommitted resources; however, such reduction shall not result in a net Peak Hour Period availability excess in the LDA.

(h) As to any Generation Capacity Resource experiencing or expected to experience a full or partial outage during any Peak-Hour Period that would or could result in a shortfall under subsection (g) above, a Capacity Market Seller or Locational UCAP Seller may obtain and commit Unforced Capacity from a replacement Capacity Resource (not previously committed) meeting the same locational requirements and same or better temporal availability characteristics (i.e., Annual Resources) as such resource. Such Unforced Capacity shall be recognized for purposes of this section prospectively from the effective date of commitment of such replacement resource, and to the extent such replacement Unforced Capacity thereafter is available during Peak-Hour Periods, any shortfall that otherwise would have been calculated shall be reduced to that extent. Any such commitment of replacement capacity shall be effective upon no less than one day's notice to the Office of the Interconnection.

(i) The shortfall determined for any Generation Capacity Resource shall not exceed an amount equal to 0.50 times the Unforced Capacity of such resource; provided, however, that if such limitation is triggered as to any Generation Capacity Resource for a Delivery Year, then the decimal multiplier for this calculation as to such resource in the immediately succeeding Delivery Year shall be increased to 0.75, and if such limitation again is triggered in such succeeding Delivery Year, then the multiplier shall be increased to 1.00. The multiplier shall remain at either such elevated level for each succeeding Delivery Year until the shortfall experienced by such resource is less than 0.50 times the Unforced Capacity of such resource for three consecutive Delivery Years.

(j) A Peak-Hour Period Availability Charge shall be assessed on each Capacity Market Seller or Locational UCAP Seller with a net shortfall in PCAP in an LDA, where such charge is equal to such shortfall times the Capacity Resource Clearing Price determined for such Locational Deliverability Area for such Delivery Year.

(k) The revenues from such charges shall be distributed to the Capacity Market Sellers, Locational UCAP Sellers, and FRR Entities that committed Generation Capacity Resources, in such Locational Deliverability Area that have net excess PCAP for such Delivery Year, provided however that any such seller shall be paid no more than the product of such seller's net excess PCAP times the Capacity Clearing Price determined for such Locational Deliverability Area for such Delivery Year. Any excess revenues remaining after such distribution shall be distributed on a pro-rata basis to all LSEs in the Zone that were charged the same Locational Reliability Charge for the Delivery Year for which the Peak Hour Availability Charge was assessed, and to all FRR Entities in the Zone that are LSEs and whose FRR Capacity Plan resources over-performed in the Delivery Year, on a pro-rata basis in accordance with each LSE's Daily Unforced Capacity Obligation.

(l) The Office of the Interconnection shall provide estimated charges and credits based on the summer Peak-Hour Periods within three calendar months after the end of the summer period. Final charges and credits for the Delivery Year shall be billed within three calendar months following the end of the Delivery Year.

Effective Date: 2/1/2011 - Docket #: ER11-4143-000

11. DEMAND RESOURCE AND ILR COMPLIANCE PENALTY CHARGE

(a) The Office of the Interconnection shall separately evaluate compliance of each Demand Resource committed and each nominated ILR resource certified for a Delivery Year, in accordance with procedures set forth in the PJM Manuals. The compliance is evaluated separately by event in each Zone for Demand Resources and ILR resources dispatched by the Office of Interconnection. To the extent an ILR resource or Demand Resource cannot respond, another ILR resource or Demand Resource in the same geographic location defined by the PJM dispatch instruction with the same designated lead time and comparable capacity commitment may be substituted. Any Demand Resource or ILR resource used as a substitute during an event will have the same obligation to respond to future event(s) as if it did not respond to such event. Capacity Market Sellers that committed Demand Resources, Locational UCAP Sellers that sold Demand Resources, and ILR Providers that nominated ILR for a Delivery Year that cannot demonstrate the hourly performance of such resource in real-time based on the capacity commitment or ILR certification shall be assessed a Demand Resource and ILR Compliance Penalty Charge; provided, however, that such under compliance shall be determined on an aggregate basis for all Demand Resources and ILR committed by the same Capacity Market Seller, same Locational UCAP Seller, or same ILR Provider in a single Zone. To the extent a Capacity Market Seller is also an ILR Provider, compliance of all Demand Resources committed and ILR resources certified in the same Zone will be evaluated in aggregate.

(b) The Demand Resource and ILR Compliance Penalty Charge for a Capacity Market Seller/ILR Provider in a Zone for the on-peak period, which includes all hours specified in the Reliability Assurance Agreement definition of the Limited Demand Resource, shall equal the lesser of (1/the number of load management events during the year, or 0.50) times the weighted daily revenue rate for such seller/provider, multiplied by the net under-compliance in such on-peak period, if any, for such seller/provider resulting from all resources it has committed and ILR it has certified for such Delivery Year for such Zone for each load reduction event called by the Office of the Interconnection. The Demand Resource and ILR Compliance Penalty Charge for a Capacity Market Seller/ILR Provider in a Zone for the off-peak period, which includes all hours specified in the Reliability Assurance Agreement definitions of Extended Summer Demand Resource or Annual Demand Resource, but does not included in the on-peak period, shall equal 1/52 times the weighted daily revenue rate for such seller/provider, multiplied by the net undercompliance in such off-peak period, if any, for such seller/provider resulting from all resources it has committed and ILR it has certified for such Delivery Year for such Zone for each load reduction event called by the Office of the Interconnection. If a load management event is comprised of both an on-peak period and an off-peak period then such Demand Resource and ILR Compliance Penalty Charge will be the higher of the charges calculated under the prior two sentences. The total Compliance Penalty Charge for the Delivery Year is not to exceed the annual revenue received for such resources. The net undercompliance for each such load reduction event shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable DR Factor and Forecast Pool Requirement: (i) the megawatts of load reduction capability committed and/or ILR certified by such seller/provider on the day of the Load Management event minus (ii) the megawatts of load reduction actually provided by all such Demand Resources and ILR during such reduction event. A provider's net undercompliance in a Zone shall be reduced by the provider's total amount of Capacity Resource deficiency shortfalls on the day of the Load Management event, determined pursuant to section 8 of Attachment DD of this Tariff, in a Zone for the provider's committed Demand Resources. The daily revenue rate for a Demand Resource shall be the Resource Clearing Price that the resource received in the auction in which it cleared, including any adjustment pursuant to Attachment DD-1, section C of this Tariff. The daily revenue rate for an ILR resource shall be the Final Zonal ILR Price. The weighted daily revenue rate for a Capacity Market Seller/ILR Provider shall be the average rate for all cleared Demand Resources and certified ILR, weighted by the megawatts cleared or certified at each price. The total charge per megawatt that may be assessed on a Capacity Market Seller/ILR Provider in a Delivery Year shall be capped at the weighted daily revenue rate the Capacity Market Seller/ILR Provider would receive in the Delivery Year. The Demand Resource and ILR Compliance Penalty Charges for a Load Management event are assessed daily and initially billed by the later of the month of October during such Delivery Year or the third billing month following the Load Management event that gave rise to such charge. The initial billing for a Load Management event will reflect the amounts due from the start of the Delivery Year to the last day that is reflected in the initial billing. The remaining charges for such Load Management event will be assessed daily and billed monthly through the remainder of the Delivery Year.

c) Daily revenues from assessment of a Demand Resource and ILR Compliance Penalty Charge shall be distributed on a pro-rata basis to Demand Resource Providers, Locational UCAP Sellers, and ILR Providers that provided load reductions in excess of the amount such resources were committed or certified to provide. Such revenue distribution, however, shall not exceed for any Capacity Market Seller/ILR Provider the quantity of excess megawatts provided by such Capacity Market Seller/ILR Provider during a single event times 0.20 times the weighted daily revenue rate for such Capacity Market Seller/ILR Provider. To the extent any such revenues remain after such distribution, the remaining revenues shall be distributed to LSEs based on each LSE's Daily Unforced Capacity Obligation.

Effective Date: 12/30/2011 - Docket #: ER12-271-000

11A LOAD MANAGEMENT AND DEMAND RESOURCES TEST FAILURE CHARGE

a) Beginning with the Delivery Year that commences on June 1, 2009, Capacity Market Sellers that commit Demand Resources and ILR Providers may be charged to the extent their committed resources or certified ILR fail performance tests, as set forth herein.

b)

(i) For ILR or for Limited Demand Resources: If a Limited Demand Resource committed or an ILR certified by a Capacity Market Seller/ILR Provider is not dispatched by the Office of the Interconnection for a load management event prior to August 15 of the relevant Delivery Year, then such resource must demonstrate that it was tested as described below in (ii), in a zone for a one-hour period during any hour when a PJM load management event may be called between June 1 and September 30, inclusive. If a Limited Demand Resource committed or an ILR certified by a Capacity Market Seller/ILR Provider is dispatched by the Office of the Interconnection for a PJM load management event in a zone between August 16 and September 30, no test will be required. If a Limited Demand Resource committed or an ILR certified by a Capacity Market Seller/ILR Provider is dispatched by the Office of the Interconnection for a PJM load management event in a zone between June 1 and September 30, inclusive, then Load Management and Demand Resources Test Failure Charges will not be assessed.

For Annual Demand Resources: if an Annual Demand Resource is not dispatched by the Office of the Interconnection for a load management event in a Delivery Year, then the Annual Demand Resource committed by a Capacity Market Seller must demonstrate that the Annual Demand Resource committed in a zone was tested as described below in (iii), for a one-hour period during any hour when a PJM load management event may be called during June through October or the following May of the relevant Delivery Year. If an Annual Demand Resource is dispatched by the Office of the Interconnection for a load management event during the Delivery Year, then no test will be required.

For Extended Summer Demand Resources: if an Extended Summer Demand Resource is not dispatched by the Office of the Interconnection for a load management event during June through October or the following May, then the Extended Summer Demand

Resource committed by a Capacity Market Seller must demonstrate that the Extended Summer Demand Resource was tested as described below in (iii), for a one-hour period during any hour when a PJM load management event may be called during June through October or the following May of the relevant Delivery Year.

(ii) All resources in a zone must be tested simultaneously except that, when less than 25 percent (by megawatts) of a provider's total resources in a zone fail a test, the provider may conduct a re-test limited to all resources that failed the prior test, provided that such re-test must be at the same time of day and under approximately the same weather conditions as the prior test, and provided further that all affiliated resources must test simultaneously, where affiliated means resources that have any ability to shift load and are owned or controlled by the same entity. If less than 25 percent of resources fail the test and the provider chooses to conduct a retest, the provider may elect to maintain the performance compliance result for resource(s) achieved during the test if provider: (1) notifies the Office of the Interconnection 48 hours prior to the retest under this election; and (2) the provider retests affiliated resources under this election as set forth in the PJM Manual.

c) a Capacity Market Seller/ILR Provider that committed Demand Resources and/or certified ILR shall be assessed a Load Management and Demand Resources Test Failure Charge equal to the net capability testing shortfall in a Zone during such test in the aggregate of all of such Seller's/Provider's Demand Resources/ILR in such Zone times the Load Management and Demand Resources Test Failure Charge Rate. The net capability testing shortfall in such Zone shall be the following megawatt quantity, converted to an Unforced Capacity basis using the applicable DR Factor and Forecast Pool Requirement: (i) the summer daily average of the megawatts of load reduction capability committed and/or ILR certified by such seller/provider in such Zone minus (ii) the megawatts of load reduction actually provided by all such Demand Resources and ILR in such Zone during such test. The net capability testing shortfall in such Zone shall be reduced by the provider's summer daily average of the Capacity Resource deficiency shortfalls, determined pursuant to section 8 of Attachment DD of this Tariff, in such Zone for all of the provider's committed Demand Resources.

d) the Load Management and Demand Resources Test Failure Charge Rate shall equal such Seller/Provider's Weighted Annual Revenue Rate in such Zone plus the greater of (0.20 times the Weighted Annual Revenue Rate in such Zone or $20/MW-day) times the number of days in the Delivery Year. Such charge shall be assessed daily and charged monthly (or otherwise in accordance with customary PJM billing practices in effect at the time); provided, however, that a lump sum payment may be required to reflect amounts due, as a result of a test failure, from the start of the Delivery Year to the day that charges are reflected in regular billing.

e) revenues collected from assessment of Load Management and Demand Resources Test Failure Charges shall be distributed to Load Serving Entities that were charged a Locational Reliability Charge for the Delivery Year for which the Load Management and Demand Resources Test Failure Charge was assessed, pro-rata based on such Load Serving Entities' Daily Unforced Capacity Obligations.

Effective Date: 4/18/2011 - Docket #: ER11-2898-000

12. QUALIFYING TRANSMISSION UPGRADE COMPLIANCE PENALTY CHARGE

If a Qualifying Transmission Upgrade forming the basis of a Sell Offer that cleared in the Base Residual Auction for a Delivery Year is not in service at the commencement of such Delivery Year, and the Capacity Market Seller does not obtain replacement Capacity Resources in the LDA for which such upgrade was to increase CETL, such seller shall pay a compliance penalty charge for each day such upgrade is delayed during such Delivery Year equal to the megawatt quantity of Import Capability cleared in the Base Residual Auction based on such upgrade, multiplied by the greater of: (i) two times the Locational Price Adder of the LDA into which the Qualifying Transmission Upgrade is cleared, in $/MW-day; or (ii) the Net Cost of New Entry less the clearing price in the LDA from which CETL was increased. The revenue collected from the assessment of Qualifying Transmission Upgrade Compliance Penalty Charges shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which such charge was assessed. Such revenues shall be distributed on a pro-rata basis to such LSEs based on their Daily Unforced Capacity Obligations.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

13. EMERGENCY PROCEDURE CHARGE

13.1 Application of the Emergency Procedure Charge

Following an Emergency, the compliance during the period of such Emergency with the instructions of the Office of the Interconnection of: (a) each Capacity Market Seller that committed Capacity Resources, and each Locational UCAP Seller that sold Locational UCAP, for such period; and (b) each ILR Provider responsible for ILR certified for such period, shall be evaluated as recommended by the Markets and Reliability Committee and directed by the PJM Board. If, based on such evaluation, it is determined that a Capacity Market Seller, Locational UCAP Seller, or ILR Provider refused to comply with, or otherwise failed to employ its best efforts to comply with, the instructions of the Office of the Interconnection to implement PJM emergency procedures, then such Capacity Market Seller, Locational UCAP Seller, or ILR Provider shall pay an Emergency Procedure Charge.

13.2 Emergency Procedure Charge

The Emergency Procedure Charge shall equal the number of days in the Delivery Year multiplied by the Daily Deficiency Rate for such Delivery Year times each megawatt of a Demand Resource or ILR that was not implemented as directed, and each megawatt of a Generation Capacity Resource that was not made available as directed despite being capable of producing energy at the time, and that is deliverable to the PJM Region in the case of a Generation Capacity Resource located outside the PJM Region.

13.3 Allocation of Revenue from Emergency Procedure Charges

The revenue collected from assessment of an Emergency Procedure Charge shall be distributed on a pro-rata basis to all LSEs that were charged a Locational Reliability Charge for the day for which the Emergency Procedure Charge was assessed. The charges shall be allocated on a pro-rata basis to all such LSEs based on their Daily Unforced Capacity Obligation.

Effective Date: 2/18/2012 - Docket #: ER12-636-000

14. CONVERSION OF CAPACITY CREDITS FROM PRIOR CAPACITY ADEQUACY REGIME

14.1 Purpose

Capacity Credits shall not be accepted as satisfaction of the Daily Unforced Capacity Obligation of any LSE. Parties to Capacity Credit transactions may agree bilaterally to convert such transactions on a basis that permits them to clear in a Reliability Pricing Model Auction, or may settle such transactions financially as described in section 14.2.

14.2 Settlement

For the 2007/2008 Delivery Year, only Capacity Credits confirmed by the Office of the Interconnection to have been entered into prior to April 1, 2006 will be settled based on the marginal value of system capacity ($/MW-day) as determined under section 5.14(a) in the Base Residual Auction for such Delivery Year, plus any Locational Price Adder determined in such auction for the Locational Deliverability Area that corresponds to the Mid-Atlantic Region plus the Allegheny Power System Zone. The party that purchased such Capacity Credit shall receive this value multiplied by the megawatt quantity of the Capacity Credit, for the duration of such transaction. The party that sold such Capacity Credit shall be assessed this value, multiplied by the megawatt quantity of the Capacity Credit, for the duration of such transaction. For the 2008/2009 Delivery Year, and thereafter, Capacity Credits will be settled based on the marginal value of system capacity ($/MW-day) as determined under section 5.14(a) in the Base Residual Auction for such Delivery Year. The party that purchased such Capacity Credit shall receive this value multiplied by the megawatt quantity of the Capacity Credit, for the duration of the transaction. The party that sold such Capacity Credit will be assessed this value multiplied by the megawatt quantity of the Capacity Credit, for the duration of the transaction.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

15. COORDINATION WITH ECONOMIC PLANNING PROCESS

Following each Base Residual Auction, the Office of the Interconnection shall review each LDA that has a Locational Price Adder to determine if Planned Generation Capacity Resources, Planned Demand Resources, or Qualifying Transmission Upgrades submitted Sell Offers that cleared in such auction. If a Locational Price Adder results from the clearing of an LDA for two consecutive Base Residual Auctions, and no such planned resources or upgrades clear in such auctions for such LDA, then the Office of the Interconnection shall evaluate in the RTEP process the costs and benefits of a transmission upgrade that would reduce to zero the Locational Price Adder for such LDA. Such evaluation will compare the cost of the upgrade over ten years against the value of elimination of the Locational Price Adder over such period. If such upgrade is found to be feasible and beneficial, it shall be included in the RTEP as soon as practicable. The annual costs of such upgrade shall be allocated as specified in Schedule 6 of the Operating Agreement.

Effective Date: 2/18/2012 - Docket #: ER12-636-001

16. RELIABILITY BACKSTOP

16.1. Purpose

The Reliability Backstop provides a mechanism to resolve reliability criteria violations caused by: (a) lack of sufficient capacity committed through the Reliability Pricing Model Auctions; or (b) *near-term transmission deliverability violations identified after the Base Residual Auction is* conducted. These backstop mechanisms are intended to guarantee that sufficient generation, transmission and demand response solutions will be available to preserve system reliability. The backstop mechanisms are based on specific triggers that signal a need for a targeted solution to a reliability problem that was not resolved by the long-term commitment of Capacity Resources through Self-Supply or the Reliability Pricing Model Auctions.

16.2 Investigation of Capacity Shortfall

If the total Unforced Capacity of Capacity Resources committed for a Delivery Year following the Base Residual Auction equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Region Installed Reserve Margin, the Office of the Interconnection shall investigate the cause for the shortage, and recommend corrective action, including, without limitation, adjusting the Cost of New Entry to the extent determined necessary by such investigation, or addressing other barriers to entry identified by such investigation. No Reliability Backstop Auction will be conducted to address such a shortfall unless it occurs in the Base Residual Auctions for three consecutive Delivery Years.

16.3 Triggering Conditions

a) Either of the following two conditions will trigger reliability backstop measures provided in this section, as described below:

i) If the total Unforced Capacity of all Capacity Resources committed through Self-Supply or the Base Residual Auctions for three consecutive Delivery Years, equates to an installed reserve margin that is more than one percentage point lower than the approved PJM Region Installed Reserve Margin, the Office of the Interconnection will declare a capacity shortage and make a filing with FERC for approval to conduct a Reliability Backstop Auction. Upon receipt of such approval, the Office of the Interconnection will conduct a Reliability Backstop Auction in accordance with Section 16.4.

ii) If the total Unforced Capacity of all Base Load Generation Resources committed in a Base Residual Auction for a Delivery Year is less than the forecasted minimum hourly load calculated by the Office of the Interconnection for such Delivery Year, the Office of the Interconnection will investigate the cause of shortfall. If such a shortfall occurs in the Base Residual Auctions for three consecutive Delivery Years, the Office of the Interconnection shall declare a capacity shortage and make a filing with FERC for approval to conduct a Reliability Backstop Auction. Upon receipt of such approval, the Office of the Interconnection will conduct a Reliability Backstop Auction in accordance with Section 16.4.

b) In addition to the foregoing events that trigger reliability backstop measures, if a near-term, i.e., later in time than the conduct of the Base Residual Auction for a Delivery Year, transmission criteria violation caused by an announced generation resource deactivation is identified by the regional transmission reliability planning analysis performed by the Office of the Interconnection in accordance with Part V of this Tariff, the Office of the Interconnection will identify the necessary transmission upgrade. In accordance with such rules, such generation resource may remain in service until the transmission upgrade is installed. No Reliability Backstop Auction will be conducted.

16.4. Reliability Backstop Auction

a) Scope of Auction

The Office of the Interconnection shall conduct each Reliability Backstop Auction to commit additional Generation Capacity Resources, or in the case of an auction triggered by section 16.3(a)(ii), additional Base Load Generation Resources to the PJM Region to resolve the system-wide reliability criteria violation that triggered the need for such auction. Capacity Resources committed in a Reliability Backstop Auction for a Delivery Year shall not include any Planned Generation Capacity Resources previously committed in the Base Residual Auction for such Delivery Year. The Reliability Backstop Auction shall obtain commitments of additional Generation Capacity Resources (or, as applicable, additional Base Load Generation Resources) for a term of up to fifteen (15) Delivery Years. If a Reliability Backstop Auction is required, the offer period for such auction shall commence, subject to FERC approval as specified above, no later than four months after the Base Residual Auction in which the third consecutive Capacity Resource shortfall occurs. Upon verification and notification by the PJM Board of Managers that a Reliability Backstop Auction is required, the Office of the Interconnection shall post notification that a Reliability Backstop Auction is to be held. Upon such notification, the offer period shall commence, and shall remain open for six (6) months. PJMSettlement shall be the Counterparty to the capacity transaction resulting from committed Capacity Resources clearing the Reliability Backstop Auction.

b) Sell Offers

Each Sell Offer shall specify the following information, as further specified in the PJM Manuals:

- the minimum price in $/MW-day required by the Capacity Market Seller to provide additional Unforced Capacity from a Generation Capacity Resource (or from a Base Load Generation Resource, in the case of an auction triggered by section 16.3(a)(ii));

- the megawatts of Unforced Capacity to be provided by such resource;

- the specific location of the proposed plant;

- all information required from a Generation Interconnection Customer by Part IV of this Tariff and the PJM Manuals;

- general plant technical specifications, as specified in the PJM Manuals;

- the term of cost recovery ("Backstop Period") requested, not to exceed 15 years; and

- the first full Delivery Year for which such resource shall be available, which shall also be the first year of the Backstop Period.

Each Generation Capacity Resource (or Base Load Generation Resource) accepted in a Reliability Backstop Auction shall comply with the procedures for new generation interconnection in Part IV of this Tariff, and each such resource shall be responsible for satisfying all capability and deliverability requirements for Capacity Resources, pursuant to the Reliability Assurance Agreement.

c) Submission of Sell Offers

The Sell Offer period shall begin at 00:01 Eastern Prevailing Time on the date specified by the Office of the Interconnection in the notification posting and shall end at 23:59 Eastern Prevailing Time six calendar months after such date. Sell offers shall be submitted during such period in writing to the Office of the Interconnection, and shall conform to the submission procedures as specified in the PJM Manuals. The Office of the Interconnection shall confirm in writing the receipt of each Sell Offer, within two weeks after receipt of each such offer.

d) Posting of Information by the Office of the Interconnection

Upon notification by the PJM Board of Managers that a Reliability Backstop Auction will be conducted, the Office of the Interconnection shall post the following information:

- System condition that necessitates a Reliability Backstop Auction;

- Megawatt quantity of Unforced Capacity required from additional Generation Capacity Resources, or from additional Base Load Generation Resources;

- Date by which the resources must be capable of delivering Unforced Capacity;

- Any other required specifications for the additional Unforced Capacity sought through such auction.

e) Conduct of the Reliability Backstop Auction

i) Auction Clearing Procedure

The Reliability Backstop Auction shall select the Sell Offer or combination of Sell Offers that that satisfies the requirements posted by the Office of the Interconnection at the lowest offer price(s). If more than one Sell Offer must be selected to satisfy the specified requirements, the Sell Offers shall be selected in rank order from lowest offer price to highest offer price until the requirement is satisfied. In the event two or more Sell Offers specify the same offer price, and fewer than all of such offers are needed to satisfy the specified requirements, the Office of the Interconnection shall select the Sell Offer(s) proposing Generation Capacity Resource(s), or, as applicable, Base Load Generation Resource(s) that will best satisfy overall reliability requirements for the PJM Region, as determined by the Office of the Interconnection using transmission reliability analysis.

ii) Market Settlement

Pursuant to the agreement specified below, each Capacity Market Seller submitting a Sell Offer that is accepted in a Reliability Backstop Auction shall be paid by PJMSettlement the offer price in such Sell Offer for each MW-day in the Backstop Period, less any payments the Capacity Market Seller is entitled to receive pursuant to section 5 of this Attachment as a result of Sell Offers submitted with respect to such Generation Capacity Resource in any Base Residual Auction or Incremental Auction, including, without limitation, payments of Capacity Resource Clearing Prices (including for Self-Supply) and Resource Make-Whole Payments; and less any payments the Capacity Market Seller is entitled to receive for energy or ancillary services pursuant to Schedule 1 of the Operating Agreement with respect to services provided by such resource, net of the Variable Operations and Maintenance costs of such resource, as determined in accordance with the PJM Manuals.

PJM shall recover the costs of any such payments to Capacity Market Sellers for such resources through a charge, in addition to the Locational Reliability Charge, assessed on all LSEs in the PJM Region, pro rata based on each such LSE's Daily Unforced Capacity Obligations in all LDAs in which such LSE serves load. PJMSettlement shall be the Counterparty to the LSE's obligation to pay, and payment of, such charges.

iii) Standard Contract Provisions

PJMSettlement, will enter into an agreement with each Capacity Market Seller that submitted an accepted Sell Offer in any Reliability Backstop Auction providing for the payments specified above. Such agreement shall include the provisions and address the standards set forth in Section 16.4(b), and shall include such other terms and conditions as are customary in the industry, as specified in the PJM Manuals.

f) FERC Approval

Any such agreement shall provide that it shall be filed with FERC as a rate schedule pursuant to section 205 of the Federal Power Act, and that the effectiveness of such agreement shall be conditioned on receipt of FERC acceptance or approval of such agreement.

16.5 Must Offer into Base Residual Auction

All Capacity Market Sellers submitting a Sell Offer that is selected in a Reliability Backstop Auction must offer all Unforced Capacity of the Generation Capacity Resource underlying such Sell Offer into the Base Residual Auctions conducted subsequent to the Reliability Backstop Auction for all Delivery Years in the Backstop Period. The Market Seller shall offer the

Unforced Capacity of such resources into each such auction at zero price, and shall receive the Capacity Resource Clearing Price as determined in each such auction.

16.6 Reliability Backstop Resource Deficiency Charges

(a) Any Capacity Market Seller that submits a Sell Offer that was selected in a Reliability Backstop Auction and that is not able to deliver in a Delivery Year all megawatts of Unforced Capacity specified in the selected Sell Offer, shall not receive any payments that such Capacity Market Seller otherwise would have been eligible to receive for such Delivery Year pursuant to the Reliability Backstop Auction.

(b) Any Capacity Market Seller that submits a Sell Offer that was selected in a Reliability Backstop Auction and that fails to deliver all megawatts of Unforced Capacity specified in the selected Sell Offer at any time during the Backstop Period specified in such Sell Offer must refund all payments received by such Market Seller pursuant to section 16.4(b).

Effective Date: 1/1/2011 - Docket #: ER11-2527-000

17. TRANSITION

17.1 Phase-in of the Reliability Pricing Model

The Reliability Pricing Model shall be phased in during the Transition Period as described below.

17.2 Reliability Pricing Model Auctions Conducted During Transition Period

(a) The Office of the Interconnection shall conduct Base Residual Auctions for each Delivery Year in the Transition Period in accordance with the following schedule:

Delivery Year	Base Residual Auction Held
June 1, 2007 – May 31, 2008	April 2007
June 1, 2008 – May 31, 2009	July 2007
June 1, 2009 – May 31, 2010	October, 2007
June 1, 2010 – May 31, 2011	January, 2008
June 1, 2011 – May 31, 2012	May 2008

b) The Office of the Interconnection shall conduct Incremental Auctions for each Delivery Year in the Transition Period in accordance with the following schedule:

Delivery Year	First Incremental Auction Held	Second Incremental Auction Held If Necessary	Third Incremental Auction Held
June 1, 2007 – May 31, 2008	None Held	None Held	None Held
June 1, 2008 – May 31, 2009	None Held	None Held	January, 2008
June 1, 2009 – May 31, 2010	None Held	April, 2008	January, 2009
June 1, 2010 – May 31, 2011	None Held	April, 2009	January, 2010
June 1, 2011 – May 31, 2012	June 2009	July 2010	February 2011

17.3 Transition Period Locational Deliverability Areas

The Office of the Interconnection shall establish Locational Deliverability Areas during the Transition Period in accordance with the following:

<u>2007/2008, 2008/2009, and 2009/2010 Delivery Years</u>

- o MAAC Region and APS (the zones listed below for Eastern MAAC, Southwestern MAAC and Western MAAC, plus APS)
- o ComEd, AEP, Dayton, Dominion and Duquesne

- Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL & RECO)
- Southwestern MAAC (PEPCO & BG&E)

2010/2011 and subsequent Delivery Years

- MAAC Region
- ComEd, AEP, Dayton, APS, and Duquesne
- Dominion
- Eastern MAAC
- Southwestern MAAC
- Western MAAC (Penelec, MetEd, PPL)
- Penelec
- ComEd
- AEP
- Dayton
- Duquesne
- APSAE
- BG&E
- DPL
- PECO
- PEPCO
- PSE&G
- JCP&L
- MetEd
- PPL
- PSEG northern region (north of Linden substation); and
- DPL southern region (south of Chesapeake and Delaware Canal).

17.4 Transition Period Variable Resource Requirement Curves

During the Transition Period, the Office of the Interconnection shall post on the PJM internet site the Variable Resource Requirement Curves that will apply for each Delivery Year no later than one month prior to the conduct of the Base Residual Auction for such Delivery Year.

17.5 Market Mitigation

The provisions of Section 6 of this Attachment shall apply to all Reliability Pricing Model Auctions conducted during the Transition Period; provided, however, that during the Transition Period, as to a Capacity Market Seller that owns or controls no more than 10,000 megawatts of Unforced Capacity in the PJM Region, the otherwise applicable Market Seller Offer Cap provided in Section 6 shall be increased by up to the following amounts in the following years for any Sell Offer submitted by such a seller in any Unconstrained LDA Group, with respect to no more than 3,000 megawatts of such Unforced Capacity:

(a) $10/MW-day for the 2007-2008 Delivery Year;

(b) $10/MW-day for the 2008-2009 Delivery Year; and

(c) $7.50/MW-day for the 2009-2010 Delivery Year;

For purposes of this provision, the 10,000 megawatt maximum shall apply separately to a Capacity Market Seller's resources subject to state rate-based regulation and resources that are not subject to state rate-based regulation.

17.6 Performance Assessment

Within six months after the end of the fourth Delivery Year, the Office of the Interconnection shall prepare, provide to Members, and file with FERC an assessment of the performance of the Reliability Pricing Model.

Effective Date: 9/17/2010 - Docket #: ER10-2710-000

ATTACHMENT DD-1

Preface: The provisions of this Attachment incorporate into the Tariff for ease of reference the provisions of Schedule 6 of the Reliability Assurance Agreement among Load Serving Entities in the PJM Region. As a result, this Attachment will be modified, subject to FERC approval, so that the terms and conditions set forth herein remain consistent with the corresponding terms and conditions of Schedule 6 of the RAA. Capitalized terms used herein that are not otherwise defined in Attachment DD or elsewhere in this Tariff have the meaning set forth in the RAA.

PROCEDURES FOR DEMAND RESOURCES, ILR, AND ENERGY EFFICIENCY

A. Parties can partially or wholly offset the amounts payable for the Locational Reliability Charge with Demand Resources or ILR that are operated under the direction of the Office of the Interconnection. FRR Entities may reduce their capacity obligations with Demand Resources that are operated under the direction of the Office of the Interconnection and detailed in such entity's FRR Capacity Plan. Demand Resources qualifying under the criteria set forth below may be offered for sale or designated as Self-Supply in the Base Residual Auction, included in an FRR Capacity Plan, or offered for sale in any Incremental Auction, for any Delivery Year for which such resource qualifies. In addition, for Delivery Years through May 31, 2012, resources qualifying under the criteria set forth below may be certified as ILR on behalf of a Party that has not elected the FRR Alternative for a Delivery Year no later than three months prior to the first day of such Delivery Year; provided, however, that for the 2011-2012 Delivery Year only, the ILR certification deadline shall be no later than two months prior to the first day of such Delivery Year. Qualified Demand Resources and ILR generally fall in one of three categories, i.e., Guaranteed Load Drop, Firm Service Level, or Direct Load Control, as further specified in section H and the PJM Manuals. Qualified Demand Resources and ILR may be provided by a Demand Resource Provider or ILR Provider (hereinafter, "Provider"), notwithstanding that such Provider is not a Party to this Agreement. Such Providers must satisfy the requirements in section I and the PJM Manuals.

1. A Party must formally notify, in accordance with the requirements of the PJM Manuals and section G of this schedule as applicable, the Office of the Interconnection of the Demand Resource or ILR that it is placing under the direction of the Office of the Interconnection. A Party must further notify the Office of the Interconnection whether the resource is an ILR resource, a Limited Demand Resource, an Extended Summer Demand Resource or an Annual Demand Resource.

2. A period of no more than 2 hours prior notification must apply to interruptible customers.

3. The initiation of load interruption, upon the request of the Office of the Interconnection, must be within the authority of the dispatchers of the Party. No additional approvals should be required.

4. The initiation of load reduction upon the request of the Office of the Interconnection is considered an emergency action and must be implementable prior to a voltage reduction.

5. An entity offering for sale, designating for self-supply, or including in any FRR Capacity Plan any Planned Demand Resource must demonstrate, in accordance with standards and procedures set forth in the PJM Manuals, that such resource shall have the capability to provide a reduction in demand, or otherwise control load, on or before the start of the Delivery Year for which such resource is committed. Providers of Planned Demand Resources must provide a timeline including the milestones, which demonstrates to PJM's satisfaction that the Planned Demand Resources will be available for the start of the Delivery Year, 15 business days prior to a Base Residual Auction or Incremental Auction. PJM may verify the Provider's adherence to the timetable at any time.

6. Selection of a Demand Resource in an RPM Auction results in commitment of capacity to the PJM Region. Demand Resources that are so committed must be registered to participate in the Full Program Option or as a Capacity Only resource of the Emergency Load Response program and thus available for dispatch during PJM-declared emergency events.

B. The Unforced Capacity value of a Demand Resource and ILR will be determined as:

the product of the Nominated Value of the Demand Resource, or the Nominated Value of the ILR, times the DR Factor, times the Forecast Pool Requirement. Nominated Values shall be determined and reviewed in accordance with sections J and K, respectively, and the PJM Manuals. The DR Factor is a factor established by the PJM Board with the advice of the Members Committee to reflect the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR. Peak load carrying capability is defined to be the peak load that the PJM Region is able to serve at the loss of load expectation defined in the Reliability Principles and Standards. The DR Factor is the increase in the peak load carrying capability in the PJM Region due to Demand Resources and ILR, divided by the total Nominated Value of Demand Resources and ILR in the PJM Region. The DR Factor will be determined using an analytical program that uses a probabilistic approach to determine reliability. The determination of the DR Factor will consider the reliability of Demand Resources and ILR, the number of interruptions, and the total amount of load reduction.

C. Demand Resources offered and cleared in a Base Residual or Incremental Auction shall receive the corresponding Capacity Resource Clearing Price as determined in such auction, in accordance with Attachment DD of the PJM Tariff. For Delivery Years beginning with the Delivery Year that commences on June 1, 2013, any Demand Resources located in a Zone with multiple LDAs shall receive the Capacity Resource Clearing Price applicable to the location of such resource within such Zone, as identified in such resource's offer. Further, the Demand Resource Provider shall register its resource in the same location within the Zone as specified in its cleared sell offer, and shall be subject to deficiency charges under Attachment DD of this Tariff to the extent it fails to provide the resource in such location consistent with its cleared offer. For either of the Delivery Year commencing on June 1, 2010 or commencing on June 1, 2012, if the location of a Demand Resource is not specified by a Seller in the Sell Offer on an individual LDA basis in a Zone with multiple LDAs, then Demand Resources cleared by such Seller will be paid a DR Weighted Zonal Resource Clearing Price, determined as follows: (i) for a Zone that includes non-overlapping LDAs, calculated as the weighted average of the Resource Clearing Prices for such LDAs, weighted by the cleared Demand Resources registered by such Seller in each such LDA; or (ii) for a Zone that contains a smaller LDA within a larger LDA, calculated treating the smaller LDA and the remaining portion of the larger LDA as if they were separate LDAs, and weight-averaging in the same manner as (i) above.

D. Certified ILR resources shall receive the Final Zonal ILR Price.

E. The Party, Electric Distributor, Demand Resource Provider, or ILR Provider that establishes a contractual relationship (by contract or tariff rate) with a customer for load reductions is entitled to receive the compensation specified in sections C and D for a committed Demand Resource or certified ILR, notwithstanding that such provider is not the customer's energy supplier.

F. Any Party hereto shall demonstrate that its Demand Resources or ILR performed during periods when load management procedures were invoked by the Office of the Interconnection. The Office of the Interconnection shall adopt and maintain rules and procedures for verifying the performance of such resources, as set forth in section L and the PJM Manuals. In addition, committed Demand Resources and certified ILR that do not comply with the directions of the Office of the Interconnection to reduce load during an emergency shall be subject to the penalty charge set forth in Attachment DD to the PJM Tariff.

G. Parties may elect to place Demand Resources associated with Behind The Meter Generation under the direction of the Office of the Interconnection for a Delivery Year by submitting a Sell Offer for such resource (as Self Supply, or with an offer price) in the Base Residual Auction for such Delivery Year. This election shall remain in effect for the entirety of such Delivery Year. In the event such an election is made, such Behind The Meter Generation will not be netted from load for the purposes of calculating the Daily Unforced Capacity Obligations under this Agreement.

H. PJM recognizes three types of Demand Resource and ILR:

Direct Load Control (DLC) – Load management that is initiated directly by the Provider's market operations center or its agent, employing a communication signal to cycle equipment (typically water heaters or central air conditioners). DLC programs are qualified based on load research and customer subscription data. Providers may rely on the results of load research studies identified in the PJM Manuals to set the per-participant load reduction for DLC programs. Each Provider relying on DLC load management must periodically update its DLC switch operability rates, in accordance with the PJM Manuals.

Firm Service Level (FSL) – Load management achieved by a customer reducing its load to a pre-determined level (the Firm Service Level), upon notification from the Provider's market operations center or its agent.

Guaranteed Load Drop (GLD) – Load management achieved by a customer reducing its load by a pre-determined amount (the Guaranteed Load Drop), upon notification from the Provider's market operations center or its agent. Typically, the load reduction is achieved through running customer-owned backup generators, or by shutting down process equipment.

For each type of Demand Resource and ILR above, there can be two notification periods:

Step 1 (Short Lead Time) – Demand Resource or ILR which must be fully implemented in one hour or less from the time the PJM dispatcher notifies the market operations center of a curtailment event.

Step 2 (Long Lead Time) – Demand Resource or ILR which requires more than one hour but no more than two hours, from the time the PJM dispatcher notifies the market operations center of a curtailment event, to be fully implemented.

I. Each Provider must satisfy (or contract with another LSE, Provider, or EDC to provide) the following requirements:

Section 1 A point of contact with appropriate backup to ensure single call notification from PJM and timely execution of the notification process;

Section 2 supplemental status reports, detailing Demand Resources and ILR available, as requested by PJM;

Section 3 Entry of customer-specific Demand Resource and ILR credit information, for planning and verification purposes, into the designated PJM electronic system.

Section 4 Customer-specific compliance and verification information for each PJM-initiated Demand Resource or ILR event, as well as aggregated Provider load drop data for Provider-initiated events, in accordance with established reporting guidelines.

Section 5 Load drop estimates for all Demand Resource or ILR events, prepared in accordance with the PJM Manuals.

J. The Nominated Value of each Demand Resource or ILR shall be determined consistent with the process for determination of the capacity obligation for the customer.

The Nominated Value for a Firm Service Level customer will be based on the peak load contribution for the customer, as determined by the 5CP methodology utilized to determine other ICAP obligation values. The maximum Demand Resource or ILR load reduction value for a

Firm Service Level customer will be equal to Peak Load Contribution – Firm Contract Level adjusted for system losses.

The Nominated Value for a Guaranteed Load Drop customer will be the guaranteed load drop amount, adjusted for system losses, as established by the customer's contract with the Provider. The maximum credit nominated shall not exceed the customer's Peak Load Contribution.

The Nominated Value for a Direct Load Control program will be based on load research and customer subscription. The maximum value of the program is equal to the approved per-participant load reduction multiplied by the number of active participants, adjusted for system losses. The per-participant impact is to be estimated at long-term average local weather conditions at the time of the summer peak.

Customer-specific Demand Resource or ILR information (EDC account number, peak load, notification period, etc.) will be entered into the designated PJM electronic system to establish credit values. Additional data may be required, as defined in sections K and L.

K. Nominated Values shall be reviewed based on documentation of customer-specific data and Demand Resource or ILR information, to verify the amount of load management available, and to set a maximum allowable Nominated Value. Data is provided by both the zone EDC and the Provider on templates supplied by PJM, and must include the EDC meter number or other unique customer identifier, Peak Load Contribution (5CP), contract firm service level or guaranteed load drop values, applicable loss factor, zone/area location of the load drop, LSE contact information, number of active participants, etc. Such data must be uploaded and approved prior to the first day of the Delivery Year for such resource as a Demand Resource, or certification of such resource as ILR. Providers must provide this information concurrently to host EDCs.

For Firm Service Level and Guaranteed Load Drop customers, the 5CP values, for the zone and affected customers, will be adjusted to reflect an "unrestricted" peak for a zone, based on information provided by the Provider. Load drop levels shall be estimated in accordance with guidelines in the PJM Manuals.

For Direct Load Control programs, the Provider must provide information detailing the number of active participants in each program. Other information on approved DLC programs will be provided by PJM.

L. Compliance is the process utilized to review Provider performance during PJM-initiated Demand Resource and ILR events. Compliance will be established for each Provider on an event specific basis for the Provider's Demand Resources or ILR dispatched by the Office of the Interconnection during such event.PJM will establish and communicate reasonable deadlines for the timely submittal of event data to expedite compliance reviews. Compliance reviews will be completed as soon after the event as possible, with the expectation that reviews of a single event will be completed within two months of the end of the month in which the event took place. Providers are responsible for the submittal of compliance information to PJM for each PJM-initiated event during the compliance period.

Compliance for Direct Load Control programs will consider only the transmission of the control signal. Providers are required to report the time period (during the Demand Resource and ILR event) that the control signal was actually sent.

Compliance is checked on an individual customer basis for FSL, by comparing actual load during the event to the firm service level. Providers must submit actual customer load levels (for the event period) for the compliance report. Compliance for FSL will be based on:

> End use customer's current Delivery Year peak load contribution ("PLC") minus the metered load ("Load") multiplied by the loss factor ("LF"). The calculation is represented by:
>
> (PLC) - (Load *LF)

Compliance is checked on an individual customer basis for GLD, and will be based on:

(i) the lesser of (a) comparison load used to best represent what the load would have been if PJM did not declare a Load Management event or the CSP did not initiate a test as outlined in the PJM Manuals, minus the Load and then multiplied by the LF, or (b) the PLC minus the Load multiplied by the LF. A load reduction will only be recognized for capacity compliance if the Load multiplied by the LF is less than the PLC.

(iii) Providers must submit actual loads and comparison loads for all hours during the day of the Load Management event or the Load Management performance test, and for all hours during any other days as required by the Office of the Interconnection to calculate the load reduction. Comparison loads must be developed from the guidelines in the PJM Manuals, and note which method was employed.

Compliance is averaged over the full hours of a load management event, for each customer or DLC program dispatched by the Office of the Interconnection. Demand Resource or ILR resources may not reduce their load below zero (i.e., export energy into the system). No compliance credit will be given for an incremental load drop below zero. Compliance will be totaled over all FSL and GLD customers and DLC programs to determine a net compliance position for the event for each Provider by Zone, for all Demand Resources committed and ILR Certified by such Provider and dispatched by the Office of the Interconnection in the zone. Deficiencies shall be as further determined in accordance with section 11 of Schedule DD to the PJM Tariff.

M. Energy Efficiency Resources

1. An Energy Efficiency Resource is a project, including installation of more efficient devices or equipment or implementation of more efficient processes or systems, exceeding then-current building codes, appliance standards, or other relevant standards, designed to achieve a continuous (during peak periods as described herein) reduction in electric energy consumption at the End-Use Customer's retail site that is not reflected in the peak load forecast

prepared for the Delivery Year for which the Energy Efficiency Resource is proposed, and that is fully implemented at all times during such Delivery Year, without any requirement of notice, dispatch, or operator intervention.

2. An Energy Efficiency Resource may be offered as a Capacity Resource in the Base Residual or Incremental Auctions for any Delivery Year beginning on or after June 1, 2012. No later than 30 days prior to the auction in which the resource is to be offered, the Capacity Market Seller shall submit to the Office of the Interconnection a notice of intent to offer the resource into such auction and a measurement and verification plan. The notice of intent shall include all pertinent project design data, including but not limited to the peak-load contribution of affected customers, a full description of the equipment, device, system or process intended to achieve the load reduction, the load reduction pattern, the project location, the project development timeline, and any other relevant data. Such notice also shall state the seller's proposed Nominated Energy Efficiency Value, which shall be the expected average load reduction between the hour ending 15:00 EPT and the hour ending 18:00 EPT during all days from June 1 through August 31, inclusive, of such Delivery Year that is not a weekend or federal holiday. The measurement and verification plan shall describe the methods and procedures, consistent with the PJM Manuals, for determining the amount of the load reduction and confirming that such reduction is achieved. The Office of the Interconnection shall determine, upon review of such notice, the Nominated Energy Efficiency Value that may be offered in the Reliability Pricing Model Auction.

3. An Energy Efficiency Resource may be offered with a price offer or as Self-Supply. If an Energy Efficiency Resource clears the auction, it shall receive the applicable Capacity Resource Clearing Price, subject to section 5 below. A Capacity Market Seller offering an Energy Efficiency Resource must comply with all applicable credit requirements as set forth in Attachment Q to the PJM Tariff. The Unforced Capacity value of an Energy Efficiency Resource offered into an RPM Auction shall be the Nominated Energy Efficiency value times the DR Factor and the Forecast Pool Requirement.

4. An Energy Efficiency Resource that clears an auction for a Delivery Year may be offered in auctions for up to three additional consecutive Delivery Years, but shall not be assured of clearing in any such auction; provided, however, an Energy Efficiency Resource may not be offered for any Delivery Year in which any part of the peak season is beyond the expected life of the equipment, device, system, or process providing the expected load reduction; and provided further that a Capacity Market Seller that offers and clears an Energy Efficiency Resource in a BRA may elect a New Entry Price Adjustment on the same terms as set forth in section 5.14(c) of this Attachment DD.

5. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by no later than 30 days prior to each Auction an updated project status and measurement and verification plan subject to the criteria set forth in the PJM Manuals.

6. For every Energy Efficiency Resource clearing an RPM Auction for a Delivery Year, the Capacity Market Seller shall submit to the Office of the Interconnection, by

ORIGINAL

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September 29, 2006

1 of 4

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

Re: Settlement Agreement and Explanatory Statement of the Settling Parties Resolving All Issues in <u>PJM Interconnection L.L.C.</u>, Docket Nos. ER05-1410-000 and -001, and EL05-148-000 and -001

Dear Ms. Salas:

PJM Interconnection, L.L.C. ("PJM"), pursuant to Rule 602 of the Commission's Rules, submits for filing, on behalf of itself and the parties listed in the enclosed Settlement Agreement (collectively "Settling Parties"), an original and 14 copies of the settlement documents described below.

I. Description of the Filing

The Settlement Agreement filed herein resolves all issues regarding the implementation by PJM of a reliability pricing model ("RPM") to replace PJM's existing capacity obligation rules, without the need for an evidentiary hearing or further proceedings. Therefore, the Settling Parties respectfully request that the Commission approve the Settlement Agreement, including the enclosed revised sheets of the PJM Open Access Transmission Tariff ("PJM Tariff"), PJM Operating Agreement, and the enclosed new Reliability Assurance Agreement for the PJM Region ("RAA"), as set forth in Attachments A through F to the Settlement Agreement.

II. Documents Enclosed

The Settling Parties submit the following settlement materials:

1. Explanatory Statement, including appendices containing supplemental affidavits of Mr. Andrew L. Ott, Mr. Joseph E. Bowring, and Mr. Benjamin F. Hobbs, on behalf of PJM; Mr. Paul Williams, on behalf of the Portland Cement Association; and Mr. Robert Stoddard, on behalf of Mirant.

2. Settlement Agreement, including appendices containing revised sheets to the PJM Tariff, Operating Agreement and RAA;

3. Proposed Letter Order; and

4. Certificate of Service.

III. Comment Dates

Pursuant to Rule 602(f)(2), comments on the Settlement Agreement must be filed with the Secretary within 20 days of the filing of the settlement, i.e., on or before October 19, 2006, and reply comments must be filed with the Secretary within 30 days of such filing, i.e. on or before October 30, 2006.

IV. Request for Review and Waiver

The Settlement Agreement provides that the RPM construct shall replace PJM's current capacity construct beginning on June 1, 2007, which is the first day of the next annual Delivery Year under the new capacity rules. To permit this implementation date, PJM must conduct the Base Residual Auction for the 2007-2008 Delivery Year in April 2007; therefore, PJM and the market participants must begin to implement the necessary systems and business practice changes as soon as possible. To that end, the Settling Parties are asking the Commission to approve the Settlement Agreement by December 22, 2006. To the extent necessary, waiver of the Commission's notice requirements is requested.

V. Service and Request for Waiver of Posting Requirements

Pursuant to Rules 602(d) and 2010 (18 C.F.R. §§ 385.602(d) & 2010), PJM has served, either by paper or electronic service, the settlement documents listed in section II above, on all the parties listed on the official service list compiled by the Secretary in this proceeding, all PJM members, and all state commissions in the PJM Region.

With regard to service on the PJM members and the state commissions, PJM requests waiver of the posting requirements, so as to permit electronic service rather than paper service. Waiver of paper service is consistent with the Commission's decision to establish electronic service as the default method of service on service lists maintained by the Commission Secretary for Commission proceedings.[1] While Order No. 653 did not amend the posting requirements, application of its rules to tariff filings would be consistent with the Commission's "efforts to reduce the use of paper in compliance with the Government Paperwork Elimination Act."[2] Applying amended section 385.2010(f) to

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[1] See Electronic Notification of Commission Issuances, Order No. 653, 110 FERC ¶ 61,110 (2005).

[2] Id. at P 2, citing 44 U.S.C. § 3504.

this filing, PJM will post this filing today to the FERC filings section of its internet site, http://www.pjm.com/documents/ferc.html, and send an e-mail to all PJM members and all state utility regulatory commissions in the PJM Region[3] alerting them that this filing has been made by PJM today and is available by following such link. Within one business day, PJM will send a second e-mail to the same list, containing a link that takes the recipient directly to the filed document.[4]

Respectfully submitted,

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Encl.
cc: Service List

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3 PJM already maintains, updates, and regularly uses e-mail lists for all Members and affected commissions.

4 PJM anticipates that in unusual circumstances, it may not be possible to post the document to its website on the day of filing, or to distribute an active link to the document within one business day. Consistent with §385.2010(i)(3), if a link to the document does not become available within two business days after filing, PJM will arrange for immediate service by other means.

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Tab 1
Explanatory Statement
And
Attachments

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket Nos.	ER05-1410-000, -001
	)		EL05-148-000, -001

EXPLANATORY STATEMENT

PJM Interconnection, L.L.C. ("PJM"), on behalf of the Settling Parties in this proceeding,[1] submits this Explanatory Statement in support of the enclosed Settlement Agreement and Offer of Settlement ("Settlement Agreement").[2] The Settlement Agreement resolves all issues in Docket Nos. ER05-1410-000 and -001 and EL05-148-000 and -001. Therefore, the Settling Parties request that the Commission approve the Settlement Agreement, including the revised tariff sheets in Attachments A through F to the Settlement Agreement.

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1 The Settling Parties, comprising most of the active parties in this proceeding with a broad cross-section of load interests, generation owner interests, and state regulators, are listed on page 1 of the Settlement Agreement. In addition, many other parties to the proceeding committed at the September 25, 2006 vote on this Settlement Agreement that they would not oppose Commission approval of the Settlement Agreement without condition or modification. The parties that cast such a vote are: American Municipal Power – Ohio, District of Columbia Office of the People's Counsel, Delaware Public Service Commission, Duquesne Light Co., Easton Utilities, Illinois Municipal Electric Agency, Northern Illinois Municipal Power Agency, NRG Energy, Inc., Ohio Consumer's Counsel, Ohio Public Utilities Commission, Pennsylvania Department of Environmental Protection, Pennsylvania Public Utilities Commission, Public Power Association of New Jersey, Rockland Electric Company, Borough of Chambersburg, Direct Energy Services, LLC, and Strategic Energy LLC.

2 PJM coordinated preparation of this Explanatory Statement with the RPM Settlement Drafting Committee, but any characterization herein of the Settlement Agreement or these proceedings is solely that of PJM and should not be attributed to any other party. In the event of any conflict between this Explanatory Statement and the Settlement Agreement, the provisions of the Settlement Agreement govern.

I. BACKGROUND

On August 31, 2005, PJM filed under sections 205 and 206 of the Federal Power Act ("FPA") a proposal for a reliability pricing model ("RPM") to replace its existing capacity obligation rules ("August 31st Filing"). In the August 31st Filing, PJM asked the Commission to find that its existing capacity construct is unjust and unreasonable and that its RPM proposal was a just and reasonable replacement.[3]

On April 20, 2006, the Commission issued an Initial Order on RPM.[4] In its order, the Commission found that PJM's existing capacity construct is unjust and unreasonable.[5] In addition, the Commission made a number of findings as to various aspects of the RPM proposal.[6] In addition to these findings, the Commission instituted a paper hearing and scheduled a technical conference to address a number of issues for which the Commission sought additional information.[7]

Pursuant to the April 20 Order, on May 19, 2006, PJM filed a brief on the paper hearing issues. Parties to the proceeding filed comments on PJM's brief on June 2, 2006, and reply comments on June 16, 2006.[8] The technical conference required by the April

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3 *August 31st Filing* at 3.

4 *PJM Interconnection, L.L.C.*, 115 FERC ¶ P61, 079 (2006) ("April 20 Order").

5 *Id.* at P 1.

6 *Id.* at P 6.

7 *Id.* at P 173.

8 The complete record compiled in the paper hearing in this case is generally referred to herein as the "Paper Hearing."

20 Order was held on June 7-8, 2006. Comments on the technical conference were filed on June 22, 2006.[9]

On May 8, 2006, the American Forest and Paper Association ("AFPA") filed a motion to establish settlement judge proceedings, and requested that Administrative Law Judge Lawrence Brenner conduct those proceedings.[10] AFPA also requested that the Commission suspend the technical conference and paper hearing procedures established in the April 20 Order pending the outcome of the proposed settlement judge proceedings.[11] On May 17, 2006, the Commission issued an Order Granting Motion for Appointment of Settlement Judge and Denying Request to Suspend Scheduled Proceedings.[12] In that order, the Commission established settlement judge procedures, but denied AFPA's request to suspend the procedural schedule during the course of the settlement judge proceedings.[13] In addition, the Commission granted AFPA's request that the scope of the settlement discussions would not be limited to the issues that the Commission ordered to be the subject of the paper hearing and technical conference.[14]

Beginning on June 5, 2006, and continuing through the end of July, the parties to this proceeding engaged in lengthy and intense settlement discussions. As noted in the

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9 The complete record compiled in the technical conference in this case is generally referred to herein as the "Technical Conference."

10 A number of parties either supported or did not oppose the motion to establish settlement judge proceedings.

11 *See* AFPA Motion at 1.

12 115 FERC ¶ 61,186 (2006).

13 *Id.* at P 1.

14 *Id.* at P 5.

August 3, 2006 Report By Settlement Judge On Agreement In Principle issued in this proceeding, over 150 individuals representing more than 65 parties engaged in more than 25 days of settlement discussions with direct Settlement Judge involvement and with the assistance of Mr. Steven Shapiro of the Dispute Resolution Service, and numerous other meetings among the negotiating parties during the settlement period. On August 2, the parties voted on an agreement in principle embodied in a settlement term sheet. All of the parties to the Settlement Agreement (at section I at p. 4) either voted to support or not oppose the settlement term sheet.[15]

Throughout the months of August and September, the parties either supporting or not opposing settlement engaged in further negotiations to resolve the open issues and specifics necessary to reach final settlement on all issues in the term sheet. In addition, the parties drafted and finalized the Settlement Agreement, the accompanying PJM Tariff sheets, and necessary changes to the Reliability Assurance Agreement ("RAA"). Following substantial completion of those documents,[16] the parties met again on September 25, 2006 and voted on the Settlement Agreement. The Settling Parties consist

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15 Only six parties to the proceeding voted to oppose the settlement term sheet. They were Catoctin Power, LLC, Coral Power LLC, Maryland Office of the People's Counsel, New Jersey Board of Public Utilities, PPL Parties, and the PSEG Companies (as noted in the Settlement Agreement).

16 The RPM Settlement Drafting Committee, consisting of designated representatives of PJM, buyers, and sellers, made minor conforming, clarifying, or correcting changes to the Settlement Agreement and tariff/RAA sheets after the vote, to prepare those documents for filing.

of all parties that voted at that time to support the settlement. The parties listed in footnote 1 above voted not to oppose the settlement.[17]

In preparation for filing, the parties also prepared this Explanatory Statement and several supplemental affidavits in support of the settlement. Those supplemental affidavits, Attachments A through E to this Explanatory Statement, are submitted by Mr. Andrew L. Ott, Mr. Joseph E. Bowring, and Professor Benjamin F. Hobbs, on behalf of PJM; Mr. Paul R. Williams, on behalf of the Portland Cement Association; and Mr. Robert B. Stoddard, on behalf of Mirant.

II. DETAILED DESCRIPTION OF THE SETTLEMENT AGREEMENT

A. Use of August 31st Filing as Baseline

The settlement in this case takes as its starting point the amendments to the PJM Tariff, Operating Agreement, and Reliability Assurance Agreement included in the August 31st Filing, and makes numerous specified changes to those provisions. To eliminate uncertainty, the Settlement Agreement (at section V at P. 46) states that unless otherwise provided therein, the provisions in the August 31st Filing apply. This approach also is reflected in the implementing revisions to the PJM Tariff, Operating Agreement and RAA that are set forth in Attachments A through F to the Settlement Agreement and expressly incorporated as part of the Settlement Agreement. The changes made by the Settlement Agreement to the new RPM Tariff attachment[18] and the new RAA relative to

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17 Four additional parties voted at that time to oppose the settlement. Those parties are BP Energy, the Long Island Power Authority, J.P. Morgan Energy Ventures Corp. and Mittal Steel.

18 In the August 31st Filing, the attachment to the PJM Tariff that contained the RPM terms and conditions was designated as "Attachment Y." For this filing, that attachment has been redesignated as "Attachment DD." However, all (continued)

the August 31st Filing are shown in redline form in this settlement filing (all other Tariff and Operating Agreement changes are redlined against the current effective sheets). The Settlement Agreement (at section V) further states that, to the extent there is a conflict between any provisions of the Settlement Agreement and the attached tariff and agreement provisions, those tariff and agreement provisions shall govern.

B. Implementation Date

The Settlement Agreement (at section II.A) provides that the RPM construct, as described in the Settlement Agreement and tariff sheets, shall replace PJM's current capacity construct beginning on June 1, 2007, which is the first day of the next annual Delivery Year[19] under PJM's capacity rules. To permit this implementation date, PJM must conduct the Base Residual Auction for the 2007-2008 Delivery Year in April 2007; therefore, PJM and the market participants must begin to implement the necessary systems and business practice changes as soon as possible. To that end, the Settling Parties request that the Commission approve the Settlement Agreement by December 22, 2006.

(continued)

language of that attachment remains the same as in the August 31st Filing, except for the changes shown by the redlining in this filing. Similarly, the new consolidated RAA has been redesignated from Rate Schedule FERC No. 42 in the August 31st Filing to Rate Schedule FERC No. 44 in this filing, but the text has been changed only as shown by the redlined version in this filing. In accordance with the Settlement Agreement (at section II.P.9) the RAA also has been updated to reflect relevant amendments to the East RAA, West RAA, or South RAA that have become effective since August 31, 2005.

19 Capitalized terms used in this Explanatory Statement that are not otherwise defined herein have the meaning given in the PJM Tariff or Reliability Assurance Agreement.

C. Variable Resource Requirement Curve

Consistent with the April 20 Order, which endorsed in principle reliance on a downward-sloping demand curve to clear the capacity market,[20] the Settlement Agreement (at section II.B) provides that the RPM capacity auctions shall be cleared using a downward-sloping Variable Resource Requirement Curve ("VRR Curve"). The VRR Curve adopted by the Settlement Agreement ("Settlement Curve"), however, contains significant modifications to the VRR Curve proposed by PJM in the August 31st Filing, which shift the curve downward to correlate the varying capacity requirement levels with generally lower prices. Id.

Figure 1 below compares the Settlement Curve with the curve proposed in the August 31st Filing.[21] As can be seen, the Settlement Curve establishes a lower value for capacity at nearly all capacity levels. There is a crucial point of convergence: both curves value at the Net Cost of New Entry a cleared capacity level equal to the Installed Reserve Margin plus one percent. This important feature of the proposed curve in the August 31st Filing, which was discussed and supported at length in the Technical Conference, is preserved by the Settlement. The curves diverge in both directions from that point, with the Settlement Curve yielding progressively lower prices as either capacity surpluses or capacity shortages increase. The curves also share the same zero crossing point, with both dropping to the horizontal axis at a cleared capacity level equal

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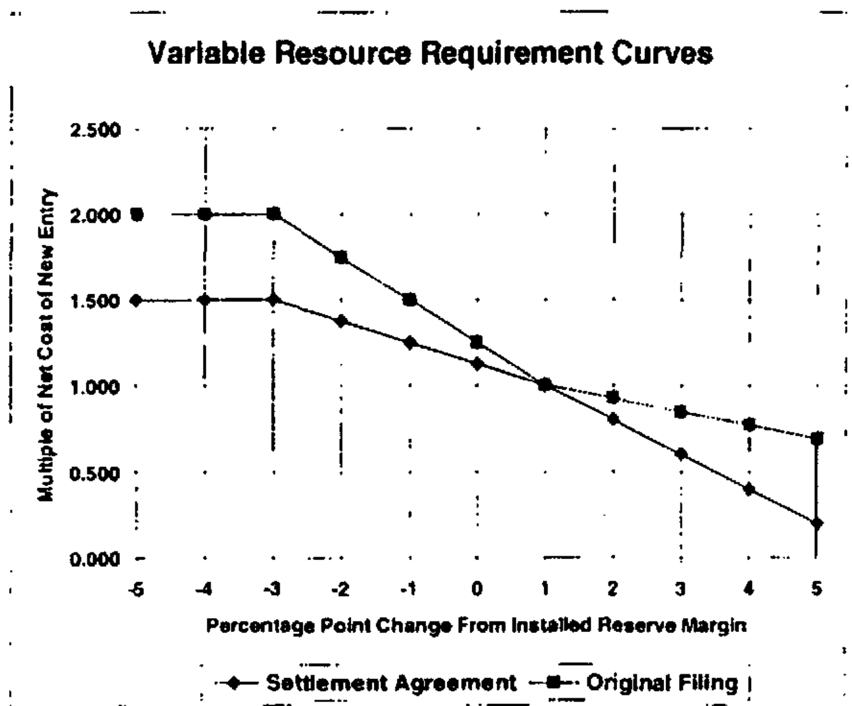
[20] April 20 Order at PP 104-108.

[21] The comparison illustrated here is not exact, due to a difference in the price calculation method. The VRR Curve included in the August 31st Filing calculated the price as [(multiplier) times (CONE)] minus (EAS Offset). The Settlement Curve calculates price as (multiplier) times [(CONE) minus (EAS Offset)].

to IRM plus five percent. By design, therefore, the Settlement Curve results in lower capacity costs at almost all capacity levels.

Figure 1
Comparison of Settlement Curve
and VRR Curve Proposed in the August 31st Filing



Even though it sets a lower capacity cost, the Settlement Curve performs similarly, on the key measures of long-term reliability and long-term total cost to consumers, to the VRR Curve proposed in the August 31st Filing. At PJM's request, Professor Benjamin F. Hobbs of the Johns Hopkins University supplemented his prior affidavits in this case to present the results of a long-run dynamic simulation of the relative performance of the Settlement Curve under a broad range of differing assumptions.[22] Based on his economic simulations, Professor Hobbs "conclude[s] that the Settlement Curve's performance would likely be similar to that of [the] [c]urve [that] was recommended by PJM in its August 31, 2005 filing, and much better than the vertical demand curve" that more closely reflects PJM's current capacity construct.[23]

As Professor Hobbs explains, his simulations show that the Settlement Curve is likely to lead to reserve levels meeting or exceeding the Installed Reserve Margin 95% of the time, compared with 98% of the time for the originally proposed curve.[24] Similarly, the Settlement Curve leads to comparable levels of total consumer costs as the originally proposed curve, i.e., $82/peak kW/year versus $79 peak kW/year.[25] Notably, the Settlement Curve performs far better on these measures than a "no demand curve" case that effectively is a vertical line at the Installed Reserve Margin, capped at a price of twice the CONE minus the energy and ancillary services revenue offset. The vertical demand curve is likely to meet or exceed the IRM only about 52 percent of the time, and leads to total consumer costs of about $123/peak kw/year, i.e., about fifty percent greater costs than either the Settlement Curve or the curve proposed in the August 31st Filing. Id. Thus, Professor Hobbs correctly observes that the differences between the Settlement Curve and PJM's originally proposed curve "are very small compared to the gulf between

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22 Discussion of Professor Hobbs' analysis in this filing does not imply endorsement of that analysis by any Settling Party.

23 Hobbs Supplemental Affidavit, at 8.

24 Id. at 5.

25 Professor Hobbs shoes that this relative performance of the Settlement Curve (i.e., comparable to, but slightly below the PJM-filed curve) continues across a wide range of sensitivity analyses, which reinforces his conclusions. Id. at 8.

their performance and that of Curve 1 ("No Demand Curve"), which performs much worse."[26]

In short, the differences between curve in the August 31st Filing and the Settlement Curve are minor compared to the substantial benefits of moving from the current construct to either of those two alternatives.

As stated by Mr. Andrew L. Ott in his supplemental affidavit, this analysis shows that the Settlement Curve provides reasonable assurance that the PJM Region will continue to meet reliability objectives.[27] His conclusion is amply supported by the record developed in the Technical Conference, which included extensive discussion of minimum acceptable reliability levels, alternative downward-sloping curves to meet these levels, and the details and relative merits of Professor Hobbs' simulation analysis and alternative analyses.

Moreover, while this detailed simulation modeling suggests that the Settlement Curve will help ensure continued reliability, the Settlement Agreement preserves PJM's ability to address any issues promptly if that expected reliability is not achieved. The Settling Parties have agreed to include the RPM terms and conditions in the PJM Tariff and Reliability Assurance Agreement, both of which are documents that PJM has the right to amend under FPA Section 205.[28] The Settlement Agreement (at section III) expressly adds that nothing in the agreement shall be construed as affecting in any way PJM's right unilaterally to make application to the Commission for a change in rates,

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26 Id. at 8.

27 Ott Supplemental Affidavit at 2.

28 Settlement Agreement at section III.

terms and conditions under FPA section 205.[29] The Settlement Agreement (at section III) leaves in place the originally-filed tariff provisions that require PJM to evaluate the need for changes to the VRR Curve or its parameters at least every three years,[30] to report on the performance of RPM within four and a half years after RPM is implemented,[31] and to investigate the costs and benefits of transmission upgrades in the RTEP process if elevated locational prices do not result in new entry.[32] Consistent with these provisions, even before three years have elapsed, if available evidence indicates that RPM is not working as intended to promote reliability, PJM will investigate the causes and exercise its FPA section 205 rights to file any necessary changes if warranted.

D. Forward Commitment of Capacity

The Settlement Agreement retains forward commitment of capacity largely as proposed in the August 31st Filing (and as endorsed in principle by the April 20th Order[33]), but reduces the forward period (i.e., the period between the Base Residual Auction and the start of the Delivery Year) when RPM is fully implemented from four years to three. As explained by Mr. Ott in his accompanying affidavit, three years remains sufficient to meet the essential purpose of forward commitment, i.e., to provide a

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29 By the same token, nothing in the Settlement Agreement is to be construed as restricting any rights of the other parties under the FPA, including their rights under section 206. In recognition of the careful balancing of positions, the Settlement Agreement requires PJM to hold at least one stakeholder meeting to discuss the proposed changes, and give at least 15 days prior notice of that meeting, before filing to change the Reference Resource or CONE Areas.

30 See PJM Tariff Attachment DD, section 5.10(a)(iii).

31 See PJM Tariff Attachment DD, section 17.6

32 See PJM Tariff Attachment DD, section 15.

33 April 20 Order at PP 67-72..

credible prospect of new entry. The unrebutted record supports this conclusion. PJM's witness Mr. Raymond L. Pasteris presented a detailed development timeline for a combustion turbine plant configuration typical of new entry units in the PJM Region. His timeline, which no party disputed, showed a typical 33-month period between the signing of an Incremental Facilities Study Agreement for a new plant and the plant's commercial operation date.[34] Under the RPM rules, a proposed new generation plant must have a signed Interconnection Facilities Study Agreement before it can participate in the Base Residual Auction,[35] which—pursuant to the Settlement Agreement—will take place 36 months before the start of the Delivery Year. Therefore, a three-year forward auction schedule still allows a typical new entry combustion turbine to offer into the auction and credibly commit to be in service by the Delivery Year.

The Settlement Agreement provides (at section II.C) that PJM will conduct a Base Residual Auction ("BRA") and three Incremental Auctions largely as proposed in Original Attachment Y, except for the one-year reduction in the forward schedule. The Base Residual Auction will be the basic mechanism to ensure the lowest cost, three-year forward commitment of capacity that satisfies the region's reliability needs and all locational constraints. Id. The three Incremental Auctions will provide a mechanism for market participants to commit additional resources that may be needed for the Delivery Year either to replace previously committed resources that have become unavailable or to accommodate an increase in the forecasted load (Id. at section II.D). Attachment F to this Explanatory Statement shows a timeline of all relevant milestones once RPM is fully

[34] See August 31st Filing, Tab I, p. 23, Figure 3.

[35] See RAA (Attachment A to the Settlement Agreement), section 1.67.

implemented, beginning with the first deadline for PJM to post information for auction participants, continuing through the Base Residual and Incremental Auctions, and culminating in the Delivery Year addressed by those auctions.

The Settlement Agreement provides that the commitment period for the capacity offered in the Base Residual Auction is one year, beginning on June 1 and continuing through May 31 of the following calendar year ("Delivery Year") (id. at section II.E). However, addressing concerns noted in the April 20 Order[36] and raised by both Commission Staff and intervenors in the Paper Hearing and Technical Conference, the Settlement Agreement also provides an opportunity under certain circumstances for new entry units to receive their first-year clearing price for up to two additional years, as further discussed in section II.J below.

F. Locational Requirements, System Constraints, and Integration of RPM with the RTEP Process

The Settlement Agreement (at section II.H) adopts locational capacity pricing largely as proposed in the August 31st Filing, retaining the connection—endorsed by the April 20 Order[37]—between the capacity pricing areas (known as Locational Deliverability Areas ("LDAs")) and the areas analyzed in the Regional Transmission Expansion Planning ("RTEP") process for system constraints. However, as explained below, the Settlement Agreement: (i) slightly lengthens the LDA phase-in schedule; (ii) requires an FPA section 205 filing before a new LDA is created; (iii) clarifies and makes more transparent the rules on when a separate VRR Curve is used in an LDA (which is a

36 April 20 Order at P 74.

37 Id. at PP 49, 52.

predicate to prices "separating," i.e., increasing in an LDA); and (iv) clarifies certain aspects of the interaction between RPM and the RTEP process id..

1. Phase-in of LDAs for RPM Pricing Purposes

This Settlement Agreement (at section II.H.1) retains, after a phase-in period, the 23 LDAs proposed in the August 31st Filing as potential capacity pricing regions. The record developed in the Paper Hearing fully supports and explains those 23 LDAs and their necessary relationship to the reliability planning process.

The Settlement Agreement (at section II.H.1) modifies the phase-in that precedes full implementation of those 23 LDAs. The August 31st Filing proposed two large LDAs for the expected first year of RPM, four large LDAs for the second year, and full implementation of the proposed 23 LDAs beginning with the third year id.. Under that proposal, the four LDAs proposed for the second year consisted of: Southwestern MAAC,[38] Eastern MAAC,[39] the MAAC Region plus APS,[40] and an LDA consisting of the remaining zones in the PJM Region (hereinafter, the "Rest of Market" or "ROM") (Settlement Agreement at section II.H.1).[41]

The Settlement Agreement establishes a phase-in of three years before full LDA implementation, rather than two, and uses the four LDAs described above for each of

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38 Potomac Electric Power Co. and Baltimore Gas & Electric Co.

39 Public Service Electric And Gas Co., Jersey Central Power & Light Co., Philadelphia Electric Co., Atlantic Electric, Delmarva Power & Light, and Rockland Electric.

40 SW MAAC and Eastern MAAC plus Pennsylvania Electric, Metropolitan Edison, PPL, and Allegheny Power.

41 Commonwealth Edison, American Electric Power, Dayton Power & Light, Dominion-Virginia Power, and Duquesne Light.

those three years. Accordingly, those four LDAs will be effective for the Delivery Years of 2007-08, 2008-09, and 2009-10. For the Delivery Year of 2010-11, all 23 LDAs will be effective. id.

The Settlement Agreement preserves, however, some of the potential price-signaling benefits of the full complement of 23 LDAs even during the transition. Id. After conducting the Base Residual Auctions for each of the first three Delivery Years, PJM will calculate and post, for informational purposes only, the prices that would have resulted if all 23 LDAs were in place. Potential project developers therefore will have additional information to help guide their project scope and location decisions, and market participants will have additional information to help prepare their hedging strategies and business practices for full RPM implementation.

2. Identification of Transmission Constraints for Pricing Purposes

The Settlement Agreement expressly recognizes that prices may not separate in all 23 LDAs (at section II.H.2). Indeed, prices cannot separate in an LDA unless the algorithm used to clear the auction employs a separate VRR Curve for that LDA, id., tailored to the capacity requirements for the expected peak loads in that LDA.[42] Notably, as the Settlement Agreement recognizes, even if an LDA has its own VRR Curve, the locational constraint may not bind and prices may not separate in that LDA, because the Base Residual Auction will clear using the actual resource offers in each of the LDAs.

[42] All such VRR Curves have the same shape and inflection points as the Settlement Curve described above; only the megawatt inputs (reflecting loads and demand resources only in the given LDA) and the dollar inputs (reflecting any subregional differences in the Net Cost of New Entry) will change. The algorithm used to clear the auction considers the PJM Region VRR Curve and any separate LDA VRR Curves through a simultaneous optimization calculation.

Taking account of these considerations, the Settlement Agreement improves upon the August 31st Filing by clearly establishing, and making transparent, the rules that determine when a separate VRR Curve will be used for an LDA (Settlement Agreement at II.H.2).

In particular, the Settlement Agreement establishes a default screen to determine whether to employ a separate VRR Curve for an LDA, based on objective measures that indicate that an LDA is constrained or is close to becoming constrained. Id. Accordingly, the Settlement Agreement provides that, consistent with the phase-in of LDAs discussed above, PJM will establish a separate VRR Curve for an LDA whenever the Capacity Emergency Transfer Limit ("CETL") for the LDA is less than 105% of the Capacity Emergency Transfer Objective ("CETO") for that LDA. Id. Moreover, even if this screen is not passed, PJM is permitted to determine that an acceptable level of reliability, consistent with the Reliability Principles and Standards (as defined in the RAA), requires establishment of a separate VRR Curve for an LDA with a margin greater than 5%. Id. The Settlement Agreement provides that, in such a case, PJM will post on its website, at least three months before the Base Residual Auction, the LDA for which the VRR Curve is being established and the margin or other information that is being used rather than the 5% margin. Id.

To ensure the market has other information that may influence prices and capacity commitments, the Settlement Agreement (section II.H.2) provides that PJM will post, at least three months before each Base Residual Auction, the CETO and CETL values for all LDAs; the LDAs that do not have the potential to bind because they are not constrained LDAs; the LDAs for which a separate VRR Curve has been established; and the separate curve and associated data (e.g., LDA Reliability Requirement, projected

Interruptible Load for Reliability, applicable Cost of New Entry, and applicable Net Cost of New Entry) for each such LDA.

3. Integration with Regional Transmission Expansion Planning Process

The Settlement Agreement (at II.H.3) clarifies the manner in which the Capacity Resources will be integrated with the Regional Transmission Expansion Planning process. First, Generation Capacity Resources that do not clear in the Base Residual Auctions, and are not sold elsewhere, shall be considered the minimum amount of at-risk generation in the market efficiency analysis of the RTEP process and shall be considered at-risk in the sensitivity cases in the RTEP market efficiency analysis. Id. The Settlement Agreement provides that, if necessary, PJM shall file to amend Schedule 6 of the PJM Operating Agreement to ensure such treatment of "at-risk" generation. Id. Second, the Settlement Agreement provides that the PJM planning market efficiency analysis shall take into account energy congestion and locational capacity prices, differentials in the initial cost-benefit determination of proposed transmission solutions, and later cost-benefit analyses. Id. PJM submitted tariff and Operating Agreement revisions to address reforms such as these in the RTEP process on Spetember 8, 2006 in Docket No. ER06-1474-000

4. Changes to LDAs

The Settlement Agreement adopts the offer made by PJM in its Paper Hearing reply comments that any LDA changes would require a section 205 filing (Settlement Agreement at section II.H.4.C). Specifically, the Settlement Agreement provides that, in order for PJM to change any of the LDAs, either during the transition or in the end state, PJM must make a filing under Section 205 of the FPA to effectuate such a change. Id.

The Settlement Agreement (at section II.H.4.a) further provides that, when a new LDA is included in the PJM RTEP planning process, PJM will make a filing to add such LDA to RPM (including a new aggregate LDA), so long as the new region is projected to have a CETL less than 105% of CETO, or if such new region is required to assure an acceptable level of reliability, consistent with the Reliability Principles and Standards, as discussed above.

In addition, market participants may propose, and PJM will evaluate, new LDAs (including new aggregate LDAs) for inclusion in the RTEP planning process and RPM under the standards described above.

F. Seasonal Pricing and Operational Reliability Requirements

The Settlement Agreement eliminates two features of the August 31st Filing—seasonal pricing and Operational Reliability Requirements—that added significantly to the complexity of RPM.

The April 20 Order questioned the justification for seasonal pricing and directed the parties to address the issue in the Paper Hearing.[43] While PJM reiterated its support for seasonal pricing, no intervenor that addressed the issue supported seasonal pricing. The Settling Parties have agreed, in the interests of compromise, to eliminate seasonal pricing.

The August 31st Filing also included rules to quantify the PJM Region's needs for generating capacity with certain attributes that enhance operational reliability, and to increase the auction clearing price as necessary to ensure commitment of units with such capabilities. The Settlement Agreement (at Section II.P.1) provides that these operational

[43] April 20 Order at P 74.

reliability requirements shall be eliminated from the capacity construct. However, the Settlement Agreement requires PJM to file with the Commission to implement by June 2008 markets and/or market rules, outside of the RPM markets, to address the "Operational Reliability Requirements" described in the August 31st Filing (i.e., load-following (which includes cycling) and thirty minute reserves). Id. The Settlement Agreement makes clear that PJM must make such a filing, through a stakeholder process or, if that fails, unilaterally, in time to implement this provision by June 2008. Id.

G. Determination of the Cost of New Entry

1. CONE for First Four Delivery Years

The Settlement Agreement (at section II.L.1)provides that the Cost of New Entry ("CONE") used to establish the VRR Curves for the Base Residual Auctions for the first, second, third, and fourth Delivery Years[44] shall be at the levels proposed in the August 31st Filing. The August 31st Filing and the record of the Technical Conference provide substantial evidence on which the Commission may approve this level of the Cost of New Entry for use during the initial years. The Settlement Agreement (at section II.L.1) provides that the CONE will be offset by the Net Energy and Ancillary Services Revenue offset, which will continue to be determined separately in accordance with the provisions of the Settlement Agreement (as discussed below) and the PJM Tariff.

2. Procedures for Possible Automatic Adjustment to the Cost of New Entry for the Fifth and Subsequent Delivery Years

The record of the Technical Conference also reflects substantial support for a mechanism that replaces a CONE value based on an administrative cost estimate (such as

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[44] That is, the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010. Id.

that proposed in the August 31st Filing) with a value that reflects empirical data on actual capacity market activity. The Settlement Agreement (at section II.L.2) establishes such an adjustment mechanism. As discussed below, and as more fully described in the accompanying affidavit of Mr. Paul R. Williams, the Settlement Agreement's carefully balanced "Empirical CONE" methodology (at section II at P 26) permits gradual changes (both up and down) in CONE to reflect auction-clearing prices in a given area. Professor Hobbs also reviews this aspect of the settlement and observes that this proposal will "move over time in the direction of the Empirical CONE if bidding behavior indicates a persistent shift in peaking technology costs," while "yield[ing] much less year-to-year variation than the situation where the demand curve's CONE was set equal to the Empirical Cone."[45]

As set forth in section 5.10(a)(iv)(B) of Attachment DD, the Cost of New Entry shall be subject to adjustment after the Transition Period when there is a Net Demand for New Resources in the auctions for a CONE Area over three consecutive Delivery Years. A Net Demand for New Resources means that, over the three-year period, the factors that increase demand for new entry, i.e., load growth and generation retirements, exceed the initial surplus of capacity in the first year of the three-year period, if any.[46] For this purpose, a surplus is defined as capacity in excess of the Installed Reserve Margin plus 1% (or the LDA equivalent of that regional IRM benchmark).

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45 Hobbs Supplemental Affdiavit at 9.

46 The net demand also can be increased or decreased to the extent the Capacity Emergency Transfer Limit for the area decreases or increases, respectively, over the three-year period.

When an area exhibits a Net Demand for New Resources over three years, its CONE may be adjusted depending on the level of capacity cleared in the Base Residual Auction for the third year.[47] If the amount of capacity cleared falls within a defined "Equilibrium Zone," no change to CONE is required. Generally speaking, the Equilibrium Zone is the area between capacity sufficient to meet the IRM and capacity sufficient to meet the IRM plus two percent (or the LDA equivalents of those measures). If capacity cleared is below the Equilibrium Zone, then CONE generally will be increased.[48] Conversely, if capacity cleared is above the Equilibrium Zone, CONE will be decreased, unless the quantity of capacity above the Equilibrium Zone stays constant or decreases over the three-year period.

When these provisions require an increase or decrease to the CONE in a CONE Area, the amount of the increase or decrease will be half the difference between the current CONE value and "Empirical CONE," but in either case the change can be no more than ten percent of the current CONE value. For this purpose, Empirical CONE is defined as the average of the clearing prices in the auctions for the CONE Area for the three years, plus the average of the Net Energy and Ancillary Services Revenue Offsets for that area over the three-year period.

This adjustment mechanism begins with the three large subregions of the PJM Region (known as "CONE Areas") for which separate administrative estimates of CONE

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47 In some circumstances, the trend in the quantity of capacity cleared over the three years is considered.

48 The exception is that if CONE was increased in the same area the previous year, it will be increased again only if there is a greater shortage below the Equilibrium Zone in the third year of the most recent three-year period than there was in the first year of that period.

were proposed in the August 31st Filing. When such CONE Areas encompass areas that are cleared with differing VRR Curves, the evaluation described above will be performed for each of those areas, and the results weight-averaged by the capacity obligation in each such area. Moreover, if an LDA has a separate VRR Curve for three consecutive years, then it will be evaluated on a stand-alone basis, and if the evaluation indicates a change in CONE of at least ten percent, then that area will become a "CONE Area," and its CONE will be adjusted by ten percent.

Notably, these limitations on automatic adjustments to CONE do not preclude PJM from exercising its FPA section 205 rights to file a change to the CONE value for any CONE Area.[49]

H. Net Energy and Ancillary Services Revenue Offset to the Cost of New Entry Used to Establish the VRR Curve

The Settlement Agreement (at section II.M) adopts a formulaic approach to determine the Net Energy and Ancillary Services Revenue Offset, largely as proposed in the August 31st Filing and previously supported in this proceeding,[50] with two notable changes. First, while the offset will be based (as proposed in the August 31st Filing) on the six most recent calendar years preceding the Base Residual Auctions for the first, second, and third Delivery Years,[51] only three years of history will be used for the

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49 As previously noted, PJM must hold at least one stakeholder meeting (with at least 15 days prior notice of such meeting) before filing at the Commission to change CONE.

50 See, e.g., Mr. Bowring's Affidavit in the August 31st Filing (at Tab G, pp. 1-9) and Mr. Ott's Technical Conference Affidavit, at pp.6-7.

51 Thus, the offset for the auctions conducted in 2007 for the Delivery Years beginning on June 1, 2007, June 1, 2008, and June 1, 2009 all will be based on LMPs and fuel costs over the period 2001 through 2006.

auctions for the subsequent Delivery Years.[52] Second, the offset shall be calculated on the assumption that the Reference Resource is dispatched on a "Peak-Hour" basis, rather than a "Perfect Dispatch" basis. As explained by Mr. Bowring and Mr. Ott in their prior affidavits in this proceeding,[53] perfect dispatch assumes the combustion turbine Reference Resource can respond perfectly to changes in LMPs, whereas peak-hour dispatch takes into account the operating limitations on starting, stopping, and re-starting such resources. Substantial evidence therefore supports use of the peak-hour dispatch approach in the Settlement Agreement (section II.M, page 28).

In addition to these changes, the Settlement Agreement (id. at page 27) also: (i) provides that the Reference Resource, and its heat rate, will be fixed in the PJM Tariff, changeable only through an FPA section 205 filing; (ii) further specifies the fuel cost assumptions in the calculation; and (iii) sets rules to calculate the offset in areas that have been integrated into the PJM Region for less than the otherwise applicable three or six calendar years.

I. Auction Clearing

The Settlement Agreement (at section II.G.2) clarifies Section 5.12 of Original Attachment Y to ensure that PJM minimizes total PJM Region capacity costs, regardless of whether the quantity clearing the Base Residual Auction is above or below the applicable target quantity, by providing that the optimization algorithm will select from

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52 Thus, the offset for the auction in May 2008 for the Delivery Year beginning June 1, 2011 will be based on LMPs and fuel costs for calendar years 2005, 2006, and 2007.

53 See note 50 above.

among multiple possible alternative clearing results that satisfy applicable constraints and requirements.

The Settlement Agreement lists (at section II.G.2), as examples of such alternatives, scenarios in which the auction clears by: (i) accepting a lower-priced Sell Offer that intersects the VRR Curve and that specifies a minimum capacity block; (ii) accepting a higher-priced Sell Offer that intersects the VRR Curve and that contains no minimum-block limitations; (iii) or rejecting both of the above alternatives and clearing the auction at the higher-priced point on the VRR Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the VRR Curve.[54] Attachment G to this Explanatory Statement provides graphs that illustrate these scenarios.

The Settlement Agreement (at section II.G.2) also fills a gap in RPM's auction-clearing rules by specifying how multiple Sell Offers that result in the same total cost will be cleared. This change, and the other changes noted above, provide greater clarity to the auction-clearing rules and greater certainty to market participants, than was provided by the August 31st Filing.

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54 The Settlement Agreement (at section II.G.2) also amends section 5.12 to add the basic principle that, when the supply curve falls short of the VRR Curve, the auction will clear at the point on the VRR Curve directly above the end of the supply curve. While Mr. Ott described this aspect of the clearing mechanism in his initial affidavit in this proceeding, see August 31st Filing, Tab E, at page 10, the rule was never explicitly stated in the tariff.

J. New Entry Price Adjustment

The April 20 Order posed the question whether a revenue commitment of more than one year was needed to induce new entry.[55] In its Paper Hearing Brief (at pages 36-37), PJM proposed a mechanism that would provide greater price certainty for up to five years for new units under certain circumstances. The Settlement Agreement (at section II.K) adopts a variant of that proposal as a "New Entry Price Adjustment" in the PJM Tariff, as described below and as more fully explained by Mr. Stoddard in his accompanying affidavit.

Under new section 5.14(c) of Attachment DD, a seller that offers a new entry unit that clears the Base Residual Auction for a Delivery Year may, by providing written notice with its offer in the first-year auction, elect to submit offers with a New Entry Price Adjustment in the Base Residual Auctions for the two immediately succeeding Delivery Years if: (i) acceptance of its offer in the first year moved the committed capacity in that LDA from a position below the LDA Reliability Requirement to a position well in excess of that requirement;[56] and (ii) the seller's offers in the two subsequent years are for a price equal to the lesser of its first-year offer price or 90 percent of the then-applicable Net CONE.

If these conditions are met, the seller's offer sets the clearing price (also received by all other sellers) in the first year and, if its offer clears in a subsequent year, it receives the higher of its first-year offer price or the clearing price for that subsequent year. Any

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55 April 20 Order at 74.

56 Specifically, any point on the downward-sloping curve where the price is at or below 40 percent of Net CONE.

payment to the seller above the clearing price will not increase the clearing price received by other sellers; rather, any such payment will be collected from all loads as a resource make-whole payment.

The Settlement Agreement (at section II.H.2) adds that so long as these conditions are satisfied, PJM shall continue to use a separate VRR Curve for the affected LDA, even if the LDA does not pass the 105% CETL-CETO test discussed above. Mr. Stoddard explains the reasons for this requirement in his Supplemental Affidavit (at page 5).

The Settlement Agreement further provides that the PJM Market Monitoring Unit's existing authority, review, and reporting responsibilities will include the New Entry Price Adjustment (at section II.K.2).

K. Minimum Offer Price Rule for New Entry in Constrained LDAs

The Settlement Agreement (at section II.J) adds a new Section 5.14(h) to Attachment DD of the PJM Tariff, establishing a Minimum Offer Price Rule for new entry sell offers in constrained LDAs. Mr. Stoddard discusses this rule in detail in his accompanying affidavit (at pages 6-11).

The new provision requires the PJM Market Monitoring Unit to develop locational asset-class estimates of competitive, cost-based, real levelized (year one) Cost of New Entry, net of energy and ancillary service revenues, consistent in most respects (except for the levelization) with the method used to determine the Cost of New Entry for initial use in RPM. The new section requires that these estimates of the Net Asset Class Cost of New Entry shall be zero for: (i) base load resources that require a period for development greater than three years; (ii) hydroelectric power production facilities; (iii) any upgrade or addition to an existing generation unt; or (iv) any new entry unit being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard.

The PJM Market Monitoring Unit will evaluate any offer based on a new entry unit submitted in a Base Residual Auction for the first Delivery Year in which the unit qualifies as new entry, in any constrained LDA, and determine whether (i) the offer affects the Clearing Price; (ii) the offer is less than 80 % of the applicable Net Asset Class Cost of New Entry;[57] and (iii) the seller and any affiliates have a "net short position" (as defined in section 5.14(h)(ii)(3)) in the Base Residual Auction for the LDA that equates to 5 or 10 percent (depending on LDA size) of the LDA Reliability Requirement.

If the PJM Market Monitoring Unit determines that these conditions are met, it will notify the seller and give it an opportunity to provide information to support its offer. If the seller doesn't provide the information, or the information doesn't support its offer, then an alternative Sell Offer, equal to 90% of the applicable Net Asset Class Cost of New Entry,[58] will be employed in place of the actual Sell Offer.

The Market Monitoring Unit then shall request that PJM perform a sensitivity analysis that re-calculates the clearing price for the Base Residual Auction employing the alternative sell offer, as described above, in place of the actual offer. If the new clearing

[57] If there is no applicable Net Asset Class Cost of New Entry, the test will be whether the offer is less than 70 percent of the Net Asset Class Cost of New Entry for the Reference Resource effective in such LDA.

[58] If there is no applicable Net Asset Class Cost of New Entry, then the offer shall be set equal to 80 percent of the Net Asset Class Cost of New Entry for the Reference Resource.

price and the initial clearing price differ by more than 25 dollars per megawatt-day (or if greater, by more than certain percentage amounts that vary based on the size of the LDA), then PJM shall redetermine the auction results by first calculating the replacement clearing price and the total capacity needed for the LDA, based on the alternative sell offer described above; and then accepting sell offers to fill that needed capacity, based on the actual offer prices and the following priority: (i) first, all Sell Offers in their entirety designated as self-supply; (ii) then, all Sell Offers of zero, prorating to the extent necessary, and (iii) then all remaining Sell Offers in order of the lowest price.

The Settlement Agreement (at section II.J.6) also states that this provision will terminate when there exists a positive Net Demand for New Resources (that is, when accumulated load growth and generation retirements overtake an initial capacity surplus), calculated cumulatively over all preceding RPM Delivery Years beginning with the first Delivery Year, for the portion of the PJM Region that was unconstrained during that first RPM Delivery Year. Even if this condition is met however, the Minimum Offer Price Rule will be reinstated for any constrained LDA that has a gross Cost of New Entry equal to or greater than 150 percent of the greatest prevailing gross Cost of New Entry in any adjacent LDA.

The Settlement Agreement (section II.J, pages 21-22) also emphasizes that this provision is not intended to reflect any position of the Settling Parties regarding the appropriate level of offer price for new capacity resources in a residual auction.

L. Transfer of Obligation to Pay Locational Reliability Charges

The Settlement Agreement (at section II.H.5) leaves in place provisions of the August 31st Filing that PJM will support self-supply and bilateral contracts through various means, including capacity pricing hubs and electronic forums for bilateral transactions. The Settlement Agreement adds to those options a new mechanism for Load-Serving Entities to transfer to one another or to other market participants (for purposes of PJM settlements and billing) their obligations to pay Locational Reliability Charges. The Settlement Agreement provides that PJM shall facilitate a process, similar to its current bilateral energy trading tool, eSchedules, whereby before or after any Base Residual Auction, an LSE or other Market Participant can provide PJM with a schedule that specifies the transferor, transferee, volume of capacity to be transferred, location where capacity prices are calculated, and start and end date of that transfer. The Settlement Agreement clarifies that such transfers shall not alter the physical supply and demand balance in the BRA, nor establish any obligations that are incompatible with any RPM auction.

M. Market Power Mitigation

The Settlement Agreement (at section II.I) provides that all market power mitigation rules shall be as proposed in the August 31st Filing and in PJM's May 19, 2006 Brief on Paper Hearing Issues (at pages 25 to 38).[59] with certain exceptions, as discussed below.

59 Certain of the redlined changes to section 6 of Attachment DD implement PJM's commitment in the Paper Hearing Brief that the outcome of the Commission's consideration of the "three pivotal supplier" test in the energy market would be applied to the RPM market power mitigation rules. *See, e.g.*, sections 6.3(b)(ii) and 6.3(c).

1. Market Power Mitigation Rules for Planned Generation Capacity Resources

The August 31st Filing provided that offer caps would not be applied to sell offers relying on Planned Generation Capacity Resources,[60] and that such resources remained "planned" until their commercial operation date, allowing them to offer into as many as four Base Residual Auctions without offer capping. The Settlement Agreement (at section II.I.1) amends Section 6.5(a)(ii) of Attachment DD to provide that offers based on Planned Generation Capacity Resources are not subject to offer capping in the auctions for the first Delivery Year that the resource qualifies as a planned resource, but may be rejected if found by the PJM Market Monitoring Unit not to be competitive in accordance with certain specified criteria and procedures.

The Settlement Agreement (Id. at page 12) elaborates that new entry offers for a planned resource's first year generally will not be rejected if: (1) collectively all new entry offers provide capacity of at least twice the incremental quantity of new entry needed to meet the LDA Reliability Requirement (i.e., the LDA's equivalent of IRM + 1); and (2) at least two unaffiliated suppliers have submitted new entry offers in the LDA. Even if those conditions are met, however, a seller, together with its Affiliates, whose new entry offers in that LDA are pivotal, is subject to mitigation.

Where the first two conditions are not met, or the seller and its Affiliates' new entry offers are pivotal, the Market Monitoring Unit will conduct further analysis to determine whether to reject the new entry offer as not consistent with competitive conditions. The MMU will compare such offers against other new entry offers and with

60 See August 31st Filing, Tab C (Attachment Y), Section 6.5(a)(ii).

various measures of the Net Cost of New Entry, both in that LDA and other LDAs (with due recognition for locational differences). The MMU also will evaluate potential barriers to new entry on the basis of interviews with potential suppliers and other market participants. If the Market Monitoring Unit determines based on these analyses to reject the offer as non-competitive, it will notify the seller after the auction, but before the final determination of clearing prices and offer it an opportunity to submit a revised offer. If the revised offer is found competitive by the MMU in accordance with the above criteria, PJM will clear the auction with the revised offer in place. If the revised Sell Offer is not deemed competitive, it will be rejected.

After it clears for one year, a new unit is treated as existing (and potentially subject to offer capping) in the auctions for subsequent years. However, as described above in section II.J, such resources may receive certain price assurances for the two Delivery Years that follow their first Delivery Year of service, under the New Entry Price Adjustment.

2. Modifications and Clarifications to Avoidable Cost Formula

The Settlement Agreement (at section II.I.2) also modifies the Avoidable Cost Rate (i.e., the offer-capping rate) and associated rules contained in Section 6.8 of Original Attachment Y in several respects.

First, the Settlement Agreement amends the definition of "Project Investment" in section 6.8(a), and the related rule in section 6.8(d) defining avoidable cost, to clarify that expenditures reasonably required to improve a unit's availability during Peak-Hour Periods can be recovered under the avoidable cost cap.

Second, the Settlement Agreement modifies the Capital Recovery Factor tables in section 6.8(a) by adding two new categories that allow more rapid recovery of Project

Investment under certain conditions. The first new category, known as "Mandatory Capital Expenditures," with an assumed recovery period of four years, is available to certain types of units that must make a Project Investment to comply with a governmental requirement that otherwise would materially impact operating levels in the Delivery Year. Coal, oil, or gas-fired units that are at least 15 years old can elect this recovery option under certain specified conditions; and coal-fired units that are at least 50 years old can elect this option under certain other conditions. No offer electing this option can exceed a level of 90% of the then applicable Net Cost of New Entry.

The second new category, known as the "40-Year Plus Alternative" allows recovery of all Project Investment in only one year. This alternative is available to gas or oil-fired resources that are at least 40 years old, unless the resource is receiving generation deactivation credits under PJM's Tariff. No offer electing this option can exceed the then applicable Net Cost of New Entry, and if a seller elects this highly accelerated one-year recovery option, its unit will be treated as "at-risk" in PJM's transmission planning sensitivity analyses.

Third, the Settlement Agreement (id., at page 13) establishes certain additional general rules and procedures on recovery of capital expenditures. Sellers may elect the highest Capital Recovery Factor for which they are eligible, or the next highest CRF. If a seller elects the "16-Plus" CRF (based on recovery of costs over five years) for the Base Residual Auctions for the 2007-2008 or 2008-2009 Delivery Years, its offer cannot exceed the then-current Net Cost of New Entry. In addition, a seller relying on any CRF must provide the PJM Market Monitoring Unit with detailed information in support of its proposed capital recovery, including, for informational purposes only, evidence of the actual expenditure of the Project Investment when that information becomes available. If a seller submits an offer relying on the CRF table, but the project associated with its Project Investment is not in commercial operation during the relevant Delivery Year, it must either (i) make a rebate payment; (ii) hold the rebate payment in escrow if the project will be in operation the next year; or (iii) make a reasonable investment in the amount of the Project Investment in other existing generation units owned or controlled by it or its Affiliates in the same LDA.

3. Relaxed Information Requirement Conditions

The August 31st Filing proposed that sellers in areas that failed a preliminary market structure screen would be required to submit extensive cost data and supporting material in advance of the Base Residual Auction so that the PJM Market Monitoring Unit could calculate an offer cap for that seller in case the auction results indicated that offer capping was required. The Settlement Agreement (at section II.I.3) establishes categories of prospective sell offers for which this information will not be required.

In particular, if a sell offer concerns a unit that is in an unconstrained area of the PJM Region (*i.e.*, an area without a separate VRR Curve) and the unit is in a class that is not likely to include the marginal price-setting resources in such auction, then the offer-capping information need not be submitted. Alternatively, even if the above conditions are not met, but the seller commits that its offer will not exceed a price above the level identified for the relevant resource class by the Market Monitoring Unit, then it need not submit the offer-capping information.

The Settlement Agreement (at section II.I.3 at page 17) provides that the PJM Market Monitoring Unit shall determine, in its discretion, following stakeholder consultation, the resource classes and corresponding prices described above, and shall post such resource classes and prices three months before the Base Residual Auction.

The Settlement Agreement clarifies that these rules do not preclude the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit; and that compliance with such a request shall be a condition of participation in any auction. The Settlement Agreement also establishes rules for rejection and resubmission of offers that are inconsistent with any commitment made by a seller to qualify for the relaxed information requirement.

The Settlement Agreement (at section II.I.2, page16) also modifies Section 6.7 of Attachment DD to provide that when a seller submits the offer-capping cost data and supporting material, the Market Monitoring Unit shall notify the seller one month before the auction whether the submittal will be accepted, and if not, provide the seller detailed information as to why the submittal was not accepted.

4. Offer Cap Offset

When an offer is subject to offer-capping, the cap is reduced by the amount of certain other revenues the unit is projected to receive during the Delivery Year in question. The August 31st Filing generally provided that these Projected PJM Market Revenues would be based on the same method used to determine the net revenue offset for the Variable Resource Requirement Curve. The extent of reliance on that method, however, which concerned an estimate for a hypothetical Reference Resource, was not clear as applied to the projected revenues of the specific units that would be subject to offer-capping.

The Settlement Agreement (at section II.I.4) clarifies this matter by providing in a new section 6.8(d) that a generating unit's Projected PJM Market Revenues shall include all actual unit-specific revenues over certain specified time periods from PJM energy markets, PJM ancillary services, and unit-specific bilateral contracts from such unit, net of marginal costs for providing such energy[61] and ancillary services from such resource.

The historic time periods used for this purpose are the same as those used to compute the offset for the VRR Curve: for the Base Residual Auctions held in 2007 for the first three RPM Delivery Years (2007-08, 2008-09, 2009-10), a unit's Projected PJM Market Revenues will be the simple average of its net revenues (as described above) for calendar years 2001-2006; and for Delivery Year 2010-11 and thereafter, a unit's Projected PJM Market Revenues will be the rolling simple average of such net revenues from the three most recent calendar years before the BRA is held.

The Settlement Agreement also establishes rules to govern this calculation for units that were not in commercial operation, or were in areas not integrated into the PJM Region, for part of the three or six calendar year periods considered.

5. Market Power Mitigation During the Transition Period

The Settlement Agreement (at section II.I.5) amends the Transition Period rules in section 17 of Attachment DD to make clear that the market power mitigation rules in section 6 of that attachment apply to all RPM auctions conducted for the Transition Period. However, the Settlement Agreement also establishes one special rule effective only during RPM's first three Delivery Years. If a signatory to the Settlement Agreement (id. at P. 18), or any Affiliate of such a signatory, that owns or controls less than 10,000 megawatts of capacity in the PJM Region,[62] submits an offer in an auction for any of the

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[61] That is, costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the PJM Operating Agreement.

[62] This ceiling applies separately to a seller's merchant and regulated fleets.

first three RPM years, its offer is in an unconstrained part of the PJM Region (i.e., the area has no separate VRR Curve), and its offer is subject to offer capping, then the offer cap for up to 3000 megawatts of the seller's offered Unforced Capacity will be increased by up to $10/MW-day for the 2007-2008 or 2008-2009 Delivery Years and up to $7.50/MW-day for the 2009-2010 Delivery Year

N. Peak-Hour Period Availability Charges and Credits

The Settlement Agreement (at section II.N.2) significantly enhances the capacity construct in the PJM Region by adding a means to assess whether generation resources committed as capacity actually are available at expected levels during peak periods, and by crediting or charging resources to the extent they exceed or fall short of that expected availability. As explained by Mr. Ott in his accompanying affidavit (at pages 3-4), this will provide generation owners a significant added incentive to ensure that their capacity resources are available when they are most needed, and provide loads greater assurance that their payments for capacity will help maintain peak-period reliability. This balanced, negotiated provision also protects sellers, by limiting their maximum exposure to these charges, and by establishing special rules for units that run very few hours during the year and natural-gas-fired units that encounter winter-period supply disruptions.

As described below, the Settlement Agreement (at section II.N.2) adds a new section 10 to the RPM attachment in the PJM Tariff, addressing peak-hour period availability charges and credits. For each seller, its units' actual availability during Peak-Hour Periods[63] will be compared against their expected availability, and the seller will be

[63] Peak-Hour Periods are defined as the hours between 2:00 p.m. and 7:00 p.m. on non-holiday weekdays in the summer (June through August) and the hours between (continued)

charged, or credited, to the extent its portfolio of units in an LDA has a net availability shortfall, or net availability excess, respectively.[64]

A unit's expected availability will be based on its demand-equivalent forced outage rate ("$EFOR_D$") for the entire year, using the rolling average $EFOR_D$ for the five most recent annual $EFOR_D$ testing periods.[65] The Settlement Agreement (at section II.N.2) provides that those calculations will exclude outages deemed outside plant management control ("OMC") in accordance with NERC standards and guidelines.

A unit's actual peak-hour period availability for a Delivery Year will be calculated during the Peak-Hour Periods of that Delivery Year, considering only the unit's forced outage hours during those periods when the unit would have been called upon, i.e., the outage hours during which the unit's cost-based energy offer would have been less than the applicable LMP, or when the unit would have been called upon (absent the outage) for operating reserves.[66] The calculation will exclude OMC outages, and will not include any capacity unavailability that resulted in a charge or penalty under other PJM provisions due to delay, cancellation, retirement, de-rating, or rating test failure.

If a unit has fewer than fifty total service hours during Peak-Hour Periods, then its actual peak-hour period availability will be based on the unit's $EFOR_D$ (calculated in the

(continued)

7:00 a.m and 9:00 a.m. and between 6:00 p.m. and 8:00 p.m. on non-holiday weekdays in the winter (December through January).

64 These charges and credits do not apply to wind or solar resources.

65 PJM's $EFOR_D$ calculations are based on 12-month periods ending September 30.

66 In both cases, PJM will determine whether a unit would have been called on consistent with the PJM Manuals (including, without limitation, respecting such unit's operating constraints).

same manner as for the Unforced Capacity it is allowed to sell, i.e., using the most recent twelve-month $EFOR_d$ period, rather than the average of five such periods). The Settlement Agreement (at pages 32-33) adds that if a single-fueled, natural gas-fired unit fails to perform during the winter Peak-Hour Period, it will be excused if the owner can demonstrate to PJM that the failure was due to non-availability of gas to supply the unit.

In addition to getting the benefit of portfolio netting, a seller that expects its unit to experience a Peak-Hour Period outage that could result in an availability shortfall (or whose unit is actually experiencing such an outage) may obtain and commit replacement capacity (not previously committed) meeting the same locational requirement, as a way of avoiding or mitigating the shortfall.[67]

The Settlement Agreement (at section II.N.2, page 32) also bounds a seller's exposure by providing that, in most cases, the maximum shortfall for any of its units cannot exceed 50% of the unit's Unforced Capacity. The exception is that if a unit's availability is so poor that it triggers the 50% limit, then its maximum shortfall for the next year is raised to 75% of the unit's Unforced Capacity. If the unit then hits that 75% level, there is no limit on the potential reduction to its Unforced Capacity in the following year. When the percentage exposure is increased for a unit, it remains at that level until the unit's shortfall, if any, falls below 50% of its Unforced Capacity for three consecutive years.

Any seller with a net availability shortfall in an LDA as determined under these rules will be assessed a Peak-Hour Period Availability Charge, equal to such shortfall

[67] The settlement contemplates that replacement capacity will be committed through PJM's eCapacity system, which allows such commitments to take effect on one day's notice.

times the annual clearing price for that LDA for the Delivery Year in question, i.e., 365 times the clearing price expressed in $/MW-day. The revenues from such charges shall be distributed first to RPM auction sellers and FRR Entities that have a net excess in peak-hour period availability for their committed capacity in that LDA.[68] Any revenues remaining after that distribution will be distributed to all LSEs in the Zone that were charged the same Locational Reliability Charge for the Delivery Year for which the Peak Hour Period Availability Charge was assessed, and to all FRR Entities in the Zone that are LSEs and whose FRR Capacity Plan resources over-performed in the Delivery Year, on a pro-rata basis in accordance with each LSE's Daily Unforced Capacity Obligation.[69]

As described above, new section 10 provides that a single-fueled, natural gas-fired unit's failure to perform during the winter peak period will be excused if the seller can demonstrate to PJM that such failure was due to non-availability of gas to supply the unit. The Settlement Agreement (at P. 32) adds that, by June 1, 2007, PJM will analyze the historical availability of gas supplies in the PJM Region during winter conditions and its impact on the ability of generators to deliver capacity and to otherwise affect their reliability of performance. PJM shall, to the extent that such analysis indicates is necessary, develop adequate performance metrics within the PJM Manuals, and file to change the above provision of section 10 through an FPA section 205 filing.

68 The maximum credit is based on the seller's net availability excess times the applicable clearing price.

69 The Settlement Agreement (at section II.N.2) also provides that PJM will provide estimated charges and credits under new section 10 for the summer Peak-Hour Periods by three months after the end of that summer period, with final charges and credits billed by three calendar months after the end of the winter period.

O. Ability to Cure Rating Test Failure Charge

The Settlement Agreement (at section II.N.1) mostly leaves in place the various resource performance charges and credits proposed in Sections 7-13 of Original Attachment Y.[70] Generally speaking, sellers that commit a resource that becomes unavailable (or derated) before the Delivery Year have an opportunity to procure replacement capacity through either the first or third incremental auctions (conducted 23 months and 4 months before the Delivery Year, respectively) and thereby avoid or mitigate performance or deficiency charges they might otherwise incur.

The Settlement Agreement (at section II.N.1) provides a similar ability to avoid or mitigate charges resulting from a rating test failure that occurs during the Delivery Year. Consistent with the practice under PJM's current capacity construct, a generation resource will be tested under Attachment DD, section 7 in both the summer and winter to verify its rated installed capacity. If it fails the test (multiple testing is allowed), then the resource can be assessed a performance charge retroactively to the start of the relevant season. The Settlement Agreement (id.) modifies that section to provide that a seller that fails (or is expected to fail) a rating test may obtain and commit capacity from a replacement unit meeting the same locational requirements (including uncommitted or uncleared capacity from units that were otherwise committed).[71]

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70 The Operational Reliability Performance Charge formerly provided in section 10, however, has been replaced by the Peak-Hour Period Availability provision discussed above.

71 As with the designation of replacement capacity under the peak-period availability provision discussed above, commitments of replacement capacity will be effective upon no less than one day's notice to PJM.

P. Reliability Backstop

The Settlement Agreement (at section II.F) retains Section 16 of Original Attachment Y, but modifies section 16.3(a)(i) to provide that, rather than being triggered after four consecutive years, the Reliability Backstop will be triggered "if the total Unforced Capacity of all Capacity Resources committed through Self-Supply or the Base Residual Auctions for three consecutive Delivery Years." (emphasis added).

Q. Fixed Resource Requirement

PJM included in its August 31st Filing the outlines of an alternative means of addressing capacity obligations, outside the RPM capacity auctions, through a long-term commitment of resources.[72] In the April 20 Order, the Commission endorsed such an alternative and found that LSEs choosing this option must do so for an extended period of time, and must not be allowed to move in and out of the forward procurement auction from year to year.[73]

The Settlement Agreement (at section II.O.2) adopts a long-term Fixed Resource Requirement Alternative ("FRR Alternative") based on that outlined by PJM in the August 31st Filing, with various changes. The Settlement Agreement clarifies that the FRR Alternative applies only to the ability of an FRR Entity to meet its capacity obligations and does not affect the ability of an FRR Entity to participate in any other PJM markets. Id.

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72 August 31st Filing at Tab [A].

73 April 20 Order at PP 110-111.

1. Eligibility

An investor-owned utility ("IOU"), Electric Cooperative, or Public Power Entity, as defined in the RAA, shall be eligible to select the FRR Alternative if it demonstrates the capability to satisfy the entire Unforced Capacity obligation for all load, including load growth, in the applicable FRR Service Area for the term of such entity's participation in the FRR Alternative. (Settlement Agreement at section II.O.1).

Eligible entities that select the FRR Alternative must designate all load, including load growth, in the PJM Region. However, an FRR Entity may split its loads between RPM and the FRR Alternative if: (1) the Party elects the FRR Alternative for all load (including expected load growth) in one or more FRR Service Areas; (2) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (3) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals.[74]

In addition, an LSE that serves only its affiliates ("Single-Customer LSE") may select the FRR Alternative, provided that: (a) the Single-Customer LSE is a signatory to this Settlement Agreement (or is an entity that (i) is a named member of an association or coalition that is a signatory to the Settlement Agreement, and (ii) does not file or join in any comments opposing this Settlement Agreement); (b) the Single-Customer LSE selects the FRR Alternative on or before April 1, 2008; (c) the Single-Customer LSE

[74] The Settlement Agreement (at section II.O.1, pages 33-34) provides that PJM will use sub-accounts for parties meeting these conditions, to facilitate implementation of these provisions.

meets the requirements of Section B.3. of Schedule 8.1 to the PJM RAA; and (d) the aggregate total of such selections does not exceed 1000 MW of Obligation Peak Load in the PJM Region. Settlement Agreement at Section II.O.1, page 34.

2. Election, and Termination of Election, of the FRR Alternative

An entity eligible for the FRR Alternative must make its initial selection of the FRR Alternative option no less than two months before the conduct of the BRA for the first Delivery Year for which such election is to be effective (Settlement Agreement at Section II.O.2). Such notice must be provided in writing to the Office of the Interconnection and the minimum duration of the FRR Alternative selection is five consecutive Delivery Years.

An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to PJM no later than two months prior to the BRA for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

However, in the event of a State Regulatory Structural Change, as defined in Section 1.68 of the RAA, the affected FRR Entity may either elect the FRR Alternative or terminate its election of the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to PJM as soon as possible but in any event no later than two months prior to the BRA for such Delivery Year. Id. at page 35.

No later than one month prior to the deadline for entities to select the FRR Alternative, PJM shall post on its website the percentage of Capacity Resources required to be located in each LDA. Id.

3. FRR Capacity Plan and FRR Commitment Insufficiency Charge

No later than one month before the initial BRA after FRR selection, each FRR Entity shall submit its FRR Capacity Plan to PJM demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet the FRR Entity's Daily Unforced Capacity Obligation for the load identified in the FRR Capacity Plan. Each FRR Entity shall extend and update such plan by no later than one month prior to the BRA for each succeeding Delivery Year. Id. at page 35.

Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each planned Generation or Demand Response resource, the planned deactivation or retirement of any such resource, and the status of commitments for each sale or purchase of capacity included in the FRR Capacity Plan. Id.

The FRR Capacity Plan of any FRR Entity that commits, for any Delivery Year, not to sell surplus Capacity Resources as a Capacity Market Seller in the RPM auctions, either directly or indirectly, shall designate Capacity Resources in an amount 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. Id. at page 36. Those FRR Entities that do not commit, for any Delivery Year, to not sell surplus Capacity Resources as a Capacity Market Seller in the RPM auctions, either directly or indirectly, shall designate Capacity Resources at least equal to the Threshold

Quantity, as defined in Section 1.68A and Schedule 8.1 to the PJM RAA. The Threshold Quantity cannot be sold into the RPM auctions, but can be used to meet the FRR Entity's load growth or be sold to an entity outside of PJM or to another FRR Entity. Id.

All Capacity Resources committed in an FRR Capacity Plan shall meet the applicable Capacity Resource requirements pursuant to the RAA and the PJM Operating Agreement and must be on a unit-specific basis. Capacity Resources that are subject to bilateral contract(s) for less than a full Delivery Year may be committed in an FRR Capacity Plan if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years. Id.

All load management programs on which an FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan and satisfy all requirements applicable to Demand Resources. However, previously uncommitted Unforced Capacity from such load management programs may be used to satisfy an increased capacity obligation of an FRR Entity. Id.

For each LDA for which PJM establishes a separate VRR Curve for any Delivery Year addressed by a Capacity Resource Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA ("Percentage Internal Resources Required"). Such Percentage Internal Resources Required shall be calculated as provided in Section D.5. of Schedule 8.1 to the PJM RAA. An FRR Entity may reduce its Percentage Internal Resources Required for an LDA by committing to a Qualified Transmission Upgrade, as set forth in Attachment Y to the PJM Tariff, that increases the CETL for such LDA. Id. at page 37.

PJM shall assess the adequacy of all FRR Capacity Plans. If PJM determines that an FRR Capacity Plan submitted by an entity seeking to elect the FRR Alternative does not satisfy the Party's capacity obligations, the entity shall not be permitted to elect the FRR Alternative. Id.

If a previously approved FRR Entity submits an FRR Capacity Plan that is not sufficient, 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 the FRR Entity shall be assessed an FRR Commitment Insufficiency Charge. The amount of this charge shall be equal to two times the CONE for the relevant location, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation, including any Threshold Quantity requirement, for the remaining term of the plan. Id.

4. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource that has cleared in any RPM auction for such Delivery Year. An FRR Entity may include in its FRR Capacity Plan Capacity Resources obtained from another FRR Entity, provided, however, that each FRR Entity is responsible for meeting its own capacity obligations and that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year. Id. at section II.O.4, page 38.

An FRR Entity that designates Capacity Resources in its FRR Capacity Plan for a Delivery Year based upon a Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in an RPM auction, provided, however, that such sales must not exceed an amount equal to the lesser of (a) 25% times the

Unforced Capacity equivalent of the IRM for such Delivery Year times the Preliminary Forecast Peak Load for which the FRR Entity is responsible under its plan for such Delivery Year, or (b) 1300 MW. Id.

An FRR Entity that designates Capacity Resources in its FRR Capacity Plan for a Delivery Year based upon a Threshold Quantity may not offer to sell such resources in any RPM auction, but may use such resources to meet any increased capacity obligation due to unanticipated load growth, or may sell such resources outside the PJM region or to another FRR Entity. Id.

An entity that selects the FRR Alternative for only part of its load in the PJM Region that designates Capacity Resources as Self-Supply in an RPM auction to meet its expected Daily Unforced Capacity Obligation shall not be required, solely due to such designation, to identify Capacity Resources in its FRR Capacity Plan based on the Threshold Quantity. However, such entity may not designate Capacity Resources in excess of the lesser of (a) 25% times the entity's total Unforced Capacity Obligation or (b) 200 MW. An entity can avoid this limitation by identifying Capacity Resources in its FRR Capacity Plan based on the Threshold Quantity. Id. at pages 38-39.

5. FRR Daily Unforced Capacity Obligations and Deficiency Charges

The Settlement Agreement (at section II.O.5) provides that an FRR Entity's Daily Unforced Capacity Obligation will be determined each month on a daily basis for each Zone, in accordance with rules in Section F of Schedule 8.1 to the RAA. The FRR Entity will be assessed an FRR Capacity Deficiency Charge if it fails to satisfy its Daily Unforced Capacity Obligation in a Zone. The charge will be equal to the deficiency below the FRR Entity's Daily Unforced Capacity Obligation times twice the applicable Cost of New Entry.

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 for municipal annexations, as discussed below. Id.

6. Capacity Resource Performance

The Settlement Agreement (at section II.O.6) provides that capacity resources committed by an FRR Entity in its Capacity Plan shall be subject to many of the same performance and penalty charges as resources committed to serve load through the RPM auctions. However, the deficiency rates for FRR resources will be tied to Net CONE, rather than to the RPM auction clearing price. The Settlement Agreement (at P. 40)also provides that an FRR Entity will have the same opportunities to cure resource deficiencies during the Delivery Year and avoid or reduce associated charges as an RPM resource owner under Sections 7 and 10 of Attachment DD to the PJM Tariff. An FRR Entity also may cure deficiencies and avoid and or reduce associated charges prior to the Delivery Year by procuring replacement capacity outside of any RPM auction and committing such capacity in its FRR Capacity Plan. Id.

7. Annexation

The Settlement Agreement (at section II.O.7) also provides rules that address how to handle load that moves between RPM LSEs and FRR entities (in either direction) as a result of municipal annexation.

8. Savings Clause for State-Wide FRR Program

The Settlement Agreement (at section II.O.8) also adds the following savings clause to the FRR eligibility provisions of the RAA:

> Nothing herein shall obligate or preclude a state, acting either by law or through a regulatory body acting within its authority, from designating the Load Serving Entity or Load Serving Entities that shall be responsible for the capacity obligation for all load in one or more FRR Service Areas within such state according to the terms and conditions of this Settlement Agreement and the PJM Tariff and Reliability Assurance Agreement. Each LSE subject to such state action shall become a Party to the PJM Reliability Assurance Agreement and shall be deemed to have elected the FRR Alternative.

9. FRR Interaction with RTEP

The Settlement Agreement (at section II.O.9) recognizes several principles concerning interaction of the FRR Alternative with the RTEP process: including that: (i) when the FRR Alternative has been elected as to all load in an LDA, the RTEP market efficiency analysis will not consider payments for each capacity within that LDA; (ii) an FRR Entity may include in its FRR Capacity Plan a transmission upgrade that increases the CETL into the LDA served by the FRR Entity and reduces the LDA's reliance on Capacity Resources located within the LDA; and (iii) any Party's election of the FRR Alternative will not change PJM's planning analysis for reliability-based transmission upgrades or enhancements.

R. Other Issues

The Settlement Agreement (at section II.P) also addresses certain other issues, as follows:

- The agreement provides that a forum will be established for discussion dedicated to increase coordination among PJM, state siting authorities, regulatory commissions, and PJM stakeholders to identify, evaluate, and hopefully rectify, any barriers to entry of investment in generation, transmission, and demand response.
- The agreement requires that as part of the annual State of the Market Report, the PJM Market Monitoring Unit will analyze and identify barriers, if any, to infrastructure development in each LDA

- The agreement commits the Settling Parties to establish additional process within the PJM region for pursuing and supporting demand response and incorporating energy efficiency applications

- The agreement amends Section 5.14 of Attachment DD to clarify that the Locational Reliability Charge is assessed for each Zone (rather than an LDA), including Zones composed of multiple LDAs

- The agreement expressly acknowledges that it fulfills the obligations of Paragraph 10 of the Settlement Agreement filed and approved in *PJM Interconnection, LLC*, Docket No. EL03-236

- The agreement commits PJM to file separately to address appropriate charges and credits as necessary to reflect locational price differences in capacity exported from the PJM region

- The agreement expressly states that nothing in the agreement shall preclude the development of a long-term market design that does not rely upon an administrative capacity construct at a later time

The Settlement Agreement (at section II.P) also amends Attachment DD to clarify and correct errors, omissions, and inconsistencies in the August 31st Filing, including (but not limited to):

- determinations of the LDAs and increases in import capability associated with a Qualifying Transmission Upgrade (e.g., Section 5.6.1(g) and 5.14(d));

- clarification to Interruptible Load for Reliability payment provisions (e.g., Section 11(b));

- rules to ensure that incremental Capacity Transfer Rights ("CTRs") do not exceed the total CTRs available to loads in any LDA (e.g., Section 5.15 and 5.16 of Attachment DD); and

- rules governing the allocation of CTR credits in nested LDAs (e.g., section 5.15 of Attachment DD).

8. Filing Rights

The Settlement Agreement provides at Section III that nothing in the agreement shall be construed as affecting in any way PJM's right unilaterally to make application to the Commission for a change in rates, terms and conditions under section 205 of the

Federal Power Act and the Commission's regulations thereunder; or as restricting any rights of the other parties under the Federal Power Act, including rights under section 206. The Settlement Agreement further provides that, before PJM's exercise of its 205 rights with respect to changing the Reference Resource or the CONE Areas, PJM shall (i) hold at least one stakeholder meeting to discuss the proposed changes, and (ii) provide stakeholders at least 15 calendar days' notice of any such stakeholder meeting.

T. Approval and Effective Date of Settlement Agreement

The Settlement Agreement provides at Section IV that the parties shall seek and cooperate in securing Commission approval of the agreement, and that the agreement shall become effective as of the date on which the Commission approves or accepts it in its entirety, including the appended revised tariff sheets, without condition or modification.

The Settlement Agreement further provides that if the Commission does not approve the agreement by December 22, 2006, the agreement shall terminate unless the Settling Parties agree to an extension. If the Commission should condition its approval of the Settlement Agreement or seek to require modification of any of the terms of this Settlement Agreement, the Settling Parties shall confer and either accept the condition or negotiate in good faith, if necessary, to restore the balance of risks and benefits reflected in the agreement as executed. If no agreement can be reached within fifteen (15) days of the date of issuance of the Commission's order, and unless all of the Settling Parties agree to extend the time period for such negotiations, the Settlement Agreement shall terminate.

U. Miscellaneous Provisions

The Settlement Agreement also includes, at Section V, standard settlement provisions and miscellaneous agreement provisions concerning such matters as the amendments to the PJM Tariff and agreements; use of the just and reasonable standard and not the public interest standard; disclaimer of any admission or precedent; integration of the agreement; confidentiality of settlement discussions; commitment as to further assurances; effect on successors and assigns; authorization to execute; and execution in counterparts.

III. REQUIRED INFORMATION

In accordance with the Chief Administrative Law Judge's October 15, 2003 Notice To The Public, the Settling Parties provide the following information:

A. Issues Underlying the Settlement and Major Implications

The issues underlying the Settlement Agreement are: (1) the justness and reasonableness of PJM's existing capacity construct; and (2) the content of a just and reasonable replacement for PJM's existing capacity construct. The Settling Parties agree that the Settlement Agreement resolves all issues in this proceeding.

B. Policy Implications

The issues settled in this proceeding do not require the Commission to examine or change any existing policy or procedure.

C. Other Pending Cases

The Settlement Agreement does not affect any other pending proceeding, however, as noted above, the Settlement Agreement fulfills the obligations of Paragraph 10 of the Settlement Agreement filed and approved in *PJM Interconnection, L.L.C.*, Docket No. EL03-236.

D. Issues of First Impression or Reversals on Issues

The Settlement Agreement does not involve issues of first impression, nor are there any previous reversals on the issues involved.

E. Applicable Standard of Review

The standard of review of the Settlement Agreement is the just and reasonable standard.

IV. CONCLUSION

For the foregoing reasons, the Settlement Agreement is just and reasonable, and the Settling Parties respectfully request that the Commission approve the Settlement Agreement without amendment, modification, or condition.

Respectfully submitted,

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and on behalf of the
Settling Parties

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment A
Supplemental Affidavit of
Andrew L. Ott

**UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION**

PJM INTERCONNECTION, L.L.C.	)	**Docket Nos. ER05-1410-000 and EL05-148-000**

**SUPPLEMENTAL AFFIDAVIT OF ANDREW L. OTT
ON BEHALF OF PJM INTERCONNECTION, L.L.C.
ON SETTLEMENT AGREEMENT**

I, Andrew L. Ott, being duly sworn, depose and state as follows:

My name is Andrew L. Ott, and I am the Vice President of Market Services for PJM Interconnection, L.L.C. ("PJM"). I previously submitted affidavits in this proceeding in support of PJM's August 31, 2005 initial filing ("August 31 Affidavit") on its proposed Reliability Pricing Model ("RPM"); in support of PJM's May 19, 2006 brief on the RPM issues set for consideration in a paper hearing; and on May 30, 2006, for consideration in the Commission's June 7-8, 2006 Technical Conference in this proceeding. I am submitting this supplemental affidavit in support of the September 29, 2006 "Settlement Agreement and Offer of Settlement" in this case ("Settlement"), to which PJM is a signatory, and to address two of the changes effected by the Settlement to PJM's previously filed position in this case. Specifically, in this affidavit, I will:

- explain that the revised Variable Resource Requirement ("VRR") Curve established by the Settlement meets the reliability objectives I described in my August 31 Affidavit; and

- Explain the impact of the reduction of the forward commitment period from four years to three, and

- describe the benefits of the *Peak-Hour Period Availability Charge/Credit* that has been added to RPM by the Settlement.

I. Variable Resource Requirement Curve

As I explained in my August 31 Affidavit, a VRR curve has significant advantages over the single-value installed capacity approach used in PJM's current capacity market, under which prices are very high if there is a shortage of only a few megawatts below the installed reserve margin, but drop to zero if there is a surplus of only a few megawatts of excess capacity above the IRM level. Moreover, because a more gradually downward-sloping VRR curve recognizes that additional capacity over and above a target reserve margin has value, such a curve should help reduce the capacity price volatility that has been observed in the current PJM daily capacity market.

As I explained, the goal of capacity market reform should be to provide greater assurance of a stable and sustainable supply adequacy. The sloped VRR curve coupled with forward capacity procurement helps satisfy this goal.

I participated actively on behalf of PJM in the settlement negotiations in this case, and I am satisfied that the VRR Curve adopted in the Settlement Agreement ("Settlement Curve") is likely to meet these objectives.

Although the Settlement Curve establishes a lower value for capacity at most capacity levels, it retains an important element, in that it ties the Net Cost of New Entry to a cleared capacity level equal to the Installed Reserve Margin plus one percent. PJM's analyses throughout this proceeding have found the shift of one percent to the right above IRM for the Cost of New Entry reference point to be a key parameter in the performance of a VRR Curve, and the Settlement Curve properly retains this important feature.

While the Settlement Curve is likely to result in lower initial capacity costs (as compared to the VRR Curve proposed in PJM's initial filing in this case), the Settlement Curve performs well on the key measures of long-term reliability and long-term total cost to consumers (which includes both capacity and scarcity costs), as shown by Professor Benjamin F. Hobbs in his supplemental affidavit. The expected reliability level shown in his simulations, i.e., that the Settlement Curve is likely to lead to reserve levels meeting or exceeding the Installed Reserve Margin 95% of the time, provides in my view reasonable assurance that the PJM Region will continue to meet reliability objectives. Moreover, the long-term consumer costs shown in his model, while slightly higher than those for the originally proposed curve, are not excessively increased.

My support for the Settlement Curve, and my willingness to recommend it to the PJM Board, is influenced by the settlement provisions that, I am advised, preserve PJM's right to file unilaterally at FERC for a change in the VRR Curve or other RPM terms and conditions. If the VRR Curve does not perform as expected, and if reliability concerns arise, I will not hesitate to recommend to the PJM Board that they exercise that authority, and change the VRR Curve or its parameters (such as the Cost of New Entry) if warranted by the circumstances.

II. Forward Commitment Period

As I explained in my August 31 Affidavit, the short-term nature of the current PJM capacity market and current capacity obligation rules are fundamentally inconsistent with the need to preserve system reliability over the long term. By contrast, a forward commitment and forward capacity pricing regime that provides a direct opportunity for planned generation, planned transmission upgrades, and planned demand resources to compete with existing resources will provide more certainty to PJM, to regulators and to market participants concerning long-term reliability of the grid. As I stated previously in this proceeding, the key consideration in the determination of the length of the forward commitment period is to provide the ability for planned resources to directly compete with existing resources in the Base Residual Auction. As explained by Mr. Raymond L.

Pasteris in his August 31, 2005 affidavit, the development time for a typical combustion turbine plant is slightly less than 3 years. Therefore I am satisfied that the reduction in the forward commitment period from four years to three years will not preclude competition from planned resources in the Base Residual Auction.

Another aspect of the forward commitment period is to provide stable forward price signals to encourage long term forward contracting which will provide the market with greater forward certainty concerning both capacity price and capacity adequacy. While a three year forward commitment is somewhat shorter than the originally proposed four year commitment period, the three year forward commitment is a significant improvement over the current PJM capacity construct which requires only a day-to-day capacity commitment. As I stated at the previous FERC technical conference on RPM, there is no practical way to determine the optimal forward commitment period. I stated my belief that a forward commitment period of three to five years should be workable within the RPM construct. I also note that PJM originally chose the four year forward as a balanced approach to satisfying stakeholder interests.[1]

For the reasons stated above, I am satisfied that the reduction from a four year forward commitment to a three year forward commitment will not significantly reduce the performance of RPM in providing stable, long-term price signals and in incenting infrastructure investment.

III. Peak-Hour Period Availability Charge/Credit

The Settlement Agreement properly adds a Peak-Hour Period Availability Charge/Credit to RPM. This provision establishes a means to assess whether generation resources committed as capacity actually are available at expected levels during peak periods, and credits or charges resources to the extent they exceed or fall short of that expected availability. This will provide generation owners a significant added incentive to ensure that their capacity resources are available when they are most needed, and provide loads greater assurance that their payments for capacity will help maintain peak-period reliability. The negotiated provision also includes protections for sellers, primarily by limiting their maximum exposure to these charges.

Such a provision is a natural addition to the RPM construct. RPM is designed to ensure that sufficient generation capacity is available to satisfy reliability requirements at peak system demand conditions. Although RPM's objective is in part to ensure sufficient capacity is available to satisfy peak energy demand, the original RPM design did not have any provisions to directly measure performance in the energy market. The RPM model has been enhanced by the addition of these availability metrics. The addition of the

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1 At the technical conference and in previous testimony in this proceeding, some stakeholders favored at most a single-year forward commitment while others advocated up to a ten-year forward commitment requirement.

peak hour period availability metric through the Settlement Agreement will allow PJM to directly measure generation availability performance during peak load periods. These peak hour periods are defined based on the winter and summer operating periods when high demand conditions are likely to occur and therefore when generation performance is most critical to maintaining system reliability. The addition of the peak hour period availability metric is beneficial because it will augment the ability of PJM to preserve and maintain the reliability of the PJM Region by providing direct performance incentives to generation in these periods.

The RPM construct also is designed to ensure that capacity market prices are consistent with system reliability metrics. All network customers must satisfy their capacity obligation either through the RPM or through the Fixed Resource Requirement alternative. Since generation receives capacity payments, or in the case of the FRR is committed to directly satisfy load obligation requirements, there is an expectation that the generator will provide reliability services when required. The peak hour period availability metrics are imposed on generation that receives capacity payments through the RPM market or are specified in a long term fixed resource plan. The metrics provide consumers, who have paid for a high level of reliability through their capacity market payments, with reasonable assurance that generation will perform at adequate levels during peak period hours.

This concludes my affidavit.

SS:) Commonwealth of Pennsylvania
) County of Montgomery
)

AFFIDAVIT OF ANDREW L. OTT

Andrew L. Ott, being first duly sworn, deposes and says that he has read the foregoing "Supplemental Affidavit of Andrew L. Ott," 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/ ____________________
Andrew L. Ott

Subscribed and sworn to before me this 29th day of September, 2006.

/s/ Renee L. Doganieri
Notary Public

My Commission expires: August 25, 2007

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Renee L. Doganieri, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Aug. 25, 2007
Member, Pennsylvania Association Of Notaries

ORIGINAL

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September 29, 2006

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

2 of 4

Re: Settlement Agreement and Explanatory Statement of the Settling Parties Resolving All Issues in PJM Interconnection L.L.C., Docket Nos. ER05-1410-000 and -001, and EL05-148-000 and -001

Dear Ms. Salas:

PJM Interconnection, L.L.C. ("PJM"), pursuant to Rule 602 of the Commission's Rules, submits for filing, on behalf of itself and the parties listed in the enclosed Settlement Agreement (collectively "Settling Parties"), an original and 14 copies of the settlement documents described below.

I. Description of the Filing

The Settlement Agreement filed herein resolves all issues regarding the implementation by PJM of a reliability pricing model ("RPM") to replace PJM's existing capacity obligation rules, without the need for an evidentiary hearing or further proceedings. Therefore, the Settling Parties respectfully request that the Commission approve the Settlement Agreement, including the enclosed revised sheets of the PJM Open Access Transmission Tariff ("PJM Tariff"), PJM Operating Agreement, and the enclosed new Reliability Assurance Agreement for the PJM Region ("RAA"), as set forth in Attachments A through F to the Settlement Agreement.

II. Documents Enclosed

The Settling Parties submit the following settlement materials:

1. Explanatory Statement, including appendices containing supplemental affidavits of Mr. Andrew L. Ott, Mr. Joseph E. Bowring, and Mr. Benjamin F. Hobbs, on behalf of PJM; Mr. Paul Williams, on behalf of the Portland Cement Association; and Mr. Robert Stoddard, on behalf of Mirant.

2. Settlement Agreement, including appendices containing revised sheets to the PJM Tariff, Operating Agreement and RAA;

3. Proposed Letter Order; and

4. Certificate of Service.

III. Comment Dates

Pursuant to Rule 602(f)(2), comments on the Settlement Agreement must be filed with the Secretary within 20 days of the filing of the settlement, i.e., on or before October 19, 2006, and reply comments must be filed with the Secretary within 30 days of such filing, i.e. on or before October 30, 2006.

IV. Request for Review and Waiver

The Settlement Agreement provides that the RPM construct shall replace PJM's current capacity construct beginning on June 1, 2007, which is the first day of the next annual Delivery Year under the new capacity rules. To permit this implementation date, PJM must conduct the Base Residual Auction for the 2007-2008 Delivery Year in April 2007; therefore, PJM and the market participants must begin to implement the necessary systems and business practice changes as soon as possible. To that end, the Settling Parties are asking the Commission to approve the Settlement Agreement by December 22, 2006. To the extent necessary, waiver of the Commission's notice requirements is requested.

V. Service and Request for Waiver of Posting Requirements

Pursuant to Rules 602(d) and 2010 (18 C.F.R. §§ 385.602(d) & 2010), PJM has served, either by paper or electronic service, the settlement documents listed in section II above, on all the parties listed on the official service list compiled by the Secretary in this proceeding, all PJM members, and all state commissions in the PJM Region.

With regard to service on the PJM members and the state commissions, PJM requests waiver of the posting requirements, so as to permit electronic service rather than paper service. Waiver of paper service is consistent with the Commission's decision to establish electronic service as the default method of service on service lists maintained by the Commission Secretary for Commission proceedings.[1] While Order No. 653 did not amend the posting requirements, application of its rules to tariff filings would be consistent with the Commission's "efforts to reduce the use of paper in compliance with the Government Paperwork Elimination Act."[2] Applying amended section 385.2010(f) to

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1 See Electronic Notification of Commission Issuances, Order No. 653, 110 FERC ¶ 61,110 (2005).

2 Id. at P 2, citing 44 U.S.C. § 3504.

this filing, PJM will post this filing today to the FERC filings section of its internet site, http://www.pjm.com/documents/ferc.html, and send an e-mail to all PJM members and all state utility regulatory commissions in the PJM Region[3] alerting them that this filing has been made by PJM today and is available by following such link. Within one business day, PJM will send a second e-mail to the same list, containing a link that takes the recipient directly to the filed document.[4]

Respectfully submitted,

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Encl.
cc: Service List

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3 PJM already maintains, updates, and regularly uses e-mail lists for all Members and affected commissions.

4 PJM anticipates that in unusual circumstances, it may not be possible to post the document to its website on the day of filing, or to distribute an active link to the document within one business day. Consistent with §385.2010(i)(3), if a link to the document does not become available within two business days after filing, PJM will arrange for immediate service by other means.

Attachment B
Supplemental Affidavit of Joseph E. Bowring

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.	)	**Docket Nos. ER05-1410-000 and EL05-148-000**

SUPPLEMENTAL AFFIDAVIT OF JOSEPH E. BOWRING ON BEHALF OF PJM INTERCONNECTION, L.L.C. ON SETTLEMENT AGREEMENT

My name is Joseph E. Bowring and I am the PJM Market Monitor. My business address is 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403. Since March 1999, I have been responsible for the market monitoring activities of PJM, as defined by the PJM Market Monitoring Plan, Attachment M to the PJM Open Access Transmission Tariff. I am a Ph.D. economist and have substantial experience in applied energy and regulatory economics. I have taught economics as a member of the faculty at Bucknell University and at Villanova University. I have served as a senior staff economist for the New Jersey Board of Public Utilities and as Chief Economist for the New Jersey Department of the Public Advocate's Division of Rate Counsel. I have also worked as an independent consulting economist.

I previously submitted an affidavit in this proceeding to explain and support several aspects of PJM's August 31, 2005 initial filing on its proposed Reliability Pricing Model ("RPM"). I am submitting this Supplemental Affidavit to explain and support several changes to PJM's initial filing effected by the September 29, 2006 Settlement Agreement ("Settlement") in this proceeding. In particular, in this affidavit, I will:

- explain that the revised methodology used in RPM to calculate the net energy and ancillary services revenue offset is consistent with the objectives I described in my prior affidavit both for the calculation of Net CONE and the calculation of offer caps for specific units; and

- explain why identified, revised portions of the market power mitigation rules included in the settlement are consistent with the objectives I described in my prior affidavit.

I. Net Energy and Ancillary Services Revenue Offset Against the Cost of New Entry

RPM uses a variable resource requirement curve ("VRR Curve") to represent the demand side in each RPM auction market. The cost of new entry ("CONE") for a combustion turbine ("CT"), net of the revenues such a unit would receive in the energy and ancillary services markets ("Net CONE"), is a key parameter of the VRR Curve and therefore of the maximum price that will be paid for capacity under various supply conditions.

If a new unit is to recover all of its costs from the PJM markets in equilibrium, the unit needs to recover from the capacity market only those costs not recovered in the other PJM markets. A competitive offer price in the RPM market for a new CT for its first year of operation equals the total annual fixed costs of the CT, less expected net revenues from all other sources. This is the incremental cost of new capacity. Accordingly, the CONE value must be reduced by an amount equal to the revenue a new CT can expect to receive from the PJM energy and ancillary services markets, less the variable expenses incurred to obtain those revenues ("revenue offset").

Net revenue, as applied in the RPM context, is the contribution to fixed costs received by generators from PJM energy and ancillary services markets.[1] Gross energy market revenue is the product of the energy market price paid for the output and the generation output. Gross revenues are also received from ancillary services markets. Net revenue equals total gross revenue less variable operating costs.

The RPM proposal relies on a formula to determine this revenue offset amount for the Reference Resource. The revenue offset is based on the operating parameters of the same resource on which the CONE is based. The CONE is based on the GE Frame 7FA combustion turbine and the net capacity and net heat rate of this Reference Resource are used to calculate revenue offset values based on historical data from defined time periods.

The Settlement modifies the initial RPM filing and uses the following to define the historical time period used to calculate the net revenue offset for CONE: "For each of the first three Delivery Years of the Transition Period, such determination shall be based on the six consecutive calendar years preceding the relevant BRA. For any subsequent Delivery Year, such determination shall be based on the three consecutive calendar years preceding the relevant BRA." The change is that the initial RPM filing included the use of a six year period for all auctions.

The revenue offset calculation is used in RPM auctions that will determine capacity prices for Delivery Years three years in the future. The objective in the revenue offset calculation is to get the incentives right both for investors in generation and for load that will purchase capacity. Given that net revenue is calculated based on historical data, the choice is among possible numbers of years and annual weights. Investors are making decisions about constructing capacity based on expectations of energy revenues for the economic life of the facility. Thus investors are unlikely to build a unit based on

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1 The net revenues calculated in the Market Monitoring Unit's PJM State of the Market Report include capacity market revenues. Such revenues are not included here as the goal is to determine a competitive offer price in the capacity market for new entry after accounting for net revenues from all the markets except the capacity market.

the expectation that the last one or two years of net revenues represents future net revenues, especially in light of actual historical net revenue fluctuations.

I conclude that the use of a rolling three-year simple average of net revenues for the Reference Resource for the revenue offset calculation beginning after the third Delivery Year will reasonably meet the stated objective.

Nonetheless, neither PJM nor investors can perfectly predict net revenues for the operating year. One goal in calculating both the CONE and the revenue offset is to define a reasonable measure of the competitive cost of new entry while leaving room for competitive forces to actually determine the clearing price in the capacity auctions, subject to the constraint of the VRR Curve. If actual competitive participant offers are less than the estimated Net CONE, the clearing price will be lower than the Net CONE and if actual competitive participant offers are greater than the estimated Net CONE, the clearing price will be higher than the Net CONE.

Another goal of calculating the revenue offset is to provide a mechanism for equilibrating the results of the energy markets and the capacity market. If the revenue offset is high, the competitive offer price for new entry will decline correspondingly as will the Net CONE. The reverse is also true. In the absence of such an equilibrating mechanism, there is a risk that total payments from all markets could exceed or fall short of the incentives consistent with resource adequacy. In addition, such an equilibrating mechanism provides a disincentive to the exercise of market power in the energy market. If market power is exercised in the energy market so as to increase prices and net revenues, this mechanism would reduce the capacity market price correspondingly but the impact would be attenuated by the inevitable differences between the historical average revenue offset and actual delivery year results.

The revenue offset formula in the filing calculated energy market revenues using a "perfect dispatch" approach. The perfect dispatch approach assumes that a unit will operate whenever the LMP is greater than the marginal costs of the unit (fuel plus variable operation and maintenance expense). This is the simplest approach and does not take account of operating constraints like minimum run times and other similar constraints. The Settlement uses the "peak-hour" approach, also presented in my prior Affidavit, which explicitly accounts for such operating constraints for the Reference Resource. This approach produces a more refined estimate but also requires a number of detailed assumptions about how the unit would run. The relevant assumptions, as presented in my prior Affidavit, are included in the Settlement.

I conclude that the peak-hour approach, as adopted, will provide a more accurate measure of net revenues than the perfect dispatch approach and thus provide a more accurate VRR.

The same time periods identified for the revenue offset formula will be used in the determination of offer caps for individual units. However, actual net revenues for specific units will include all relevant sources of revenue depending on the unit. The actual net revenues will include, as appropriate, revenues from energy markets, ancillary services markets and operating reserves credits as well as from bilateral contracts.

I conclude that it is reasonable to apply the defined time periods from the Settlement to the calculation of actual net revenues for actual units to be used in the calculation of unit-specific offer caps. This will ensure consistency between the determination of the VRR, resultant market prices and the projected revenues for individual units.

II. Market Power Mitigation Rules

RPM includes explicit rules governing market power mitigation in the capacity market. This is an important benefit of the RPM proposal, as PJM's existing capacity market does not include explicit market power mitigation rules. As I have concluded in the 2005 and prior State of the Market Reports, market power is endemic to the current capacity market design, yet there are no explicit rules limiting the exercise of market power in the capacity market. Given that, all else equal, RPM will increase market power, e.g through the creation of smaller, regional or LDA-based (Locational Deliverability Area) capacity markets, this explicit set of market power mitigation rules is central to the RPM construct. The RPM mitigation rules are required to make the RPM construct produce competitive outcomes. At the same time, the RPM market power mitigation rules are designed to minimize intervention in the capacity markets and to explicitly permit scarcity pricing as described in my prior Affidavit.

I will address the following changes to Section 6 of the RPM rules in proposed Attachment DD to the PJM Tariff, which contains the proposed market power mitigation rules for RPM:

- Detailed application of the three pivotal supplier test;
- Definition of the competitiveness of new entry;
- Revised data submission requirements;
- CRF table modifications.

A. Three Pivotal Supplier Test

Consistent with the Commission approved test currently applied to the energy market, the market structure test uses the three pivotal supplier test. The exact method of defining the three pivotal supplier has been modified to conform with that currently applied by PJM in the energy market, consistent with PJM's statement in the RPM filing. Two changes to the filed RPM are the removal of references to net supply and the use of a market definition based on 150 percent of the clearing price.

I conclude that this is the appropriate way to apply the three pivotal supplier test and the three pivotal test is the appropriate test to apply in the RPM.

B. Definition of the Competitiveness of New Entry

The market power mitigation rules in the RPM filing assumed that new entry would be competitive. The Settlement modifies this assumption at section 6.5(a)(ii) where certain criteria and procedures for evaluating the competitiveness of new entry are specified.

I conclude that these provisions appropriately strengthen the market power mitigation provisions of the RPM while maintaining the incentives for new entry and the ability of competitive new entry to set the clearing price when appropriate.

C. Revised Data Submission Requirements

The Settlement modifies the data submission requirements at section 6.7(c) of Attachment DD. The RPM filing provided that potential participants in any RPM auction in any LDA that failed the Preliminary Market Structure Screen would have to submit specified data to permit calculation of an offer cap if required by the auction clearing results. The Settlement provides that if a unit is in an Unconstrained LDA Group and unlikely to be in a resource class that will set the clearing price, such unit will not have to submit data in the first instance. In addition, if the owner of a unit commits to offer such unit at or less than the defined proxy price for the relevant resource class, such unit will not have to submit data in the first instance. The MMU could require such data submission if the data is required for a complete evaluation of the market. The rationale for such revised data submission requirements is to reduce the data reporting requirements where the resultant data would not change the ability of the MMU to evaluate the competitiveness of the market.

I conclude that the revised data submission requirements do not affect the ability of the MMU to evaluate the competitiveness of any affected auction, especially as the MMU has the ability to obtain such data if it is subsequently determined to be necessary in a particular case.

D. Modified CRF Table in Offer Caps

The Settlement modifies an element of the offer caps in section 6.8 (a) of Attachment DD. In particular the CRF (capital recovery factor) table is modified to include additional options.

The definition of avoidable costs included in the RPM filing provided for the potential that an owner may need to make an incremental investment in a unit in order to maintain it as a capacity resource for the delivery year and for future years. The definition of avoidable costs provides for inclusion of the annual carrying costs of making such an investment (the capital recovery factors). These carrying costs include the return on and of capital including a rate of return and depreciation. The underlying financial model assumptions are identical to those used in PJM's definition of the CONE, with one important exception. The definition of avoidable costs explicitly recognizes that the useful life of a capacity investment in an existing unit is directly related to the age of the existing unit. It can reasonably be expected that an investment in a unit that is 20 years old will have a shorter useful life than an investment in a unit that is 5 years old. The capital recovery factors included in the definition of avoidable costs are therefore calculated on the basis of the age of the unit and therefore the expected remaining useful life. This provides an appropriate incentive to maintain and invest in existing capacity resources.

The Settlement modifies the CRF table by adding two new categories, i.e., the "40 Plus Alternative" category and the "Mandatory Capital Expenditures" Category.

The 40 Plus Alternative category provides for 100 percent recovery of all incremental capital costs in one year, using a CRF of 1.100. This accelerated recovery is provided for units that are either gas or oil-fired and that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding units that are receiving payments under the generation deacitivation provisions of the PJM OATT). Resources electing the 40 Year Plus Option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period. The Settlement provides that PJM shall give market participants reasonable notice of such election. Finally, the Settlement caps such offers at the Net CONE.

The Mandatory Capital Expenditures category provides for accelerated recovery of all incremental capital costs. This accelerated recovery is provided for units that must make an incremental investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year. In order to qualify a unit must be a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought and the required incremental investment is equal to or exceeds $200/kW of capitalized project cost. A unit could also qualify if it is a coal-fired unit located in a constrained LDA, began commercial operation at least 50 years prior to the date of the RPM Settlement, and the seller signed the Settlement. Finally, the Settlement caps such offers at .90 times Net CONE.

I conclude that these modifications to the CRF table component of the RPM offer caps are generally consistent with a competitive outcome.

III. Conclusions

It is my overall conclusion that these modifications made to the market power mitigation provisions of the RPM will not materially affect the ability of the MMU to ensure that market outcomes are competitive. The market power mitigation rules do not and cannot guarantee a competitive outcome, but they do provide a critical, tariff-based set of rules that will substantially increase the probability of a competitive outcome. I also conclude that the rules do not inhibit the MMU from monitoring the RPM market, from proposing modifications to the mitigation rules if necessary to prevent the exercise of market power, or from seeking specific mitigating actions from the Commission should the MMU identify a market power issue.

This completes my affidavit.

SS:) Commonwealth of Pennsylvania
) County of Montgomery
)

AFFIDAVIT OF JOSEPH E. BOWRING

Joseph E. Bowring, being first duly sworn, deposes and says that he has read the foregoing "Supplemental Affidavit of Joseph E. Bowring," 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/ Joseph E. Bowring
Joseph E. Bowring

Subscribed and sworn to before me this 29th day of September, 2006.

/s/
Notary Public

My Commission expires: August 25, 2007

COMMONWEALTH OF PENNSYLVANIA
Notarial Seal
Renee L. Dogarini, Notary Public
Lower Providence Twp., Montgomery County
My Commission Expires Aug. 25, 2007
Member, Pennsylvania Association Of Notaries

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment C
Supplemental Affidavit of
Benjamin F. Hobbs

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C. — Docket No. ER05-1410-000 and and EL05-148-000

SUPPLEMENTAL AFFIDAVIT OF BENJAMIN F. HOBBS
ON BEHALF OF PJM INTERCONNECTION, L.L.C.
ON THE SEPTEMBER 29, 2006 SETTLEMENT CAPACITY DEMAND CURVE

I, Benjamin F. Hobbs, being duly sworn, depose and state as follows:

My name is Benjamin F. Hobbs and I am a Professor of Geography and Environmental Engineering, and of Applied Mathematics and Statistics (Joint Appointment) at the Johns Hopkins University. I previously submitted an affidavit in this proceeding ("August 31 Affidavit") in connection with the August 31, 2005 filing by PJM Interconnection, L.L.C. ("PJM") to establish the Reliability Pricing Model ("RPM"). I also submitted a supplement affidavit on May 30, 2006 in response to the Commission's April 20, 2006 order on the RPM proposal ("April 20 Order"), addressing certain issues concerning the definition and analysis of alternative demand curves for capacity.

The purpose of this supplemental affidavit is to present an analysis of the demand curve agreed upon by the parties in the settlement filed on Sept. 29, 2006 (the "Settlement Curve"), and to discuss the adjustment of the assumed CONE in response to experienced capacity prices.

1. Analysis of the Settlement Curve

Assumptions. The Settlement Curve has been defined for the purposes of this simulation as connecting the following points:

- IRM-3%: 1.5*(72,000 –E/AS offset)/0.93 (in $/unforced MW/yr)
- IRM+1%: 1*(72,000 –E/AS offset)/0.93 (in $/unforced MW/yr)
- IRM+5%: 0.2*(72,000 – E/AS offset)/0.93 (in $/unforced MW/yr)

"IRM" is the installed capacity target of 115%. The "E/AS offset" is the amount that the curve is adjusted for energy and ancillary services gross margins that the benchmark turbine is assumed to be able to earn.[1] The curve to the left of IRM-3% is flat at the indicated price; the price is zero to the right of IRM+5%. All percentages are expressed in terms of the ratio of installed capacity to peak load. The capacity prices are expressed in terms of $/unforced MW/yr; to express these in $/installed MW, the denominator of 0.93—the expected unforced availability of turbines—is removed.

The analysis is based on the same approximating assumption as in the analyses in my August 31, 2005 and May 30, 2006 affidavits concerning the E/AS offset used to define the demand curve: that the offset is the same in every year. As explained on pages 25-26 of my August 31, 2005 affidavit, the average E/AS gross margin earned by the benchmark turbine during the 1999-2004 would have been $21,000/installed MW/yr under the "peak-hour dispatch" assumption.[2] This $21,000 value is the offset used to define the Settlement Curve in these simulations, according to the above definition of the curve. As an approximation, this value is treated as being the same in every year, rather than a rolling average of previous years as in the actual curve definition.

An assumption also needs to be made about what E/AS gross margins are actually earned in each year, as a function of system scarcity conditions. Reduced reserve margins will increase these gross margins, according to the 1999-2004 experience summarized in my August 31, 2005 affidavit. In this supplemental affidavit, the simulations assume that E/AS gross margins are

[1] The energy and ancillary service (E/AS) gross margin is defined as revenues net of variable operating cost. Thus, it can be viewed as the contribution of revenue to covering fixed costs.

[2] Under this assumption, the benchmark turbine (that is the basis of the CONE calculation) is assumed to be operated only during peak periods. In particular, turbines are assumed to be dispatched in four distinct blocks of four hours of continuous output for each block from the peak-hour period (between 8 a.m. and 11 p.m.) for any day when the average real-time locational marginal price is at least equal to the cost of generation (including start-up and shutdown costs) for at least two hours during each four-hour block. The blocks are assumed to be dispatched independently. This is a more realistic characterization of the dispatch, and therefore of the revenues, of the benchmark turbine for the purpose of calculating net CONE.

earned by the benchmark turbine according to the peak-hour dispatch assumption.[3] Therefore, consistent with this assumption, the benchmark turbine is assumed to earn E/AS gross margins in each year according to the lower of the two curves in Figure 3 of the August 31, 2005 affidavit, which is based on a peak-hour dispatch assumption for the benchmark turbine. That curve is $7600/installed MW/yr lower than the curve used in the base case simulations in my August 31, 2005 affidavit, where instead I assumed that the benchmark turbine would be operated in any hour in which the price exceeded the marginal operating cost.

The E/AS curve used in the below analyses is the sum of two components: (1) a $2400/installed MW/yr fixed E/AS revenue stream that does not depend on reserve margin and (2) a variable E/AS gross margin (termed "scarcity revenue" in the tables of results, *infra*) that depends on the actual reserve margin in the year. In comparison, the E/AS gross margin curve used in the base cases of the August 31, 2005 affidavit had a higher fixed component of $10,000/installed MW/yr but the same variable E/AS gross margin, and so yielded $7600/installed MW/yr more in E/AS revenue at any given reserve margin. Use of the latter curve, which assumes maximally flexible operation of the baseline turbine, including the ability to start any number of times and run for very short times, is less realistic than the peak-hour dispatch assumption with limited number of starts on a day and minimum run time.

To summarize the E/AS assumptions, the base case results I discuss below use the peak-hour dispatch-based E/AS gross margins for determining the average E/AS offset in the curves, while the actual E/AS gross margins earned in each year are simulated using the peak-hour dispatch assumption (the lower curve in Figure 3 of the August 31, 2005 affidavit). Additionally, all demand curves are evaluated under the assumption that the auction takes place three years ahead of the date in which the capacity is made available, rather than the four years assumed in my August 31, 2005 affidavit. All other assumptions are the same as in my August 31, 2005 base case

[3] See Footnote 2, *supra*.

analyses, including the use of twenty five simulations, each 100 years in length.

The sensitivity analyses are based on the same changes in assumptions described in Table 2 (page 50) of my August 31, 2005 affidavit.

Results. I now summarize base case results and sensitivity analyses for the Settlement Curve, as well as selected results for Curves 1, 3, and 4 (as defined in the August 31, 2005 Affidavit) for comparison. Curve 4 is the curve recommended by PJM in its August 31, 2005 filing, while Curve 3 is an alternative curve that is shifted 1% to the left from the recommended curve (measured in terms of installed reserve margin). Curve 1 is the "no demand curve" case, in which the demand curve is effectively a vertical line at the IRM, with the price capped at twice the CONE minus the E/AS offset.[4] Results for these curves allow me to characterize the relative performance of the Settlement Curve. First, Table 1 shows the base case results for the Settlement Curve and Curves 1, 3, and 4. Then Tables 2 and 3 provide results for Curve 4 and the Settlement Curve, respectively, under a number of sensitivity analyses.

[4] Curve 1 is evaluated in Table 1 under the assumption that all new capacity bids in at $25,000/unforced MW/yr, rather than the $0/unforced MW/yr assumed for Curves 3 and 4. The bidding assumption has only a small effect on the performance of Curves 3 and 4, as shown in my August 31, 2005 affidavit as well as in Table 2, *infra*. However, that assumption does impact the performance of Curve 1; in order to provide a conservative estimate of the relative deterioration in performance that results from using no demand curve, I use a bidding assumption for Curve 1 that is more favorable for that curve. If instead bids of new capacity are assumed to be zero, then the performance is instead as follows: 34.6% probability of meeting or exceeding IRM; -0.8% average reserve over IRM; and 145.6 $/peak MW/yr consumer payments for scarcity and ICAP.

Table 1. Summary of Base Case Results for Settlement Curve and Curves 1, 3, and 4: Average Values (Standard Deviations In Parentheses) (All Values in $/installed kW/yr, except Consumer Payments)

Curve	Reserve Indices		Generation Profit, $/installed kW/yr	Components of Generation Revenue ($/installed kW/yr)			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Curve 1. Vertical Demand Curve at IRM ("No Demand Curve")	52.2	-0.5 (0.9)	52.2 (93.2)	41.9 (72.5)	2.4	68.9 (50.3)	122.9 (99.9)
Curve 3. Alternate Curve with New Entry Net Cost at IRM (Shift Left to CT net cost at IRM)	90.2	1.1 (0.8)	14.0 (50.9)	25.8 (49.8)	2.4	46.8 (5.0)	81.6 (53.3)
Curve 4. Alternate Curve with New Entry Net Cost at IRM+1%	98.4	1.7 (0.9)	11.3 (43.0)	21.2 (41.4)	2.4	48.7 (6.6)	79.2 (44.8)
Settlement Curve	95.2	1.1 (0.7)	14.4 (49.4)	25.1 (48.2)	2.4	47.8 (6.3)	82.1 (51.7)

Table 2. Summary of Results for Curve 4 (August 31, 2005 Proposed Curve), Average Values

Curve	Reserve Indices		Generation Profit, $/installed kW/yr	Components of Generation Revenue ($/installed kW/yr)			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Base Case	98.4	1.7	11.3	21.2	2.4	48.7	79.2
Max Price = Net Cost multiplied by 1.5	96.8	1.6	11.8	21.9	2.4	48.5	79.7
Max Price = Net Cost multiplied by 1.2	94.0	1.5	12.6	22.9	2.4	48.3	80.4
Price drops to zero at IRM+10%	98.8	1.7	11.1	21.1	2.4	48.6	79.0
Original Curve: No chopoff	98.8	1.7	11.1	21.1	2.4	48.6	79.0
Low Percent CT added when profit is equal to cost	97.4	1.6	12.4	21.7	2.4	49.3	80.4
High Percent CT added when profit is equal to cost	97.6	1.7	11.5	21.5	2.4	48.6	79.3
10,000 bids for new capacity	98.6	1.7	11.2	21.2	2.4	48.6	79.0
25,000 bids for new capacity	98.7	1.7	11.1	21.1	2.4	48.6	79.0
44,000 bids for new capacity	98.8	1.7	11.0	21.0	2.4	48.6	78.9
44,000 bids for new, 20,000 for existing capacity	98.8	1.7	11.0	21.0	2.4	48.6	78.9
Zero risk aversion (0.5)	97.0	2.1	7.5	20.2	2.4	45.9	74.9
High risk aversion	90.6	1.2	23.1	28.0	2.4	53.7	91.7
High rate of decay in weights	100.0	1.6	10.5	21.1	2.4	48.1	78.3
Low decay in weights	87.4	1.6	17.8	24.3	2.4	52.0	86.1

Table 3. Summary of Results under Settlement Curve, Average Values

Curve	Reserve Indices		Generation Profit, $/installed kW/yr	Components of Generation Revenue ($/installed kW/yr)			Consumer Payments for Scarcity + ICAP $/Peak kW/yr
	% Years Meet or Exceed IRM	Average % Reserve over IRM		Scarcity Revenue	E/AS Fixed Revenue	ICAP Payment	
Base Case	95.2	1.1	14.4	25.1	2.4	47.8	82.1
Low Percent CT added when profit is equal to cost	92.2	1.1	15.3	25.7	2.4	48.2	83.1
High Percent CT added when profit is equal to cost	95.5	1.2	14.4	25.4	2.4	47.5	82.1
10,000 bids for new capacity	95.2	1.1	14.4	25.1	2.4	47.8	82.1
25,000 bids for new capacity	95.2	1.1	14.4	25.1	2.4	47.8	82.1
44,000 bids for new capacity	94.2	1.2	13.8	24.8	2.4	47.6	81.5
44,000 bids for new, 20,000 for existing capacity	94.2	1.2	13.8	24.8	2.4	47.6	81.5
Zero risk aversion (0.5)	87.8	1.6	9.5	24.6	2.4	43.5	76.5
High risk aversion	*65.7*	*0.0*	*38.2*	*43.6*	2.4	*53.2*	*107.2*
High rate of decay in weights	99.7	1.2	14.1	24.6	2.4	48.0	81.8
Low decay in weights	84.4	1.0	17.3	27.7	2.4	48.2	85.1

The qualitative conclusions concerning the comparison of Curves 1, 3, and 4 (Table 1) and the effects of alternative assumptions upon the Curve 4 results (Table 2) are the same as in my August 31, 2005 affidavit. Thus, the change from a four year-ahead to three year-ahead auction does not change the general conclusions.[5]

Turning to the comparison of the Settlement Curve results with Curves 1, 3, and 4, I make the

[5] However, it should be noted that the average "Consumer Payments for Scarcity + ICAP" are higher than reported in the August 31, 2005 affidavit for Curves 1, 3, and 4. The reason for this is that the average consumer costs includes only scarcity E/AS costs, and not the fixed component. When the assumption of a peak-hour dispatch-based E/AS curve is used in the simulation, the fixed component of the E/AS gross margin to turbines shrinks from $10,000/installed MW/yr to $2400/installed MW/yr; therefore, for a turbine to break even, it must obtain more revenue from other sources, namely capacity payments and variable (scarcity) E/AS revenues. In equilibrium, therefore, the latter increase by approximately $7600 per installed MW per year. This change also translates into an increase in calculated "Consumer Payments for Scarcity + ICAP" by roughly that much; the increase is not exact, because the equilibrium solutions change slightly and, more importantly, Consumer Payments are expressed on a $/peak MW load/yr basis, not $/installed MW/yr. Note that the total cost paid by consumers does not actually increase; this increase in "Consumer Payments for Scarcity + ICAP" is matched by a decrease in nonscarcity-related energy and ancillary services payments.

following conclusions. When the Settlement Curve is defined using a fixed average E/AS offset (rather than a rolling 3 year average, as actually would be used), Table 1 shows that its performance in terms of Consumer Cost is comparable to Curve 3, achieving a value of 82.1 $/Peak kW/yr (as opposed to 81.6 and 79.2 for Curves 3 and 4, respectively, under the base case assumptions). Its performance in terms of "% Years Meeting or Exceeding IRM" is 95.2%, which lies between Curves 3 and 4 (90.2% and 98.4%, respectively).

These differences between the Settlement Curve and Curves 3 or 4 are very small compared to the gulf between their performance and that of Curve 1 ("No Demand Curve"), which performs much worse. In particular, in comparison to the Settlement Curve and Curves 3 and 4, Curve 1 results in 50% higher consumer payments for scarcity and ICAP, and roughly half the probability of meeting or exceeding the IRM. Therefore, I conclude that the differences among Curves 3, 4, and the Settlement Curve are minor compared to the benefits of moving from the vertical curve case (analogous to the present PJM ICAP system) to RPM.

The sensitivity analysis results for the Settlement Curve, in terms of how alternative assumptions affect Consumer Payments, are qualitatively similar to Curve 4. The Settlement Curve is, however, somewhat more sensitive to risk aversion assumptions (because it has a slightly more vertical aspect than Curve 4). But this difference is not large compared to the differences between the vertical curve (Curve 1) results and the sloped demand curves.

Thus, based on this analysis, I conclude that the Settlement Curve's performance would likely be similar to that of Curve 4, which was recommended by PJM in its August 31, 2005 filing, and much better than the vertical demand curve (Curve 1).

2. Updating Procedures for the Settlement Curve: The Empirical CONE

In this section, I address the settlement's "Empirical CONE" procedure. Given that any estimate of CONE is uncertain and that generation technology is evolving, it is desirable to have a predictable and transparent procedure for changing the assumed CONE when bidding behavior and market clearing prices indicate that actual capacity costs may differ significantly from the assumed CONE. Predictability and transparency is helpful in establishing confidence in the market and in facilitating the creation of a forward market for capacity rights. It is also desirable that such a procedure not result in large swings in CONE that reflect short-term market behavior rather than changes in technology. The proposed procedure, in which the demand curve's CONE is changed by no more than the minimum of (1) 10% and (2) 50% of the difference between the assumed CONE assumed and the Empirical CONE (as defined in the settlement), is a reasonable compromise for the following reasons. First, it will yield much less year-to-year variation than the situation where the demand curve's CONE was set equal to the Empirical Cone. Second, the curve's CONE will nevertheless still move over time in the direction of the Empirical CONE if bidding behavior indicates a persistent shift in peaking technology costs.

This concludes my affidavit.

	)	State of Maryland
SS:	)	
	)	City of Baltimore

AFFIDAVIT OF BENJAMIN F. HOBBS

Benjamin F. Hobbs, being first duly sworn, deposes and says that he has read the foregoing "Supplemental Affidavit of Benjamin F. Hobbs," 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/ ______________________
Benjamin F. Hobbs

Subscribed and sworn to before me this 29 day of September, 2006.

/s/ ______________________
Notary Public

My Commission expires: May 2, 2010

ERIN SIMON
Notary Public Maryland
City of Baltimore
My Commission Expires on
May 2, 2010

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment D
Supplemental Affidavit of
Paul R. Williams

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM INTERCONNECTION, L.L.C.) **Docket Nos. ER05-1410-000 and EL05-148-000**

AFFIDAVIT OF PAUL R. WILLIAMS ON BEHALF OF THE PORTLAND CEMENT ASSOCIATION ON SETTLEMENT AGREEMENT

Q. Please state your name and business address.

A. My name is Paul R. Williams, and my business address is 150 Green Valley Circle, Dresher, Pennsylvania, 19025-1515. My business telephone number is (215) 499-6940.

Q. What is your current position and background?

A. I am the President of Liberty Energy Group, Inc ("LEG"). LEG provides strategic and tactical management services for energy and related products to heavy industrial and utility clients. LEG clients include the Portland Cement Association and its members; Mittal Steel; Eastman Chemical; Air Liquide Group; and Sterling Energy Management, LLC, a global power plant project development and operations company providing services to utility companies and independent power producers. Prior to LEG, I was Director - Energy Management for Air Liquide America, Inc., for approximately 6 months after their purchase of Messer Griesheim Industries, Inc., and was employed in the same role by Messer for approximately 4 years. Prior to Messer, I worked for Bethlehem Steel, Air Products and Chemicals, and Exelon Corporation in various energy management, risk management, project development, asset optimization, pricing and rates, and regulatory roles. I have a Bachelor of Science Degree in Electrical Engineering from Drexel University in Philadelphia, PA, with a concentration on electric power systems and electrical machines. I hold a Master of Science Degree in Engineering Management from Drexel University, which was concentrated on utility management and specifically the economic operation of bulk power systems.

Q. **What is the purpose of your statement?**

A. I am addressing the benefits of the proposed use of an Empirical Cost Of New Entry ("E-CONE") in the Reliability Pricing Model ("RPM") capacity mechanism proposed by the Supporting Parties and PJM Interconnection, LLC ("PJM") in the settlement filed in Docket Nos. ER05-1410 and EL05-148.

Q. **How would E-CONE be used within RPM, as proposed in the settlement?**

A. RPM includes a downward-sloping demand curve based on an administratively determined Cost Of New Entry ("CONE"), which is essentially an estimate of the capital carrying charges of new electric generation capacity. The value of CONE is important to the RPM mechanism because it essentially drives capacity revenues for generation suppliers and costs for consumers. Therefore, CONE needs to provide adequate compensation for generation suppliers to build adequate electric generation capacity to supply system loads, while not over-compensating generation suppliers and causing consumer prices to exceed "just and reasonable" levels.

Q. **What is the benefit of the proposed E-CONE process?**

A. PJM's RPM filing relied on an administrative determination of CONE in order to create the demand curve. This value was the subject of much debate for many valid reasons. In order for PJM to develop a CONE value, PJM Staff made a series of assumptions regarding the size and configuration of the expected marginal electric generation capacity that a competitive market would produce. The myriad assumptions were the subject of debate between generation suppliers, which would necessarily want the CONE value to be as high as reasonably possible, and consumers, which would pay less under a more conservative set of assumptions. Ultimately, the administrative wrangling over CONE values would be expected to lead to periodic over- and under-pricing within the RPM capacity construct. This outcome would be sub-optimal for both generation suppliers and consumers, as revenues to generation would alternately be inadequate to provide the necessary levels of investment for system reliability or excessive relative to the reasonable actual costs of new generation. E-CONE uses market-like dynamics, rather than an administrative process, to determine the appropriate value of CONE. The use of E-CONE avoids the need for PJM Staff to make numerous assumptions regarding the size and configuration of likely new generation capacity investments and, instead, uses actual clearing prices in the Base Residual Auction, ostensibly driven by rational bids of successful developers in PJM's footprint, to set CONE.

Q. How does E-CONE work within RPM and why is that better than the administratively determined CONE value?

A. Starting with Base Residual Auction ("BRA") number 5, which will be held in 2009 for a subsequent Delivery Year, the value of gross CONE (i.e., CONE prior to a Net Energy and Ancillary Services Revenue Offset) may be adjusted if there has been cumulative net demand for new resources in the defined "Adjustment Areas." This approach is superior to the administratively determined CONE in that it evaluates the accuracy of the CONE value only after there has been a need for actual "New Entry." Requiring this demonstration of actual need as a trigger for E-CONE calculations provides better assurances that the BRA clearing prices upon which E-CONE is calculated are being driven by the offer prices of actual, new generation investment in that Adjustment Area. Because the process provides for dynamic interaction between real-world outcomes and the CONE value used in the VRR Curve, it should provide a more realistic estimate of the actual CONE than any administratively determined CONE.

Q. How does E-CONE develop a new CONE value for use within RPM?

A. If the evaluation of CONE demonstrates that the actual offers within an Adjustment Area are within a reasonable band of the current value of CONE, then no change to the current CONE estimate is made. This bandwidth helps to avoid excessive modification to CONE, providing a more stable capacity price curve for both suppliers and consumers. However, if there is excess generation and the excess grows, or if there is less than the desired amount of generation and the shortfall grows, then the value of CONE is either decreased or increased, respectively, to adjust for the imbalance in the model.

Changes, when necessary, to the CONE value used in the price curve would be based on a three-year rolling average of the Gross Clearing CONE (i.e., the actual clearing value of capacity for that year, grossed up to reflect a back-out of the Net Energy and Ancillary Services Revenue Offsets for that year). Essentially, the new CONE value is adjusted based upon the actual projects that successfully clear the market. This is a more robust CONE determination than an administrative mechanism with all of its inherent assumptions. By using actual cleared offers that have undergone the appropriate checks for market power and any necessary mitigation, consumers' ever-present concerns about market power in PJM's footprint are reduced with respect to the key pricing point on the VRR Curve (i.e., the value at IRM + 1).

Q. Does this complete your statement?

A. Yes.

Attested By,

/ Paul R. Williams /

September 29th, 2006

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment E
Supplemental Affidavit of
Robert B. Stoddard

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	Docket No. EL05-148-000 Docket No. ER05-1410-000

AFFIDAVIT OF ROBERT B. STODDARD IN SUPPORT OF SETTLEMENT AGREEMENT

Commonwealth of Massachusetts **County of Suffolk**	ss.

CONTENTS

I, Robert B. Stoddard, being duly sworn, depose and say:

I. INTRODUCTION AND SUMMARY

1. My name is Robert B. Stoddard. I am a Vice President of CRA International ("CRA") in its offices at 200 Clarendon Street, T-33, Boston, Massachusetts 02116. On October 19, 2005, I submitted an affidavit in these dockets on behalf of Mirant Americas Energy Marketing, LP, Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC, Mirant Peaker, LLC and Mirant Potomac River, LLC ("Mirant")[1] commenting on the Reliability Pricing Model ("RPM") filings by PJM Interconnection, LLC ("PJM"). That affidavit presented my professional and educational credentials. On November 23, 2005, I filed a supplemental affidavit on behalf of the [Mirant Parties], Williams Power Company, Inc. ("Williams"), and NRG Power Marketing, Inc., Conemaugh Power LLC, Indian River Power LLC, Keystone Power LLC, NRG Energy Center Dover LLC, NRG Rockford LLC, Rocky Road Power LLC, and Vienna Power LLC ("NRG Companies"), and on February 3, 2006, I spoke on Panel 2 at the Commission's Technical Conference. Subsequently, on February 23, 2006, I filed an answering affidavit on behalf of Mirant and the NRG Companies, and on June 1, 2006, prefiled testimony on paper hearing issues on behalf of Mirant.

2. I have also been active through the settlement process on behalf of Mirant. In this capacity, I participated fully in nearly all settlement meetings and conference calls, and I had extensive personal involvement in the development and negotiation of several key aspects of the proposed market design that would be created by the proposed settlement. I have carefully reviewed the Settlement Agreement and the accompanying tariff sheets and Reliability Assurance Agreement.

3. I render this affidavit in support of the overall settlement and, in particular, two elements of the settlement: the New Entry Price Adjustment Rule and the Minimum Offer Price Rule. These two rules, although not included as part of the RPM design filed by PJM last year, make

[1] At the time that I submitted my Affidavit on October 19, 2005, the Mirant Parties were: Mirant Americas Energy Marketing, LP ("MAEM"), Mirant Chalk Point, LLC, Mirant Mid-Atlantic, LLC, Mirant Peaker, LLC ("Mirant Peaker"), and Mirant Potomac River, LLC. Since that time, MAEM has ceased to conduct any active business, and has transferred its assets to Mirant Energy Trading, LLC ("MET"), which is also an intervenor in these proceedings. Likewise, Mirant Peaker has merged into Mirant Chalk Point. As a result, the Mirant Parties, as referred to herein, included MET, instead of MAEM, and do not include Mirant Peaker.

good economic sense either in that market design or in the design as modified by the Settlement Agreement, inasmuch as they will create market prices for capacity that are less susceptible to swings created either by the inherent "lumpiness" of investment or by attempts to depress wholesale prices by needlessly overbuilding capacity. With these two rules, therefore, capacity market prices will more closely reflect the actual marginal cost of meeting system resource adequacy.

4. As with all settlements, the proposed Reliability Pricing Model (the "RPM") market design reflects a number of compromises necessary to resolve this case without litigation. With this background in mind, it is my professional opinion that it is a reasonable market design. It is not necessarily the only market design that could work to accomplish these goals, but it is a workable design that reflects a widely-supported compromise of suppliers, buyers and regulators. Given the settlement posture of this case, however, my opinion should not be construed out of context as my support or the support of my client for specific individual components, or for any aspect of the market design as it might be implicated in other proceedings.

II. New Entry Price Adjustment

5. In its May 19, 2006 brief on paper hearing issues, PJM proposed the addition of a pricing rule to allow new units to set the clearing price for several years in small, import-constrained areas.[2] The nub of the issue is this: the size of a single, efficient generating plant may be several times larger than the annual load growth in a locational delivery area ("LDA"). Building such a unit would sharply lower the capacity clearing price in that LDA until the surplus created by the investment can be absorbed by load growth. As I have described in earlier testimony, this effect would lead to a saw-tooth pattern of prices and may undermine investment in capacity. The New Entry Price Adjustment Rule in the Settlement Agreement provides that a large, new unit selected in the Base Residual Auction ("BRA") in an import-constrained LDA may be offered in the next two BRAs at the lower of its first-year bid or 90 percent of Net CONE. If it does so and is selected in the BRA, the unit is paid no less than its first-year offer price, while other capacity resources would receive the (potentially lower) capacity clearing price.

[2] Brief of PJM Interconnection, L.L.C. on Paper Hearing Issues (May 19, 2006) at 36-37.

6. Furthermore, during this three year period, PJM will model the LDA with its own VRR curve. This is a necessary design element of the rule. If the import constraint was modeled only in the first year, then the unit that was needed in that year to meet the LDA's reliability requirement would *appear* not to be needed in subsequent years. Without this unit, however, the LDA would not meet its locational reliability requirement. Therefore, to give meaning to the ability to bid at a meaningful level in the second and third years as a new resource, PJM must continue to model the LDA as a potentially constrained region.

7. The Settlement Agreement's New Entry Price Adjustment rule strikes a reasonable balance between two competing views of how capacity clearing price should be set when load growth is met entirely with surplus capacity built in an earlier year. One view is that, the price should remain equal to the first-year offer price of the resource, reflecting the price paid to that resource and the fact that the overbuild resulted from a technological limitation. An alternative view is that it should fall to the VRR curve value, regarding the surplus capacity as a free good. If the first view prevailed, the price could remain at or above Net CONE for several years even when no new capacity was required, potentially causing yet more new capacity being built in response to the high price. If the second view prevailed, we would have left unaddressed the inefficiencies created by the saw-tooth prices. The proposed New Entry Price Adjustment rule finds a middle path that damps harmful price volatility while avoiding sending a false "build" signal to the market.

III. MINIMUM OFFER PRICE RULE

8. The Minimum Offer Price Rule ("MOPR") is a mechanism to limit the effect on wholesale capacity prices that could occur if buyers with a net short position purchase or build new capacity in excess of market needs, thereby artificially suppressing the price of existing resources it obtains through the RPM. This rule should, in my profession opinion, reduce the incentive of buyers to undertake such wasteful over-investment in new capacity without restricting their ability to engage in, and realize the full value of, commercially reasonable bilateral contracts to provide for loads' future reliability needs.

9. The MOPR is important to the proper functioning of the RPM. Without it, a two-tiered pricing system will likely develop, where new resources are paid a competitive New CONE through bilateral contracts, while existing resources (providing exactly the same reliability

services) are paid an RPM clearing price that has been suppressed through overbuilding that serves little purpose except to suppress capacity prices.[3] If the RPM price were consistently lower than the price being paid to new entrants paid through contracts, this will weaken the market. Only resources qualifying for, willing, and able to enter into such contracts would enter, since spot RPM prices would be artificially low. Furthermore, it would suppress the development of demand-side resources, because customers would not see the to the full cost of maintaining resource adequacy in the capacity price.

10. The need for a MOPR is perhaps best illustrated by example. Consider this hypothetical: an import-constrained LDA has a locational requirement of 15,000 MW, currently met by internal resources and imports totaling 15,300 MW. No new resources are needed, and if no new resources come on line, the fact that supply is 102% of requirements will lead to a market price of 80 percent of Net CONE.[4] If Net CONE is $120/MW-day, the RPM price would be $96/MW-day and total payments by load in the LDA will be $536,112,000, as shown in Exhibit RS-2.

11. Suppose one LSE in that LDA has a net short position of 1,500 MW, 10 percent of the locational requirement. To cover that net short position in the RPM auction, its cost will be $53,611,200.[5] Seeking to reduce its costs, the LSE considers another option: buying capacity bilaterally. It has two options:

a. It can solicit bids for capacity resources generally. Existing resources may consider responding to the RFP and offering a price near the expected spot-market price of $96/MW-day (80 percent of Net CONE). New resources, however, would not be expected to win the solicitation, since their likely offer

[3] My concern on this point is not merely hypothetical, but is borne out by a recent Request for Proposals issued by the Connecticut Department of Public Utility Control, seeking "new or incremental capacity" (and explicitly noting that "[e]xisting resources will not be considered eligible under this procurement process."), and such new capacity will be required to submit bids into the New England Forward Capacity Market ("FCM") in a way narrowly tailored to be as low as possible without triggering the rule analogous to the MOPR, regardless of actual costs. Connecticut will pay the difference between the bid cost and the revenue requirements of the new suppliers through supplemental contract payments. But for the existence of the MOPR-like rule in the FCM, the opportunity to suppress prices and distort market outcomes would be even greater.

[4] I assume throughout that the offer prices from existing supply are low enough to clear all existing supply.

[5] This figure is not the same as the net short position times the clearing price because the LSE also has responsibility to buy 10% of the cleared resources above the IRM, 30 MW.

would be closer to Net CONE. While a bilateral contract with existing resources may provide benefits such as greater long-term price certainty, it would not necessarily lead to a discount from the RPM prices.

b. It can solicit bids for *new* capacity resources, but only for a portion of its net short position. Although the cost *per MW* of new capacity will be higher than the cost of existing resources in this hypothetical, the *total* cost of meeting the LSE's capacity needs may be lower depending on how that new resource is bid into RPM. Adding new resources into the market lowers the RPM clearing price formulaically. Thus the higher per-MW cost of a relatively small quantity of new MWs can be offset by the reduction in the market-clearing price the LSE pays to cover its remaining short position.

12. Suppose in particular that the LSE in question decides to build (either on its own balance sheet or by contract) a new 300 MW resource. The extra resources, equal to 2 percent of the LDA's requirement, drives the reserve margin up to 104% and the price down to 40 percent of Net CONE, or $48/MW-day—half of the price that would otherwise occurred, thereby roughly halving the cost of covering its remaining 1,200 MW of net short position.[6] If the LSE paid the full gross Cost of New Entry ("CONE") for the new resources it built, its one-year savings would be $18,396,000, about one-third of the total cost without this new-build strategy. Even if it paid *twice* CONE for the new capacity, the LSE would still save $5,256,000 in the first year.

13. I have prepared a chart, Exhibit RS-3, that shows how capacity payments are sharply reduced by this overbuilding. Unlike most graphs of the VRR, this one plots the entire range of the VRR, from 0 MW to IRM+5, demonstrating just how steep the VRR is. The market outcome is at 80 percent of CONE, and payments are the shaded green rectangle. By buying 300 MW at a price of 100 percent of CONE, the 15,300 MW of existing capacity resources are repriced to 40 percent of CONE, and total consumer payments is the area below the red line.

14. The example shows two important parts of the issue:

a. First, in order to benefit from this behavior, the LSE needs to have a net short position in the market *after* considering its bilateral purchases and owned

[6] The cost is not exactly halved, because the LSE also must by an additional 30 MW of capacity resulting from the overbuild.

assets. The key to the overbuild strategy is to offset above-market bilateral costs paid to cover part of a net short position with depressed market prices to cover the remaining, unhedged position.

b. Second, the quantity of new resources has to be large enough to lower market prices materially. Otherwise, the savings on the unhedged position would not be large enough to offset the above-market costs paid for the new resources.

15. The MOPR, as proposed, therefore includes a net-short test and impact tests, which provide reasonable assurance that the MOPR will not change the market price unless warranted to restore the price to a competitive level:

16. **Net Short Test.** Resources offered by (or under contract to) parties that do not have a significant net short position in the LDA are presumed to be offered in competitively. For example, if an independent power producer is willing and able to build a generation resource with *no* capacity payment, its bid of zero would not be repriced by the MOPR since the developer is not net short of capacity. Likewise, if a buyer wants to purchase or self-provide its entire capacity obligation, leaving itself without a net short position in the BRA, the MOPR will not apply to its bilateral purchases.

17. **Impact Tests.** The MOPR includes two impact tests that are designed to limit the application of the rule to situations where the oversupply is unlikely to have a legitimate purpose:

a. *Offer price threshold.* PJM should not reprice legitimate offers of new supply that reflect the resources' actual economics but are simply less costly than expected. Therefore, offers that are within 20% of the class-specific Net CONE estimate, or (if there is no class-specific Net CONE estimate for the resource) 30% of the generic Net CONE value will not be repriced, since these offers (a) are likely to be consistent with a competitive offer level and (b) can at worst suppress prices by 20 to 30 percent.

b. *Price impact threshold.* If some capacity offers were repriced, but the effect of repricing those offers is not large, then the RPM will clear with the offers as submitted. If each LSE simply covered its net short position through ownership or contracts, the total quantity of resources would be approximately what was needed, IRM+1, plus or minus some amount reflecting differing views on load growth, lumpy project investment, etc. Even if all these resources were offered in at $0, the RPM would clear near the IRM+1 target quantity and a corresponding price near Net CONE. The MOPR's price impact threshold allows natural fluctuations around Net CONE, only restoring a price nearer Net CONE if a large price effect was induced by the actions of a party that stood to profit from the excursion.

18. The MOPR also includes a "sunset" provision that triggers when new resources are required in the Rest of Market area. At such time, the price differential between historically constrained zones and the rest of market will be small, with the pool-wide clearing price at or near Net CONE in most years. When that occurs, the benefit to suppressing the price inside the LDA is also small. The Settlement Agreement does provide, however, that if the Net CONE in some LDA exceeds the Net CONE in surrounding areas by 50 percent or more, that the MOPR would apply to that high-cost LDA. This provision ensures that differences in prices driven by underlying cost differences are not erased.

19. To the greatest extent possible, the MOPR was designed to be a symmetric check on the bids from new entry. Although, as a general matter, bids from new entry should be competitive, the Settlement Agreement identifies possible situations where bids that, if left in the market, would unduly shift (up or down) the capacity clearing price from its competitive level. Bids that are above a competitive level and not checked by sufficient competition from other new entry bids can be rejected, avoiding market price distortions. The MOPR provides a parallel check on bids that are below a competitive level. The MOPR strikes an equitable balance of leaving these offers in the market, thereby giving the contracting parties the benefit of the particular contract, while neutralizing large price distortions created by purchases well in excess of forecast reliability needs.

20. This concludes my affidavit.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	Docket No. EL05-148-000 Docket No. ER05-1410-000

AFFIDAVIT OF ROBERT B. STODDARD

Commonwealth of Massachusetts
ss.
Suffolk County

I, Robert B. Stoddard, being duly sworn, depose and state that the contents of the foregoing Affidavit dated September 28, 2006, is correct, accurate and complete to the best of my knowledge, information, and belief:

Robert B. Stoddard

SUBSCRIBED AND SWORN to
before me this 28th day of September, 2006

Suzanne M. Walsh
Notary Public
My commission expires: 2/26/2011

SUZANNE M. WALSH
Notary Public
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires
February 26, 2011

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Attachment F
RPM Timeline

RPM Timetable

Date	Item
4 months before BRA	Data Submittal to MMU for Preliminary Market Structure Screen (MSS)

3 months before BRA	• Post results of Preliminary MSS
	• Post Parameters for Delivery Year (DY)
	    o Preliminary PJM Region/Zonal Peak Load Forecasts and ILR Forecasts by LDA
	    o IRM, Pool-wide Average EFORd, and FPR
	    o Demand Resource Factor
	    o PJM Region Reliability Requirement and VRR Curve for PJM Region
	    o LDA Reliability Requirements and VRR Curves for the LDAs to be modeled in BRA (including the CETO and CETL information)
	    o Transmission Upgrades expected to be in service for DY
	    o CONE and Net E&AS values used in VRR Curves

2 months before BRA	• Data Submittal to MMU if submitting non-zero sell offer price for a resource in an LDA or Unconstrained LDA Group that fails Preliminary MSS • Election of FRR Alternative starting with DY
1 month before DY BRA	• MMU to notify Capacity Market Sellers of Market Seller Offer Caps • Submittal of Initial FRR Capacity Plan for Delivery Year
DY – 3 years (May)	DY Base Residual Auction (BRA)
DY – 23 months (June)	DY First Incremental Auction
DY – 12 months (Feb 28)	Post Final PJM Region/Zonal Peak Load Forecasts for DY
DY – 13 months (April)	DY Second Incremental Auction
DY – 6 months (Nov 30)	Final EFORd fixed for DY
DY – 4 months (January)	DY Third Incremental Auction
DY – 3 months (March 1)	ILR Nomination
June 1, DY	Start of Delivery Year (DY)

RPM Timetable

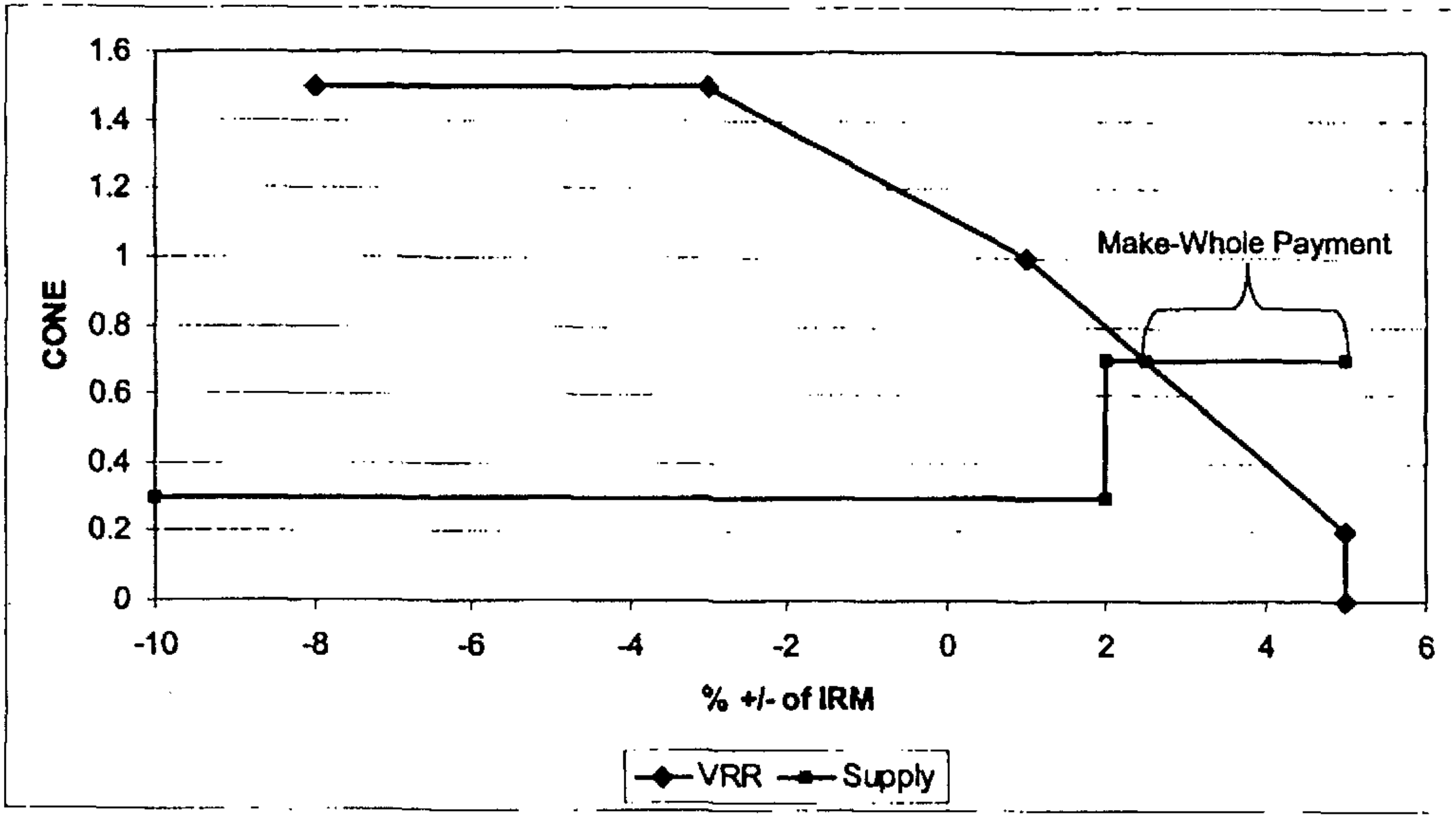
RPM Timetable Example for 2011/2012 Delivery Year

Date	Item
January 2008	*Data Submittal to MMU for Preliminary Market Structure Screen (MSS)*
February 1, 2008	• Post results of Preliminary MSS • Post Parameters for 2011/2012 Delivery Year (DY) o Preliminary PJM Region/Zonal Peak Load Forecasts and ILR Forecasts by LDA o IRM, Pool-wide Average EFORd, and FPR o Demand Resource Factor o *PJM Region Reliability Requirement and VRR Curve for PJM Region* o LDA Reliability Requirements and VRR Curves for the LDAs to be modeled in BRA (including *the CETO and CETL information)* o Transmission Upgrades expected to be in service for 2011/2012 DY o CONE and Net E&AS values used in VRR *Curves*
March 2008	• Data Submittal to MMU if submitting non-zero sell offer price for a resource in an LDA or Unconstrained LDA Group that fails Preliminary MSS • *Election of FRR Alternative starting with 2011/2012 DY*
April 2008	• MMU to notify Capacity Market Sellers of Market Seller Offer Caps • Submittal of Initial FRR Capacity Plan for 2011/2012 Delivery Year
May 2008	2011/2012 DY Base Residual Auction
June 2009	2011/2012 DY First Incremental Auction
February 28, 2010	Post Final PJM Region/Zonal Peak Load Forecasts for 2011/2012 DY
April 2010	2011/2012 DY Second Incremental Auction
November 30, 2011	Final EFORd fixed for 2011/2012 DY
January 2011	2011/2012 DY Third Incremental Auction
March 1, 2011	ILR Nomination
June 1, 2011	Start of 2011/2012 Delivery Year

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

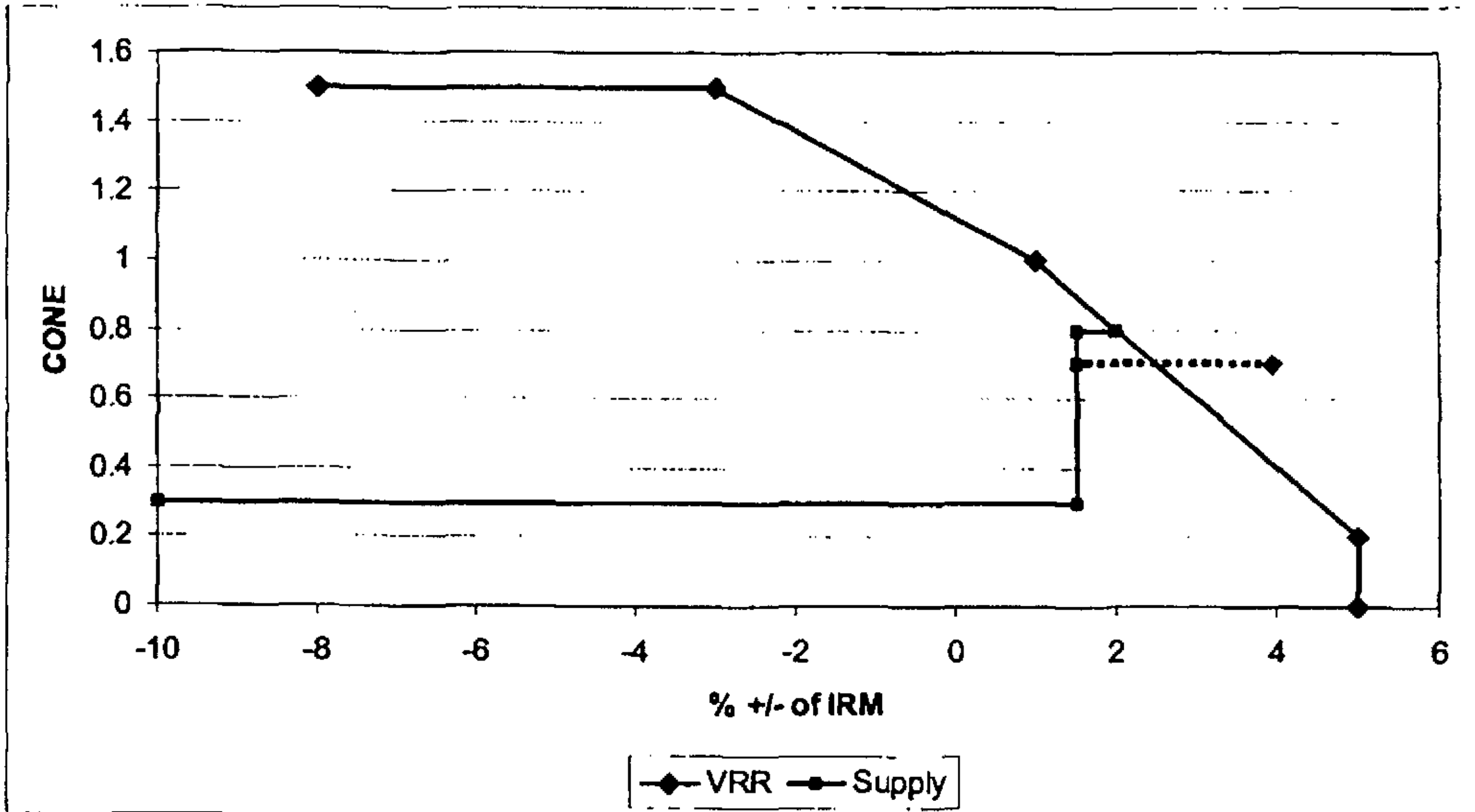
Attachment G
Illustration of
Auction Clearing Scenarios

Make-Whole Example



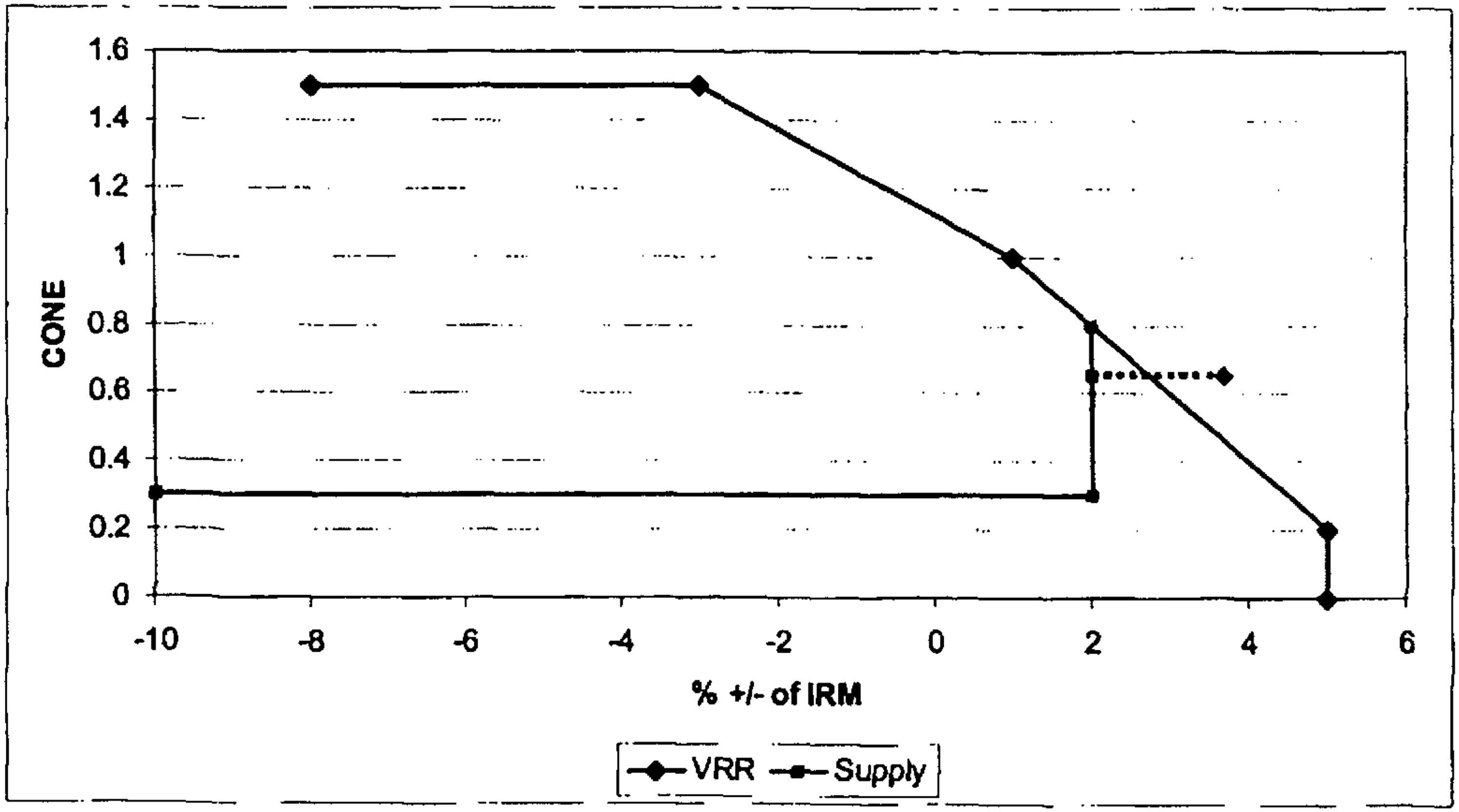
- All Offers are Block Bid
- Since Optimization only needs to clear portion of last offer, VRR sets clearing price
- Clearing Price is 0.7 CONE at IRM+2.5%
- Make Whole payments are for the MW portion of block bid beyond VRR curve

Substitution Example



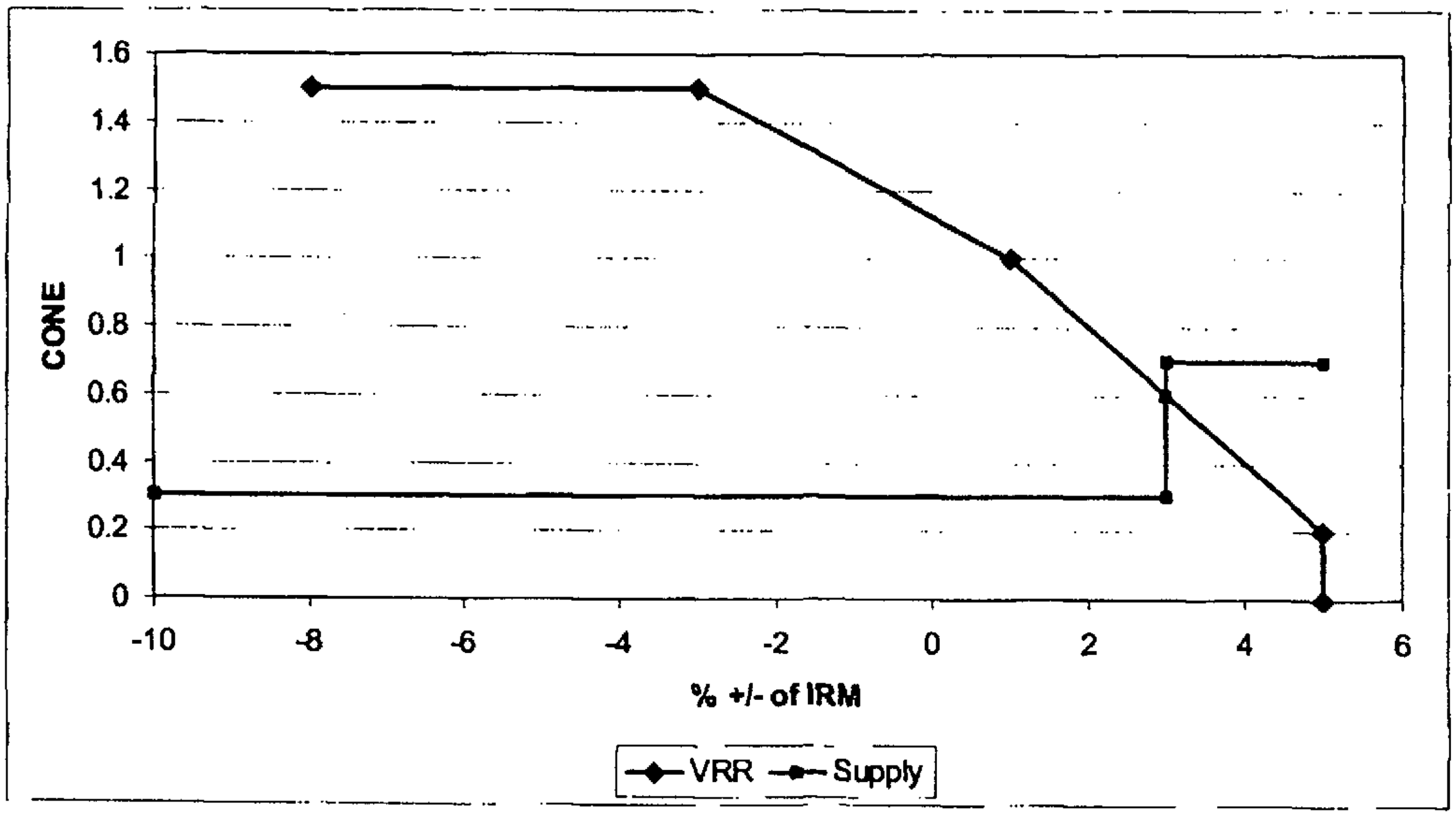
- All Offers are Block Bid
- Optimization will clear the lowest overall cost to LDA
- Substitutes the higher priced offer in for the lower priced offer with no flexibility
- Clearing Price is 0.8 CONE at IRM+2%
- Offer with dotted line does not clear because of lack of flexibility
- No Make Whole payments

Supply Curve Extension Example



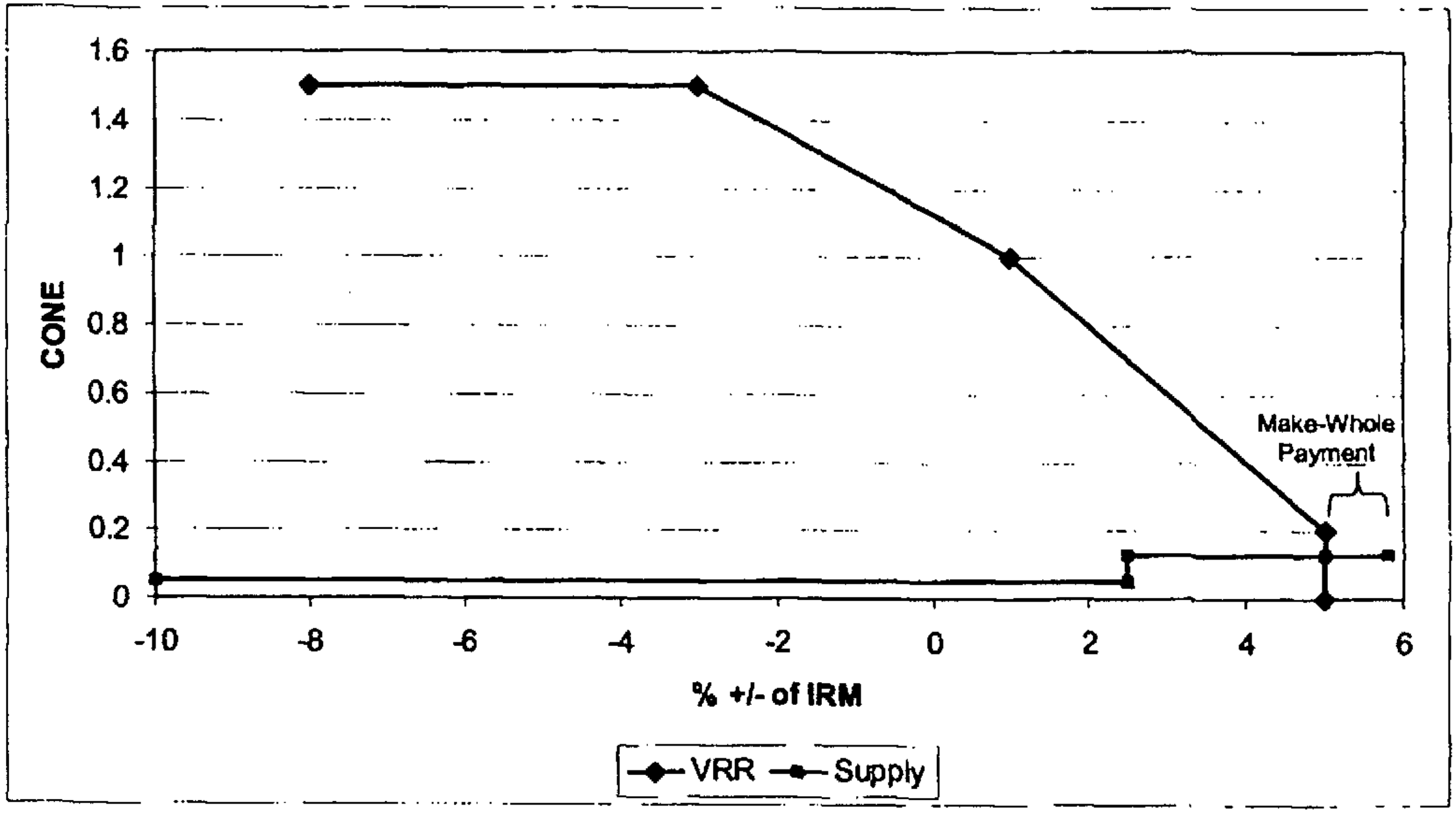
- All Offers are Block Bid
- Continuing vertical portion of supply curve to intersection of VRR Curve results in lower overall cost to LDA
- Since intersection occurs at vertical portion of **Supply** curve, VRR sets clearing price
- Clearing Price is 0.8 CONE at IRM+2%
- Offer with dotted line does not clear because of lack of flexibility
- No Make Whole payments

No Make-Whole Example



- All Offers are Block Bid
- Since intersection occurs at vertical portion of **Supply** curve, VRR sets clearing price
- Clearing Price is 0.6 CONE at IRM+3%
- No Make Whole payments

Vertical VRR Example



- All Offers are Block Bid
- Since intersection occurs at vertical portion of **VRR** curve, Supply sets clearing price
- Clearing Price is 0.13 CONE at IRM+5%
- Make Whole payments are for the MW portion of block bid beyond VRR curve

PJM Interconnection, L.L.C.
Docket Nos. EL05-148 and
ER05-1410
September 29, 2006

Tab 2
Settlement Agreement
And
Attachments

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket Nos.	ER05-1410-000 and -001
	)		EL05-148-000 and -001

SETTLEMENT AGREEMENT
AND OFFER OF SETTLEMENT

TABLE OF CONTENTS

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

PJM Interconnection, L.L.C.	)	Docket Nos.	ER05-1410-000 and -001
	)		EL05-148-000 and -001

SETTLEMENT AGREEMENT AND OFFER OF SETTLEMENT

Pursuant to Rule 602 of the Federal Energy Regulatory Commission's ("Commission" or "FERC") Rules of Practice and Procedure, this Settlement Agreement and Offer of Settlement (collectively "Settlement Agreement") is submitted by the following parties (and certain of their members or affiliates, as listed in the Settlement Agreement) in this proceeding: Allegheny Electric Cooperative, Inc., Allegheny Energy Companies, American Electric Power, American Forest and Paper Association, Blue Ridge Power Agency, Con Edison Energy, Constellation Energy Group Inc., Dayton Power & Light Co., Dominion Resources Services, Inc., Duke Energy North America, LLC, Edison Mission Energy, Exelon Corporation, FirstEnergy Service Co., FPL Energy Generators, Indiana Office of Utility Consumer Counsel, Indiana Utility Regulatory Commission, Kentucky Public Service Commission, Liberty Electric Power, LLC, LS Power Associates, LP, Michigan Public Service Commission, Mirant Energy Trading, L.L.C., North Carolina Electric Membership Corporation, Old Dominion Electric Cooperative, Pennsylvania Office of Consumer Advocate, PEPCO Holdings, Inc., PJM Industrial Customer Coalition, PJM Interconnection, L.L.C., Portland Cement Association, Reliant Energy Inc., Southern Maryland Electric Cooperative, Inc., Virginia

Municipal Electric Association, and Williams Power Company, Inc. (collectively "Settling Parties").

This Settlement Agreement resolves all issues in Docket Nos. ER05-1410-000 and -001, and EL05-148-000 and -001.

I. BACKGROUND

On August 31, 2005, PJM Interconnection, L.L.C. filed under sections 205 and 206 of the Federal Power Act ('FPA") a proposal for a reliability pricing model ("RPM") to replace its existing capacity obligation rules ("August 31st Filing"). In the August 31st Filing, PJM asked the Commission to find that its existing capacity construct is unjust and unreasonable and that its RPM proposal was a just and reasonable replacement.[1]

On April 20, 2006, the Commission issued an Initial Order on RPM.[2] In its order, the Commission found that PJM's existing capacity construct is unjust and unreasonable.[3] In addition, the Commission made a number of findings as to various aspects of the RPM proposal.[4] In addition to these findings, the Commission instituted a paper hearing and scheduled a technical conference to address a number of issues for which the Commission sought additional information.[5]

Pursuant to the April 20 Order, on May 19, 2006, PJM filed a brief on the paper hearing issues. Parties to the proceeding filed comments on PJM's brief on June 2, 2006, and reply comments on June 16, 2006. The technical conference required by the April 20

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1 *August 31st Filing* at 3.

2 *PJM Interconnection, L.L.C.*, 115 FERC ¶ 61,079 (2006) ("April 20 Order").

3 *Id.* at P 1.

4 *Id.* at P 6.

5 *Id.* at P 173.

Order was held on June 7-8, 2006. Comments on the technical conference were filed on June 22, 2006.

On May 8, 2006, the American Forest and Paper Association ("AFPA") filed a motion to establish settlement judge proceedings, and requested that Administrative Law Judge Lawrence Brenner conduct those proceedings.[6] AFPA also requested that the Commission suspend the technical conference and paper hearing procedures established in the April 20 Order pending the outcome of the proposed settlement judge proceedings.[7] On May 17, 2006, the Commission issued an Order Granting Motion for Appointment of Settlement Judge and Denying Request to Suspend Scheduled Proceedings.[8] In that order, the Commission established settlement judge procedures, but denied AFPA's request to suspend the procedural schedule during the course of the settlement judge proceedings.[9] In addition, the Commission granted AFPA's request that the scope of the settlement discussions would not be limited to the issues that the Commission ordered to be the subject of the paper hearing and technical conference.[10]

Beginning on June 5, 2006, and continuing through the end of July, the parties to this proceeding engaged in lengthy and intense settlement discussions. As noted in the August 3, 2006 Report By Settlement Judge On Agreement In Principle issued in this proceeding, over 150 individuals representing more than 65 parties engaged in more than

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6 A number of parties either supported or did not oppose the motion to establish settlement judge proceedings.

7 *See* AFPA Motion at 1.

8 115 FERC ¶ 61,186 (2006).

9 *Id.* at P 1.

10 *Id.* at P 5.

25 days of settlement discussions with direct Settlement Judge involvement and with the assistance of Mr. Steven Shapiro of the Dispute Resolution Service, and numerous other meetings among the negotiating parties during the settlement period. On August 2, the parties voted on an agreement in principle embodied in a settlement term sheet. All of the parties to this Settlement Agreement either voted to support or not oppose the settlement term sheet. Six parties to the proceeding voted to oppose the settlement term sheet.[11]

Throughout the months of August and September, the parties either supporting or not opposing settlement engaged in further negotiations to resolve the open issues and specifics necessary to reach final settlement on all issues in the term sheet. In addition, the parties drafted and finalized this Settlement Agreement, the accompanying PJM Tariff sheets, and necessary changes to the Reliability Assurance Agreement ("RAA").

II. SETTLEMENT AGREEMENT

A. Implementation Date

The RPM construct described herein shall replace PJM's current capacity construct beginning on June 1, 2007.

B. Variable Resource Requirement Curve

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[11] The parties that opposed the settlement term sheet were: Catoctin Power, LLC, Coral Power LLC, Maryland Office of the People's Counsel, New Jersey Board of Public Utilities, PPL Parties, and the PSEG Companies, consisting of Public Service Electric and Gas Company, PSEG Energy Resources & Trade LLC and PSEG Power LLC.

The RPM capacity auctions shall be cleared using a Variable Resource Requirement Curve[12] ("VRR Curve") as outlined in the August 31st Filing, at section 5.10 of the proposed attachment to the PJM Tariff setting forth the RPM terms and conditions.[13] The Settling Parties have agreed to modify the parameters of the VRR Curve as described below, and depicted in the accompanying graph. All Cost of New Entry ("CONE") values described and depicted in this section are computed on an unforced equivalent basis as defined in Section 5.10 of Attachment DD.

1. The price is 1.5 times the difference between the CONE and the Net Energy and Ancillary Services Revenue Offset ("Net CONE"), when the quantity is less than or equal to three percentage points less than the approved PJM Region Installed Reserve Margin ("IRM");

2. The VRR Curve then follows a straight line to a price equal to Net CONE, when the quantity is one percentage point greater than the approved PJM Region IRM;

3. The VRR Curve then follows a straight line to a price equal to 0.2 times Net CONE, when the quantity is five percentage points greater than the approved PJM Region IRM; and

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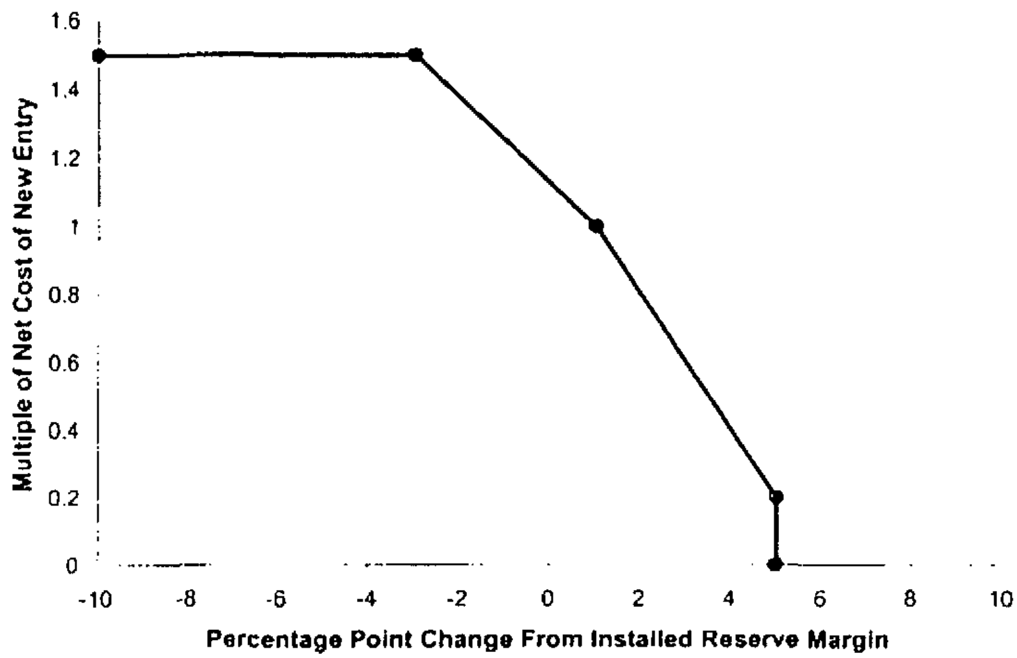
12 Capitalized terms used in this Settlement Agreement that are not otherwise defined in this Settlement Agreement have the meaning given in the PJM Tariff or Reliability Assurance Agreement.

13 That PJM Tariff attachment was designated as "Attachment Y" in the August 31st Filing ("Original Attachment Y"). The attachment is now designated as "Attachment DD" to the PJM Tariff.

4. The VRR Curve then falls vertically to a price of zero at a reserve level, which is five percentage points greater than the approved PJM Region IRM.



C. **Base Residual Auction**

PJM will conduct a Base Residual Auction ("BRA") as outlined in Section 5.4 of Original Attachment Y, except that, after the Transition Period, the forward commitment shall be three years, not four years, before the Delivery Year. For example, the BRA for the Delivery Year beginning June 2011 will be held in May 2008.

D. **Incremental Auctions**

Subsequent to the BRA and prior to the Delivery Year, PJM will conduct three Incremental Auctions, as proposed in Original Attachment Y § 5.4, to provide a mechanism for market participants to commit additional resources that may be needed for the Delivery Year either to replace previously committed resources that have become unavailable or to accommodate an increase in the forecasted load.

E. Commitment Period

As proposed in the August 31st Filing, as modified herein, the commitment period for the capacity being offered in the BRA is one year, beginning on June 1 and continuing through May 31 of the following calendar year ("Delivery Year").

F. Reliability Backstop

The Settlement retains Section 16 of Original Attachment Y, except that Section 16.3(a)(i) shall provide that, rather than being triggered after four consecutive years, the Reliability Backstop will be triggered "if the total Unforced Capacity of all Capacity Resources committed through Self-Supply or the Base Residual Auctions for three consecutive Delivery Years...." (emphasis added).

G. Auction Clearing

1. Annual Pricing

This Settlement Agreement eliminates the seasonal aspect to capacity pricing proposed in the August 31st Filing. Therefore, the optimization algorithm utilized in the BRA shall minimize the cost of committing Capacity Resources for the entire Delivery Year.

2. Optimization to Minimize LDA Cost

This Settlement clarifies Section 5.12 of Original Attachment Y to ensure that PJM minimizes total PJM Region capacity costs, regardless of whether the quantity clearing the BRA is above or below the applicable target quantity, by providing that the optimization algorithm will select from among multiple possible alternative clearing results that satisfy applicable constraints and requirements. Such alternatives include, for example, accepting a lower-priced Sell Offer that intersects the VRR Curve and that specifies a minimum capacity block, accepting a higher-priced Sell Offer that intersects the VRR 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 VRR Curve that corresponds to the Unforced Capacity provided by all Sell Offers located entirely below the VRR Curve. Section 5.12 shall also be modified to add Section 5.12(e), entitled Equal-Priced Sell Offers, to address the situation where two or more Sell Offers would result in the same total costs to the market under the algorithm.

H. System Constraints

1. Phase-in of LDAs for RPM Pricing Purposes

This Settlement Agreement retains a transition to the full number of Locational Deliverability Areas ("LDAs"), but modifies the phase-in approach.[14] Specifically, under this Settlement Agreement, the LDA transition shall be as follows:

- For Delivery Year 2007/2008: 4 LDAs- SW MAAC (PEPCO and BG&E), Eastern MAAC (PSE&G, JCP&L, PECO, AE, DPL, RECO), MAAC Region plus APS (SW MAAC, Eastern MAAC, Penelec, Met Ed, PPL, and APS), and Rest of Market ("ROM") (ComEd, AEP, Dayton, Dominion, and Duquesne);
- For Delivery Year 2008/2009: same 4 LDAs;
- For Delivery Year 2009/2010: same 4 LDAs; and
- For Delivery Year 2010/2011 and forward: 23 LDAs proposed by PJM in the August 31st Filing.

During this Transition Period, PJM shall post, for informational purposes only, prices for each of the 23 LDAs (i.e., assuming no LDA phase-in) for each BRA.

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[14] The LDA phase-in described herein is intended to apply for RPM pricing purposes and is not intended to apply for purposes of the Regional Transmission Expansion Plan ("RTEP").

2. Identification of Transmission Constraints for Pricing Purposes

As part of the process to determine pricing for each LDA, PJM will determine and post the Capacity Emergency Transfer Objective ("CETO") and Capacity Emergency Transfer Limit ("CETL") values for all LDAs. If an LDA potentially would be constrained, PJM shall determine and post the separate VRR Curve and separate VRR Curve data (e.g., LDA Reliability Requirement, projected ILR, applicable CONE, and applicable Net CONE) for the LDA. Thus, there will be a potential for price separation for that LDA. To be clear, because the BRA shall clear using the actual resource offers in each of the LDAs, some of the LDAs may not bind in terms of a price separation.

Consistent with the phase-in of LDAs as discussed above, PJM will establish a separate VRR Curve for an LDA whenever the CETL is less than 105% of the CETO of the LDA, unless PJM determines that an acceptable level of reliability, consistent with the Reliability Principles and Standards, requires establishment of a separate VRR Curve for an LDA with a margin greater than 5%. In such a case, PJM will post on its web site before February 1, the LDA for which the VRR Curve is being established and the margin or other information that is being used rather than the 5% margin.

3. Integration with Regional Transmission Expansion Planning Process

The manner in which the Capacity Resources will be integrated with the Regional Transmission Expansion Planning ("RTEP") process shall be clarified. First, Generation Capacity Resources that do not clear in the BRAs, and are not sold elsewhere ("At Risk Generation"), shall be considered the minimum amount of at risk generation in the market efficiency analysis of the RTEP process and be considered at risk in the sensitivity cases in the RTEP market efficiency analysis. If necessary, PJM shall file to amend Schedule 6 of the PJM Operating Agreement to ensure such treatment of "at risk" generation. Second, the PJM planning market efficiency analysis shall take into account energy congestion and locational capacity prices, differentials in the initial cost-benefit determination of proposed transmission solutions, and later cost-benefit analyses.

4. LDAs for Pricing Purposes - Definitions and Process

a. Creation of New LDAs for RPM Pricing Purposes

If a new LDA is included in the PJM RTEP planning process, PJM will make a filing to create under RPM, a new LDA (including a new aggregate LDA) if such new region is projected to have a CETL less than 105% of CETO or to address other reliability concerns discussed above. In addition, market participants may propose, and PJM will evaluate, new LDAs (including new aggregate LDAs) for inclusion in the RTEP planning process and RPM.

b. Posting Unconstrained LDAs

In order to ensure that market participants have relevant information prior to the conduct of a BRA, PJM will identify on its website prior to the BRA the LDAs that do not have the potential to bind because they are not constrained LDAs.

c. Process to Change LDAs for RPM Pricing Purposes

The Settling Parties agree that in order for PJM to change any of the LDAs, either during the transition or in the end state, PJM shall make a filing under Section 205 of the FPA to effectuate such a change.

5. Transfer of Obligations to Pay Locational Reliability Charges

Original Attachment Y shall be modified to provide that for purposes of PJM settlements and billing processes, obligations to pay Locational Reliability Charges can be transferred between and among LSEs and other Market Participants as follows: PJM shall facilitate a process, similar to eSchedules, whereby before or after any BRA, an LSE or other Market Participant can provide PJM with a schedule that specifies the buyer, seller, volume of capacity to be transferred, location where capacity prices are calculated, and start and end date of that transfer. This PJM-facilitated process shall not alter the physical supply and demand balance in the BRA, and such transfers shall not establish any obligations that are incompatible with the BRA or any other auction.

I. *Market Power Mitigation*

All mitigation shall be as proposed by PJM in the August 31st Filing and PJM's May 19, 2006 Brief on Paper Hearing Issues (at pages 25-38), except as follows:

1. Market Power Mitigation Rules for Planned Generation Capacity Resources

Section 6.5(a)(ii) of Original Attachment Y shall be amended to provide that offers based on Planned Generation Capacity Resources shall be presumed competitive in the auctions for the first Delivery Year for which such resource qualifies as a Planned Generation Capacity Resource, but may be rejected if found by the PJM Market Monitoring Unit not to be competitive in accordance with certain specified criteria and procedures.

Planned Generation Capacity Resources that clear the BRA shall be treated as Existing Generation Capacity Resources in the auctions for any subsequent Delivery Year; provided, however, that such resources may receive certain price assurances for the two Delivery Years immediately following the first Delivery Year of service under the conditions specified in Section II.K of this Agreement.

Section 6.5(a)(ii) further shall provide that Sell Offers based on Planned Generation Capacity Resources submitted for the first year in which such resources qualify as Planned Generation Capacity Resources shall be deemed competitive and not be subject to mitigation if: (1) collectively all such Sell Offers provide Unforced Capacity in an amount equal to or greater than two times the incremental quantity of new entry required to meet the LDA Reliability Requirement; and (2) at least two unaffiliated suppliers have submitted Sell Offers for Planned Generation Capacity Resources in such LDA. Notwithstanding the foregoing, any Capacity Market Seller, together with Affiliates, whose Sell Offers based on Planned Generation Capacity Resources in that LDA are pivotal is subject to mitigation.

Where these first two conditions are not met or the Sell Offer is pivotal, the Market Monitoring Unit shall: (1) compare each such Sell Offer to Sell Offers submitted in other LDAs (with due recognition for locational differences) and to the Cost of New Entry for the LDA in which the offer otherwise would clear and other LDAs (with due recognition for locational differences); (2) evaluate potential barriers to new entry on the basis of interviews with potential suppliers and other market participants; and (3) determine, based on that analysis, whether to reject such Sell Offer as non-competitive. Following the conduct of the applicable auction and before the final determination of clearing prices, in accordance with the same timeframe for possible cost-capping of offers based on existing resources, the Market Monitoring Unit shall notify a seller whose Sell Offer is deemed non-competitive and allow such Capacity Market Seller an opportunity to submit a revised Sell Offer. PJM then shall clear the auction with such revised Sell Offer in place if the Market Monitoring Unit determines that such revised offer is competitive in accordance with the above criteria. If the revised Sell Offer is not deemed competitive, it will be rejected.

2. Modifications and Clarifications to Avoidable Cost Formula

The Avoidable Cost Rate contained in Section 6.8(a) of Original Attachment Y shall be modified and clarified as follows:

- **APIR (Avoidable Project Recovery Rate) = PI * CRF**

Where:

- **PI** is the amount of project investment reasonably required to enable a Generation Capacity Resource that is the subject of a Sell Offer to continue operating or improve availability during Peak-Hour Periods during the Delivery Year.

- **CRF** is the annual capital recovery factor from the following table applied in accordance with the terms specified below.

Age of Existing Unit (in Years)	Remaining Life of Plant (Years)	Levelized CRF
1 to 5	20	0.125
6 to 10	15	0.146
11 to 15	10	0.198
16 Plus	5	0.363
Mandatory Capital Expenditures ("CapEx")	4	0.450
40 Plus Alternative	1	1.100

Unless otherwise stated, Age of Existing Unit shall be equal to the number of years since the Unit commenced commercial operation, up to and through the relevant Delivery Year.

Remaining Life of Plant defines the amortization schedule (*i.e.*, the maximum number of years over which the Project Investment may be included in the Avoidable Cost Rate.)

Capital Expenditures and Project Investment

For any given Project Investment, a Capacity Market Seller may make a one-time election to recover such investment using: (i) the highest CRF and associated recovery schedule to which it is entitled; or (ii) the next highest CRF and associated recovery schedule. For these purposes, the CRF and recovery schedule for the "16 Plus" category is the next highest CRF and recovery schedule for both the "Mandatory CapEx" and the "40 Plus Alternative" categories. The Capacity Market Seller using the above table must provide the PJM Market Monitoring Unit with information, identifying and supporting such election, including but not limited to the age of the unit, the amount of the Project Investment, the purpose of the investment, evidence of corporate commitment (e.g., an SEC filing, a press release, or a letter from a duly authorized corporate officer indicating intent to make such investment), and detailed information concerning the governmental requirement (if applicable). Absent other written notification, such election shall be deemed based on the CRF such Seller employs for the first Sell Offer reflecting recovery of any portion of such Project Investment. A Sell Offer submitted in the BRA for either or both of the 2007-2008 and 2008-2009 Delivery Years for which the "16 Plus" CRF and recovery schedule is selected may not exceed an offer price equal to the then-current Net CONE (on an unforced-equivalent basis).

For any resource using the CRF and associated recovery schedule from the CRF table that set the Capacity Resource Clearing Price in any Delivery Year, such Capacity Market Seller must also provide to the PJM Market Monitoring Unit, for informational purposes only, evidence of the actual expenditure of the Project Investment, when such information becomes available.

If the project associated with a Project Investment that was included in a Sell Offer using a CRF and associated recovery schedule from the above table has not entered into commercial operation prior to the end of the relevant Delivery Year, and the resource's Sell Offer sets the clearing price for the relevant LDA, the Capacity Market Seller shall be required to elect to either (i) pay a charge that is equal to the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR component of the Avoidable Cost Rate, this difference to be multiplied by the cleared MW volume from such Resource ("rebate payment"); (ii) hold such rebate payment in escrow, to be released to the Capacity Market Seller in the event that the project enters into commercial operation during the subsequent Delivery Year or rebated to LSEs in the relevant LDA if the project has not entered into commercial operation during the subsequent Delivery Year; or (iii) make a reasonable investment in the amount of the PI in other existing Generation Capacity Resources owned or controlled by the Capacity Market Seller or its Affiliates in the relevant LDA. The revenue from such rebate payments shall be allocated pro rata to LSEs in the relevant LDA(s) that were charged a Locational Reliability Charge for such Delivery Year, based on their Daily Unforced Capacity Obligation in the relevant LDA(s). If the Sell Offer from the Generation Capacity Resource did not set the Capacity Resource Clearing Price in the relevant LDA, no alternative investment or rebate payment is required. If the difference between the Capacity Resource Clearing Price for such LDA for the relevant Delivery Year and what the clearing price would have been absent the APIR amount does not exceed the greater of $10 per MW-day or a 10% increase in the clearing price, no alternative investment or rebate payment is required.

Mandatory CapEx Option

The Mandatory CapEx CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), to a resource that must make a Project Investment to comply with a governmental requirement that would otherwise materially impact operating levels during the Delivery Year, where: (i) such resource is a coal, oil or gas-fired resource that began commercial operation no fewer than fifteen years prior to the start of the first Delivery Year for which such recovery is sought, and such Project Investment is equal to or exceeds $200/kW of capitalized project cost; or (ii) such resource is a coal-fired resource located in an LDA for which a separate VRR Curve has been established for the relevant Delivery Years, began commercial operation at least 50 years prior to the effective date of that certain September 29, 2006 Settlement Agreement in FERC Docket Nos. ER05-1410 and EL05-148, and the Capacity Market Seller submitting the sell offer for such resource was a signatory or an Affiliate of a signatory to such Settlement Agreement.

A Capacity Market Seller that wishes to elect the Mandatory CapEx option for a Project Investment must do so beginning with the Base Residual Auction for the Delivery Year in which such project is expected to enter commercial operation. A Sell Offer submitted in any Base Residual Auction for which the "Mandatory CapEx" option is selected may not exceed an offer price equivalent to 0.90 times the then-current Net CONE (on an unforced-equivalent basis).

40 Year Plus Alternative Option

The 40 Plus Alternative CRF and recovery schedule is an option available, beginning in the third BRA (Delivery Year 2009-10), for a resource that is a gas- or oil-fired resource that began commercial operation no less than 40 years prior to the conduct of the relevant BRA (excluding, however, any resource in any Delivery Year for which the resource is receiving a payment under Part V of the PJM Tariff). Generation Capacity Resources electing this 40 Plus Alternative CRF shall be treated as At Risk Generation for purposes of the sensitivity runs in the RTEP process. Resources electing the 40 Year Plus Option will be modeled in the RTEP process as "at-risk" at the end of the one-year amortization period.

A Capacity Market Seller that wishes to elect the 40 Plus Alternative option for a Project Investment must provide written notice of such election to the Office of the Interconnection no later than six months prior to the Base Residual Auction for which such election is sought; provided however that shorter notice may be provided if unforeseen circumstances give rise to the need to make such election and such seller gives notice as soon as practicable.

The Office of the Interconnection shall give market participants reasonable notice of such election, subject to satisfaction of requirements under the PJM Operating Agreement for protection of confidential and commercially sensitive information. A Sell Offer submitted in any Base Residual Auction for which the "40 Plus

Alternative" option is selected may not exceed an offer price equivalent to the then-current Net CONE (on an unforced-equivalent basis).

Section 6.8(b) of Original Attachment Y is modified as follows:

(b) For the purpose of determining an Avoidable Cost Rate, avoidable expenses are incremental expenses directly required to operate a Generation Capacity Resource that a Generation Capacity Resource Owner would not incur if such Resource did not operate during the Delivery Year or meet Availability criteria during Peak-Hour Periods during the Delivery Year.

In addition, Section 6.7 of the Original Attachment Y is modified to provide, in connection with the Capacity Market Seller's submittal of data and calculations for the Market Seller Offer Cap for each existing generation resource that the Market Monitoring Unit shall "notify the Capacity Market Seller one month prior to the auction whether such submittal will be accepted, and if not, provide to such seller detailed information as to why such submittal was not accepted."

3. Relaxed Information Requirement Conditions

The Settling Parties have agreed to delete 6.7(a)(ii) of Original Attachment Y. In addition, the Settling Parties have agreed to make non-substantive modifications to Section 6.7(b) to conform with the Settlement described herein. The Settlement Agreement also includes a new Section 6.7(c) that provides as follows:

(c) Potential auction participants identified in subsection (b) above need not submit the data specified in that subsection for any Generation Capacity Resource:

i. that is in an Unconstrained LDA Group or, if this is the relevant market, the entire PJM Region, and is in a resource class determined by the Market Monitoring Unit as not likely to include the marginal price-setting resources in such auction; or

ii. for which the potential participant commits that any Sell Offer it submits as to such resource shall not include any price above the level identified for the relevant resource class by the Market Monitoring Unit.

> The Market Monitoring Unit shall determine, in its discretion, following stakeholder consultation, the resource classes and corresponding prices described in this subsection and shall identify such resource classes and prices in the posting required by section 6.2(a). Nothing herein precludes the Market Monitoring Unit from requesting additional information from any potential auction participant as deemed necessary by the Market Monitoring Unit, including, without limitation, additional cost data on resources in a class that is not otherwise expected to include the marginal price setting resource; and compliance with such request shall be a condition of participation in any auction. Any Sell Offer submitted in any auction that is inconsistent with any commitment made pursuant to this subsection shall be rejected, and the Capacity Market Seller shall be required promptly to resubmit a Sell Offer that complies with such commitments. If the Capacity Market Seller does not timely resubmit its Sell Offer, it shall be deemed to have submitted a Sell Offer that complies with the commitments made under this subsection, with a default price equal to the maximum price for the class of resource identified in the Sell Offer, as previously specified by the Market Monitoring Unit in the posting required by section 6.2(a). Notwithstanding the foregoing, if the Capacity Market Seller demonstrates to the satisfaction of the Market Monitoring Unit that a significant change in circumstances warrants submission of a Sell Offer that is inconsistent with a prior commitment under this subsection, then the Market Monitoring Unit shall allow such Sell Offer provided that the Capacity Market Seller promptly notifies the Market Monitoring Unit upon becoming aware of the change in circumstances and provides all information deemed necessary by the Market Monitoring Unit to support such Sell Offer and that the offer is otherwise consistent with the requirements of this section 6. The obligation imposed under section 6.6(a) shall not be satisfied unless and until the Capacity Market Seller submits (or is deemed to have submitted) a Sell Offer that conforms to its commitments made pursuant to this subsection.

Finally, the Settling Parties have agreed to replace Section 6.7(d)(iv) with the following:

> (iv) Projected PJM Market Revenues, as defined by section 6.8(d) for any Generation Capacity Resource to which the Avoidable Cost Rate is applied.

4. Offer Cap Offset

The Settling Parties have agreed to set forth the energy and ancillary services offset to the Offer Cap in a new section to Original Attachment Y. Specifically, the Settling Parties have agreed to a new provision, Section 6.8(d), which provides that:

> (d) Projected PJM Market Revenues for any Generation Capacity Resource to which the Avoidable Cost Rate is applied shall include all actual unit-specific revenues from PJM energy markets, ancillary services, and unit-

specific bilateral contracts from such Generation Capacity Resource, net of marginal costs for providing such energy (i.e., costs allowed under cost-based offers pursuant to Section 6.4 of Schedule 1 of the Operating Agreement) and ancillary services from such resource.

(i) For the first three BRAs (for Delivery Years 2007-08, 2008-09, 2009-10), the calculation of Projected PJM Market Revenues shall be equal to the simple average of such net revenues as described above for calendar years 2001-2006; and

(ii) For the fourth BRA (delivery year 2010-11) and thereafter, the calculation of Projected PJM Market Revenues shall be equal to the rolling simple average of such net revenues as described above from the three most recent whole calendar years prior to the year in which the BRA is conducted.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because the Generation Capacity Resource was not integrated into PJM during the full period, then the Projected PJM Market Revenues shall be calculated using only those whole calendar years within the full period in which such Resource received PJM market revenues.

If a Generation Capacity Resource did not receive PJM market revenues during the entire relevant time period because it was not in commercial operation during the entire period, then the Projected PJM Market Revenues shall be calculated based upon net revenues received over the entire period by comparable units, to be developed by the MMU and the Capacity Market Seller.

5. Market Power Mitigation During the Transition Period

A new section 17.5, entitled "Market Mitigation During Transition Period" will be added to Original Attachment Y. New section 17.5 will provide as follows:

The provisions of Section 6 of this Attachment shall apply to all Reliability Pricing Model Auctions conducted during the Transition Period; provided, however, that during the Transition Period, as to a Capacity Market Seller that was a signatory to that certain Settlement Agreement dated September 29, 2006 in FERC Docket Nos. ER05-1410 and ER05-148, or any Affiliate of such a signatory, and that owns or controls no more than 10,000 megawatts of Unforced Capacity in the PJM Region, the otherwise applicable Market Seller Offer Cap provided in Section 6 shall be increased by up to the following amounts in the following years for any Sell Offer submitted by such a seller in any Unconstrained LDA Group with respect to no more than 3,000 megawatts of such Unforced Capacity:

(a) $10/MW-day for the 2007-2008 Delivery Year;

(b) $10/MW-day for the 2008-2009 Delivery Year; and

(c) $7.50/MW-day for the 2009-2010 Delivery Year;

For purposes of this provision, the 10,000 megawatt maximum shall apply separately to a Capacity Market Seller's resources subject to state rate-based regulation and resources that are not subject to state rate-based regulation.

J. Minimum Offer Price Rule for New Entry in Constrained LDAs

A new Section 5.14(h) shall be added to Original Attachment Y of the PJM Tariff, providing as follows:

(1) Prior to each Base Residual Auction, the Market Monitoring Unit shall develop locational asset-class estimates of competitive, cost-based, real levelized (year one) Cost of New Entry, net of energy and ancillary service revenues ("Net Asset Class Cost of New Entry"). Other than the levelization approach, determination of the Cost of New Entry component of the Net Asset Class Cost of New Entry shall be consistent with the methodology used to determine the Cost of New Entry set forth in Section 5.10(a)(iv)(A) of this Attachment. Notwithstanding the foregoing, the Net Asset Class Cost of New Entry shall be zero for: (i) base load resources, such as nuclear, coal and Integrated Gasification Combined Cycle, that require a period for development greater than three years; (ii) any facility associated with the production of hydroelectric power; (iii) any upgrade or addition to an existing Generation Capacity Resource; or (iv) any Planned Generation Capacity Resource being developed in response to a state regulatory or legislative mandate to resolve a projected capacity shortfall in the Delivery Year affecting that state, as determined pursuant to a state evidentiary proceeding that includes due notice, PJM participation, and an opportunity to be heard.

(2) The Market Monitoring Unit shall evaluate any Sell Offer that is based on a Planned Generation Capacity Resource submitted in a Base Residual Auction for the first Delivery Year in which such resource qualifies as such a resource, in any LDA for which a separate VRR Curve has been established, and shall determine whether such Sell Offer meets each of the following criteria:

i. Sell Offer affects the Clearing Price;

ii. Sell Offer is less than 80 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry, less than 70 percent of the Net Asset Class

Cost of New Entry for the Reference Resource effective in such LDA; and

iii. The Capacity Market Seller and any Affiliates has or have a "net short position" in such Base Residual Auction for such LDA that equals or exceeds (a) ten percent of the LDA Reliability Requirement, if less than 10,000 megawatts, or (b) five percent of the total LDA Reliability Requirement, if equal to or greater than 10,000 megawatts. A "net short position" shall be calculated as the actual retail load obligation minus the portfolio of supply. An "actual retail load obligation" shall mean the LSE's combined load served in the LDA at or around the time of the Base Residual Auction adjusted to account for load growth up to the Delivery Year, using the Forecast Pool Requirement. A "portfolio of supply" shall mean the Generation Capacity Resources (on an unforced capacity basis) owned by the Capacity Market Seller and any Affiliates at the time of the Base Residual Auction plus or minus any generation that is, at the time of the BRA, under contract for the Delivery Year.

(3) If the Market Monitoring Unit determines that all of the criteria of Section 5.14(h)(2) are met, it shall notify the Capacity Market Seller of this determination. Within five business days, or such other period to which the Market Monitoring Unit consents, such Capacity Market Seller may supply the Market Monitoring Unit with specific information about the costs and operational parameters relating to its Sell Offer. If the Capacity Market Seller fails to supply any such information within the specified time, or if the Market Monitoring Unit determines that the information provided, combined with revenues that would be earned in PJM-administered markets as determined by PJM, does not support the offer, the applicable cost-based net Cost of New Entry determined in Section 5.14(h)(1) shall be used to establish an alternative Sell Offer. The alternative Sell Offer employed in place of the actual Sell Offer shall be equal to 90 percent of the applicable Net Asset Class Cost of New Entry or, if there is no applicable Net Asset Class Cost of New Entry equal to 80 percent of the Net Asset Class Cost of New Entry for the Reference Resource. Upon timely receipt of such information, the Market Monitoring Unit shall determine whether such Sell Offer is consistent with the real levelized(year one) competitive, cost-based, fixed, net cost of new entry were the resource to rely solely on revenues from PJM-administered markets (i.e., were all output from the unit sold in PJM-administered spot markets). The Market Monitoring Unit shall adjust the alternative Sell Offer if appropriate on the basis of the relevant and reliable supporting information available and the application of an objective analysis.

(4) The Market Monitoring Unit shall request that the Office of the Interconnection perform a sensitivity analysis on any Base Residual

Auction that included Sell Offers meeting the criteria of Section 5.14(h)(2), for which an acceptable alternative Sell Offer was not provided consistent with Section 5.14(h)(3). Such analysis shall re-calculate the clearing price for the Base Residual Auction employing in place of each actual Sell Offer meeting the criteria a substitute Sell Offer equal to 90 percent of the applicable estimated cost determined in accordance with Section 5.14(h)(1) above, or, if there is no applicable estimated cost, equal to 80 percent of the then-applicable Net CONE. If the resulting difference in price between the new clearing price and the initial clearing price differs by an amount greater than the greater of 20 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 15,000 megawatts; or the greater of 25 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement greater than 5,000 and less than 15,000 megawatts; or the greater of 30 percent or 25 dollars per megawatt-day for a total LDA Reliability Requirement of less than 5,000 megawatts; then the Market Monitoring Unit shall discard the results of the Base Residual Auction and determine a replacement clearing price and the identity of the accepted Capacity Resources using the procedure set forth in section 5.14(h)(5) below.

(5) Including all of the Sell Offers in a single Base Residual Auction that meet the criteria of 5.14(h)(4) above, PJM shall first calculate the replacement clearing price and the total quantity of Capacity Resources needed for the LDA. PJM shall then accept Sell Offers to provide Capacity Resources in accordance with the following priority and criteria for allocation: (i) first, all Sell Offers in their entirety designated as self-supply; (ii) then, all Sell Offers of zero, prorating to the extent necessary, and (iii) then all remaining Sell Offers in order of the lowest price, subject to the optimization principles set forth in Section 5.14.

(6) Notwithstanding the foregoing, this provision shall terminate when there exists a positive net demand for new resources, as defined in Section 5.10(a)(iv)(B) of this Attachment, calculated over a period of consecutive Delivery Years beginning with the first Delivery Year for which this Attachment is effective and concluding with the last Delivery Year preceding such calculation, in an area comprised of the Unconstrained LDA Group in existence during such first Delivery Year. Notwithstanding the foregoing, the Market Monitoring Unit shall reinstate the provisions of this section, solely under conditions in which a constrained LDA has a gross Cost of New Entry equal to or greater than 150 percent of the greatest prevailing gross Cost of New Entry in any adjacent LDA.

The Settling Parties agree that, in addition to the Article V provision regarding No Admissions or Precedent, contained in this Settlement Agreement, this Section J is not intended to reflect any position of the Settling Parties regarding the appropriate level of offer price for new capacity resources in a residual auction.

K. New Entry Price Adjustment

This Agreement establishes a New Entry Price Adjustment in the PJM Tariff and addresses PJM Market Monitoring Unit review of such New Entry Price Adjustment.

1. New section 5.14(c)

The Settling Parties have added a new Section 5.14(c) to Attachment DD in order to address a New Entry Price Adjustment. The new provision states as follows:

> 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:
>
> i. 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;
>
> ii. Acceptance of such Sell Offer in such BRA increases the total Unforced Capacity in the LDA in which such Resource will be located from a megawatt quantity below the LDA Reliability Requirement to a megawatt quantity corresponding to a point on the VRR Curve where price is no greater than 0.40 times the applicable Net CONE divided by (one minus the pool-wide average $EFOR_D$); and
>
> iii. 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 equal to the lesser of: 1) the price in such seller's Sell Offer for the BRA in which such resource qualified as a Planned Generation Capacity Resource; or 2) 0.90 times the then-current Net CONE, on an Unforced Capacity basis, for such LDA.
>
> If the Sell Offer is submitted consistent with the foregoing conditions, then:
>
> i. in the first Delivery Year, the Resource sets the Capacity Resource Clearing Price for the LDA and all resources in the LDA receive the Capacity Resource Clearing Price.

ii. in the subsequent two BRAs, if the Resource clears, it shall receive the higher of the foregoing Sell Offer price and the Capacity Resource Clearing Price for such LDA. If the Sell Offer price exceeds the Capacity Resource Clearing Price, the difference will be paid 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).

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.

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.

2. Market Monitor Review

The MMU's existing authority and review responsibilities will include the New Entry Price Adjustment. The MMU shall analyze and include New Entry Price Adjustment in the State of the Market Report.

L. Determination of the Cost of New Entry

1. CONE for First Four Delivery Years

Subject to Article III of this Agreement, the CONE used to establish the VRR Curves for the BRA for the first, second, third, and fourth Delivery Years (i.e., the Delivery Years commencing June 1, 2007, June 1, 2008, June 1, 2009, and June 1, 2010) shall be at the levels provided in section 5.10(a)(iii) of Original Attachment Y, offset by the Energy and Ancillary Services Revenue offsets determined in accordance with section II.M of this Agreement. The CONE and the Energy and Ancillary Services Revenue Offset shall continue to be separately calculated for any subsequent Delivery Years, and determined in accordance with the provisions of this Agreement and the PJM Tariff.

2. Procedures for Possible Automatic Adjustment to the Cost of New Entry for the Fifth and Subsequent Delivery Years

The CONE established by Section II.L.1 of this Agreement is subject to automatic adjustment under certain conditions. The procedures, conditions, and standards governing such automatic adjustments shall be set forth in a new subsection to section 5.10 of Attachment DD, providing as follows:

(B) Following the Transition Period, the CONE shall be subject to adjustment in accordance with the following:

(1) The CONE in a CONE Area shall be evaluated for possible adjustment when there is a Net Demand for New Resources in the Base Residual Auctions over a period of three consecutive Delivery Years.

(2) Net Demand for New Resources means that, for any such three-year period evaluated, the following formula yields a positive number:

FPR Adjusted Load Growth in Years 1 to 3 + Generation Retirements in Years 1 to 3 –Surplus Resources in Year 1 + (CETL in Year 3 CETL in Year 1);

where:

FPR Adjusted Load Growth in Years 1 to 3 – (Preliminary Zonal Peak Load Forecast for all Zones in such CONE Area for the third Delivery Year in such evaluation minus the Preliminary Zonal Peak Load Forecast for such Zones for the Delivery Year immediately preceding the three Delivery Years evaluated) times the Forecast Pool Requirement (substituting in such calculation, however, a percentage figure of IRM+1, rather than IRM);

Generation Retirements in Years 1 to 3 = all announced deactivations, pursuant to Part V of the PJM Tariff, of Existing Generation Capacity Resources in such CONE Area with an effective date of any day during the three consecutive Delivery Years evaluated, stated on an Unforced Capacity basis;

Surplus Resources in Year 1 = the total Unforced Capacity of all existing Generation Capacity Resources located in such CONE Area that are subject to the offer requirement in section 6.6 of this Attachment for the first Delivery Year evaluated, less the total Unforced Capacity corresponding to "Point Two" (as defined in section 5.10(a)(i)) on the Variable Resource Requirement Curves for all LDAs in such CONE Area for such Delivery Year.

CETL = Capacity Emergency Transfer Limit to the area for which there is a separate VRR curve.

(3) For each CONE Area for which there is a Net Demand for New Resources over such three-year period, as determined pursuant to subsection (b) above, the CONE shall be adjusted (if at all) as prescribed by subsection (e) to the extent required based on the quantity of Unforced Capacity cleared in the Base Residual Auction, as set forth in subsection (d).

(4) If a CONE Area encompasses areas with separate VRR Curves, then the procedures described in subsections (d) and (e) below will be applied separately for each area with a separate VRR Curve, and the CONE for the CONE Area will be determined as the average of the resulting CONE value for the areas, the average to be weighted by the LDA Reliability Requirement of each area. If, pursuant to subsection (f) below, a CONE Area that had been composed of areas with separate VRR Curves is divided into multiple CONE Areas, then the CONE for each new CONE Area will be reset based on the historical CONE values computed for that area, not the weighted average of the now-defunct CONE Area.

(5) If the quantity of Unforced Capacity cleared in the Base Residual Auction for the third Delivery Year evaluated is:

(i) in the Equilibrium Zone, no change to CONE is required.

(ii) above the Equilibrium Zone, CONE shall be decreased in accordance with subsection (e); provided, however, that no change to CONE is required if the excess of Unforced Capacity relative to the Equilibrium Zone for the third Delivery Year evaluated is less than or equal to the excess of Unforced Capacity relative to the Equilibrium Zone for the first Delivery Year evaluated.

(iii) below the Equilibrium Zone, CONE shall be increased in accordance with subsection (e); provided, however, if CONE was increased as a result of Unforced Capacity clearing below the Equilibrium Zone in a CONE adjustment evaluation hereunder for such CONE Area for the immediately preceding Delivery Year, then CONE shall be increased only if the shortage of Unforced Capacity relative to the Equilibrium Zone for the third Delivery Year evaluated is greater than or equal to the shortage of Unforced Capacity relative to the Equilibrium Zone for the first Delivery Year evaluated.

(6) In any case where an increase or decrease to CONE in a CONE Area is required by the above provisions:

(i) the then-current value of the Cost of New Entry for such CONE Area shall be compared against the Empirical CONE for such area,

where:

Empirical CONE = the weighted average for all LDAs in the CONE Area (weighted by load in such LDAs) of: (i) the average Capacity Resource Clearing Price in each such LDA determined in the Base Residual Auctions for such three Delivery Years; plus (ii) the average of the Net Energy and Ancillary Market Revenue Offsets used in the Variable Resource Requirement Curve for such LDA for such three years.

(ii) if an increase is required, CONE shall be increased by the lesser of (a) 0.50 times the positive difference between Empirical CONE and CONE; and (b) 0.10 times CONE.

where a decrease is required, CONE shall be decreased by the lesser of (a) 0.50 times the negative difference between Empirical CONE and CONE; and (b) 0.10 times CONE.

(7) Any LDA for which a separate VRR Curve has been established for the Base Residual Auctions for each of three consecutive Delivery Years shall be evaluated under the provisions of this section. If the result of such evaluation is that the CONE calculated for such LDA would differ by at least 10 percent from the CONE then applicable to such LDA, then such LDA shall be established as a CONE Area, with a Cost of New Entry adjusted based on the Cost of New Entry computed over the prior three Delivery Years for that LDA.

ADDITIONAL DEFINITIONS FOR DEFINITION SECTION

"Equilibrium Zone" shall mean:

(a) for the VRR Curve for the PJM Region, any quantity of Unforced Capacity between (i) [the PJM Region Reliability Requirement multiplied by (100% plus IRM%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation; and (ii) [the PJM Region Reliability Requirement multiplied by (100% plus IRM% plus 2%) divided by (100% plus IRM%)] minus the Forecast RTO ILR Obligation; and

(b) for the VRR Curve for any Locational Deliverability Area, any quantity of Unforced Capacity between (i) [the LDA Reliability Requirement multiplied by (100% plus IRM%) divided by (100% plus IRM%)] minus the Forecast LDA ILR Obligation; and (ii) [the LDA Reliability Requirement multiplied by (100% plus IRM% plus 2%) divided by (100% plus IRM%)] minus the Forecast LDA ILR Obligation (if not previously accounted for in establishing the CETO for such LDA);

where:

"Forecast LDA ILR Obligation" – the sum of the Forecast Zonal ILR Obligations for all Zones in such LDA.

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

M. Net Energy and Ancillary Services Revenue Offset to the Cost of New Entry Used to Establish the VRR Curve

The Net Energy and Ancillary Services Revenue Offset used to determine the VRR Curves in the BRA for the first, second, and third Delivery Years (i.e., the Delivery Years beginning on June 1, 2007, June 1, 2008, and June 1, 2009) shall be determined as proposed in section 5.10(a)(iv) to Original Attachment Y. However, the Settlement Agreement amends that subsection to provide that:

- energy revenues will be calculated on the basis of Peak-Hour Dispatch, as described herein, using Real-Time Prices;
- the Reference Resource definition in Attachment DD used as the basis of this calculation shall be revised to state that it is based on the same specific resource used in the August 31st Filing to estimate the CONE;
- the heat rate of such resource shall be 10,500 MMBtu/MWhs;
- the calculation of the Net Energy and Ancillary Services Revenue Offset for sub-regions of the PJM Region pursuant to section 5.10(a) of Attachment DD, shall use a posted fuel pricing point in such sub-region, if available, and if such pricing point is not available, a fuel transmission adder to such sub-region from an appropriate pricing point for the PJM Region; and
- if such sub-region, for which a separate CONE was calculated, 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.

For purposes of the Base Residual Auction for any Delivery Year following the first three Delivery Years, the Energy and Ancillary Services Revenue Offset shall be calculated in the same manner as set forth in this section, except that the calculation shall be based on the three consecutive calendar years preceding such calculation.

Peak-Hour Dispatch, for purposes of calculating the Net Energy and Ancillary Services Revenue Offset for the Reference Resource prescribed above, will be defined in Attachment DD as an assumption that the Reference Resource is dispatched 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 real-time LMP for the area for which the Net CONE 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 dispatched 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 dispatched for such block. The details of such calculation will be posted in the PJM Manuals.

N. Deficiency Charges

1. Ability to Cure

The charges and credits proposed in the Sections 7-13 of Original Attachment Y shall apply. Provided, however, that a Capacity Market Seller that fails or is expected to fail a rating test under Section 7 may obtain and commit Unforced Capacity from a replacement Generation Capacity Resource meeting the same locational requirements.

Any such commitment shall be effective upon no less than one day's notice to the Office of the Interconnection. Such Unforced Capacity may include uncommitted/uncleared Sell Offer blocks from Generation Capacity Resources that were otherwise committed. The charge shall be assessed from the first day of the season for which the test was failed through the last day before the effective date of the commitment of such replacement Generation Capacity Resource in an amount equal to the full shortage of Unforced Capacity determined in Section 7.1(b) of Attachment DD. Thereafter, any charges assessed on the Capacity Market Seller that fails such a rating test under Section 7 shall be assessed for such full shortage of Unforced Capacity less any amount from such replacement Generation Capacity Resource.

2. Peak Hour Period Availability

The Settling Parties agree to add a new Section 10 to Attachment DD that provides for peak hour availability charges and credits. The new Section 10 will provide as follows:

(a) To preserve and maintain the reliability of the PJM Region and to encourage Capacity Market Sellers to maintain the availability of Generation Capacity Resources during critical peak hours of the Delivery Year, each Capacity Market Seller that commits a Generation Capacity Resource for a Delivery Year shall be credited or charged to the extent the critical peak-period availability of its committed Generation Capacity Resources exceeds or falls short, respectively, of the expected availability of such resources. Charges and credits hereunder shall not apply to wind or solar resources.

(b) Critical peak periods for purposes of this assessment ("Peak-Hour Periods") shall be the hour ending 1500 EPT through the hour ending 1900 EPT on any day during the calendar months of June through August that is not a Saturday, Sunday, or federal holiday, and the hour ending 800 EPT through the hour ending 900 EPT and the hour ending 1900 EPT through the hour ending 2000 EPT on any day during the calendar months of January and February that is not a Saturday, Sunday or federal holiday.

(c) Peak-Period Equivalent Forced Outage Rate and Peak-Period Capacity Calculations

The Peak-Period Equivalent Forced Outage Rate shall be calculated for Peak-Hour Periods based on the following formula:

$EFOR_P$ (%) = (FOH + EFPOH) / (SH + FOH)

where

FOH = full forced outage hours when the unit was called upon, excluding those outages deemed as OMC (as defined below);

EFPOH = equivalent forced partial outage hours when the unit was called upon, excluding those outages deemed as OMC (as defined below); and

SH = service hours as defined pursuant to NERC GADS standards.

The Peak-Period Capacity of a Generation Capacity Resource shall be calculated as follows:

PCAP = ICAP * (1.0 - $EFOR_P$)

where

ICAP = the installed capacity rating of such Generation Capacity Resource

(d) Determination of Expected $EFOR_P$ and PCAP for Generation Capacity Resources: For each Delivery Year, the expected $EFOR_P$ and PCAP of each Generation Capacity Resource committed to serve load in such Delivery Year shall be the $EFOR_P$ and UCAP, respectively, calculated on a rolling-average basis using such resource's service history during the five consecutive annual periods of twelve consecutive months ending September 30 last preceding such Delivery Year. Such $EFOR_D$ and UCAP shall be determined in accordance with Schedule 5 of the Reliability Assurance Agreement, which excludes (for purposes of Capacity Resource UCAP calculations) outages deemed outside management control in accordance with the standards and guidelines of NERC ("Outside Plant Management Control" or "OMC") as defined in the Generating Availability Data System, Data Reporting Instructions in Attachment K or its successor.

(e) For each Delivery Year, the actual $EFOR_P$ and PCAP of each Generation Capacity Resource shall be calculated during the Peak-Hour Periods of such Delivery Year, provided however, that such calculation shall not include any day such a resource was unavailable if such unavailability resulted in a charge or penalty due to delay, cancellation, retirement, de-rating, or rating test failure. The full or partial forced outage hours when called upon shall be those outage hours during which the cost-based offer for energy from the resource would have been less than the applicable Locational Marginal Price for such resource, or when the Office of the Interconnection would have called upon the resource (absent the outage) for operating reserves, in both cases as determined by the Office of the Interconnection in accordance with the procedures specified in the PJM Manuals (including, without limitation, respecting such unit's current operating constraints). In addition, for single-fueled, natural gas-fired units, a failure to perform during the winter Peak-Hour Period shall be excused for purposes of this section if the Capacity Market Seller can demonstrate to the Office of the Interconnection that such failure was due to non-availability of gas to supply the unit.

(f) If the calculation under subsection (e) for any Generation Capacity Resource for a Delivery Year results in fewer than fifty total Service Hours during Peak Hour Periods, then the actual $EFOR_P$ for purposes of such calculation shall be the resource's $EFOR_D$ and the actual PCAP for purposes of such calculation shall be the resource's UCAP, in both cases considering all hours in the Delivery Year (to the extent required by the $EFOR_D$ and UCAP calculations).

(g) For each Delivery Year, the excess or shortfall in Peak-Hour Period availability for each Generation Capacity Resource shall be determined by comparing such resource's expected and actual PCAP, subject to the limitation under subsection (h) below. The net Peak-Hour Period availability shortfall or excess for each Capacity Market Seller and FRR Entity in each Locational Deliverability Area, shall be the net of the shortfalls and excesses of all Generation Capacity Resources in such Locational Deliverability Area committed by such Capacity Market Seller for such Delivery Year.

(h) As to any Generation Capacity Resource experiencing or expected to experience a full or partial outage during any Peak-Hour Period that would or could result in a shortfall under subsection (g) above, a Capacity Market Seller may obtain and commit Unforced Capacity from a replacement Generation Capacity Resource (not previously committed) meeting the same locational requirements as such resource. Such Unforced Capacity shall be recognized for purposes of this section prospectively from the effective date of commitment of such replacement resource, and to the extent such replacement Unforced Capacity thereafter is available during Peak-Hour Periods, any shortfall that otherwise would have been calculated shall be reduced to that extent. Any such commitment of replacement capacity shall be effective upon no less than one day's notice to the Office of the Interconnection.

(i) The shortfall determined for any Generation Capacity Resource shall not exceed an amount equal to 0.50 times the Unforced Capacity of such resource; provided, however, that if such limitation is triggered as to any

Generation Capacity Resource for a Delivery Year, then the decimal multiplier for this calculation as to such resource in the immediately succeeding Delivery Year shall be increased to 0.75, and if such limitation again is triggered in such succeeding Delivery Year, then the multiplier shall be increased to 1.00. The multiplier shall remain at such elevated level for each succeeding Delivery Year until the shortfall experienced by such resource is less than 0.50 times the Unforced Capacity of such resource for three consecutive Delivery Years.

(j) A Peak-Hour Period Availability Charge shall be assessed on each Capacity Market Seller with a net shortfall in PCAP in an LDA, where such charge is equal to such shortfall times the annual Capacity Clearing Price determined for such Locational Deliverability Area for such Delivery Year (365* the clearing price expressed in $/MW-day).

(k) The revenues from such charges shall be distributed to the Capacity Market Sellers, and FRR Entities that committed Generation Capacity Resources, in such Locational Deliverability Area that have net excess PCAP for such Delivery Year, provided however that any such seller shall be paid no more than the product of such seller's net excess PCAP times the Capacity Resource Clearing Price determined for such Locational Deliverability Area for such Delivery Year. Any excess revenues remaining after such distribution shall be distributed to all LSEs in the Zone that were charged the same Locational Reliability Charge for the Delivery Year for which the Peak Hour Availability Charge was assessed, and to all FRR Entities in the Zone that are LSEs and whose FRR Capacity Plan resources over-performed in the Delivery Year, on a pro-rata basis in accordance with each LSE's Daily Unforced Capacity Obligation.

(l) The Office of the Interconnection shall provide estimated charges and credits based on the summer Peak-Hour Periods within three calendar months after the end of the summer period. Final charges and credits for the Delivery Year shall be billed within three calendar months following the end of the winter period.

By June 1, 2007, PJM will analyze the historical availability of gas supplies in the PJM Region during winter conditions and its impact on the ability of generators to deliver capacity and to otherwise affect their reliability of performance. PJM shall, to the extent that such analysis indicates is necessary, develop adequate performance metrics within the PJM Manuals and propose any necessary changes to Section 10(e) of Attachment DD. Pending the outcome of the above study and acceptance by FERC of the resulting FPA

Section 205 filing by PJM, the following, as set forth in new section 10(e) above, shall apply: For single fueled natural gas-fired units, a failure to perform during the winter $EFOR_P$ period shall be excused for purposes of the $EFOR_P$ performance metric if Seller can demonstrate to the OI that such failure was due to non-availability of gas to supply the unit.

O. Fixed Resource Requirement

The long-term Fixed Resource Requirement Alternative ("FRR Alternative") proposed by PJM in its August 31st Filing shall be revised as provided below. The FRR Alternative discussed herein provides an alternative means to RPM for an eligible LSE to satisfy its Unforced Capacity Obligation for loads in the PJM Region. The FRR Alternative applies only to the ability of an FRR Entity to meet its Unforced Capacity Obligation and does not affect the ability of an FRR Entity to participate in all other voluntary markets administered by PJM. Terms used in this Section II.O are as defined in the PJM RAA.

1. Eligibility

An investor-owned utility ("IOU"), Electric Cooperative, or Public Power Entity, as defined in the RAA, shall be eligible to select the FRR Alternative if it demonstrates the capability to satisfy the entire Unforced Capacity obligation for all load, including load growth, in the applicable FRR Service Area for the term of such entity's participation in the FRR Alternative.

Eligible entities that select the FRR Alternative must designate all load, including load growth, in the PJM Region.

However, an FRR Entity may split its loads between RPM and the FRR Alternative if: (1) the Party elects the FRR Alternative for all load (including expected load growth) in one or more FRR Service Areas; (2) the Party complies with the rules and procedures of the Office of the Interconnection and all relevant Electric Distributors related to the metering and reporting of load data and settlement of accounts for separate FRR Service Areas; and (3) the Party separately allocates its Capacity Resources to and among FRR Service Areas in accordance with rules specified in the PJM Manuals. The Office of the Interconnection shall use sub-accounts for Parties meeting these conditions, to facilitate implementation of these provisions.

In addition to the eligibility requirements of Paragraph 1 above, a Single-Customer LSE may select the FRR Alternative, provided that: (a) the Single-Customer LSE is a signatory to this Settlement Agreement (or is an entity that (i) is a named member of an association or coalition that is a signatory to the Settlement Agreement, and (ii) does not file or join in any comments opposing this Settlement Agreement); (b) the Single-Customer LSE selects the FRR Alternative on or before April 1, 2008; (c) the Single-Customer LSE meets the requirements of Section B.3. of Schedule 8.1 to the PJM RAA; and (d) the aggregate total of such selections does not exceed 1000 MW of Obligation Peak Load in the PJM Region.

2. Election, and Termination of Election, of the FRR Alternative

An entity eligible for the FRR Alternative must make its initial selection of the FRR Alternative option no less than two months before the conduct of the BRA for the first Delivery Year for which such election is to be effective. Such notice must be provided in writing to the Office of the Interconnection and the minimum duration of the FRR Alternative selection is five consecutive Delivery Years.

An FRR Entity may terminate its election of the FRR Alternative effective with the commencement of any Delivery Year following the minimum five Delivery Year commitment by providing written notice of such termination to PJM no later than two months prior to the BRA for such Delivery Year. An FRR Entity that has terminated its election of the FRR Alternative shall not be eligible to re-elect the FRR Alternative for a period of five consecutive Delivery Years following the effective date of such termination.

Notwithstanding Sections B.1. and B.2. above, in the event of a State Regulatory Structural Change, as defined in Section 1.81 of the RAA, the affected FRR Entity may either elect the FRR Alternative or terminate its election of the FRR Alternative effective as to any Delivery Year by providing written notice of such election or termination to PJM as soon as possible but in any event no later than two (2) months prior to the BRA for such Delivery Year.

No later than one month prior to the deadline for entities to select the FRR Alternative, PJM shall post on its website the percentage of Capacity Resources required to be located in each LDA.

3. FRR Capacity Plan and FRR Commitment Insufficiency Charge

No later than one month before the initial BRA after FRR selection, each FRR Entity shall submit its FRR Capacity Plan to PJM demonstrating its commitment of Capacity Resources for the term of such election sufficient to meet the FRR Entity's Daily Unforced Capacity Obligation for the load identified in the FRR Capacity Plan. Each FRR Entity shall extend and update such plan by no later than one month prior to the BRA *for each succeeding* Delivery Year.

Each FRR Capacity Plan shall indicate the nature and current status of each resource, including the status of each planned Generation or Demand Response resource, the planned deactivation or retirement of any such resource, and the status of commitments for each sale or purchase of capacity included in the FRR Capacity Plan.

The FRR Capacity Plan of any FRR Entity that commits, for any Delivery Year, not to sell surplus Capacity Resources as a Capacity Market Seller in the RPM auctions, either directly or indirectly, shall designate Capacity Resources in an amount (MW) 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. Those FRR Entities that do not commit, for any Delivery Year, to not sell surplus Capacity Resources as a Capacity Market Seller in the RPM auctions, either directly or indirectly, shall designate Capacity Resources at least equal to the Threshold Quantity, as defined in Section 1.82 and Schedule 8.1 to the PJM RAA. The Threshold Quantity cannot be sold into the RPM auctions, but can be used to meet the FRR Entity's load growth or be sold to an entity outside of PJM or to another FRR Entity.

All Capacity Resources committed in an FRR Capacity Plan shall meet the applicable Capacity Resource requirements pursuant to the RAA and the PJM Operating Agreement and must be on a unit-specific basis. Capacity Resources that are subject to bilateral contract(s) for less than a full Delivery Year may be committed in an FRR Capacity Plan if the resources included in such plan in the aggregate satisfy all obligations for all Delivery Years.

All load management programs on which an FRR Entity intends to rely for a Delivery Year must be included in the FRR Capacity Plan and satisfy all requirements applicable to Demand Resources. However, previously uncommitted Unforced Capacity from such load management programs may be used to satisfy an increased capacity obligation of an FRR Entity.

For each LDA for which PJM establishes a separate VRR Curve for any Delivery Year addressed by a Capacity Resource Plan, the plan must include a minimum percentage of Capacity Resources for such Delivery Year located within such LDA ("Percentage Internal Resources Required"). Such Percentage Internal Resources Required shall be calculated as provided in Section D.5. of Schedule 8.1 to the PJM RAA. An FRR Entity may reduce its Percentage Internal Resources Required for an LDA by committing to a Qualified Transmission Upgrade, as set forth in Attachment DD to the PJM Tariff, that increases the CETL for such LDA.

PJM shall assess the adequacy of all FRR Capacity Plans. If PJM determines that an FRR Capacity Plan submitted by an entity seeking to elect the FRR Alternative does not satisfy the Party's capacity obligations, the entity shall not be permitted to elect the FRR Alternative.

If a previously approved FRR Entity submits an FRR Capacity Plan that is not sufficient, 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 the FRR Entity shall be assessed an FRR Commitment Insufficiency Charge. The amount of this charge shall be equal to two times the CONE for the relevant location, times the shortfall of Capacity Resources below the FRR Entity's capacity obligation, including any Threshold Quantity requirement, for the remaining term of the plan.

4. Conditions on Purchases and Sales of Capacity Resources by FRR Entities

An FRR Entity may not include in its FRR Capacity Plan for any Delivery Year any Capacity Resource that has cleared in any RPM auction for such Delivery Year. An FRR Entity may include in its FRR Capacity Plan Capacity Resources obtained from another FRR Entity, provided, however, that each FRR Entity is responsible for meeting its own capacity obligations and that the same megawatts of Unforced Capacity shall not be committed to more than one FRR Capacity Plan for any given Delivery Year.

An FRR Entity that designates Capacity Resources in its FRR Capacity Plan for a Delivery Year based upon a Threshold Quantity may offer to sell Capacity Resources in excess of that needed for the Threshold Quantity in an RPM auction, provided, however, that such sales must not exceed an amount equal to the lesser of (a) 25% times the Unforced Capacity equivalent of the IRM for such Delivery Year times the Preliminary Forecast Peak Load for which the FRR Entity is responsible under its plan for such Delivery Year, or (b) 1300 MW.

An FRR Entity that designates Capacity Resources in its FRR Capacity Plan for a Delivery Year based upon a Threshold Quantity may not offer to sell such resources in any RPM auction, but may use such resources to meet any increased capacity obligation due to unanticipated load growth, or may sell such resources outside the PJM region or to another FRR Entity, subject to Section D of Schedule 8.1 of the RAA.

An entity that selects the FRR Alternative for only part of its load in the PJM Region that designates Capacity Resources as Self-Supply in an RPM auction to meet its expected Daily Unforced Capacity Obligation shall not be required, solely due to such designation, to identify Capacity Resources in its FRR Capacity Plan based on the Threshold Quantity. However, such entity may not designate Capacity Resources in excess of the lesser of (a) 25% times the entity's total Unforced Capacity Obligation or

(b) 200 MW. An entity can avoid this limitation by identifying Capacity Resources in its FRR Capacity Plan based on the Threshold Quantity.

5. FRR Daily Unforced Capacity Obligations and Deficiency Charges

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 provided in Section F of Schedule 8.1 to the RAA.

An FRR Entity shall be assessed an FRR Capacity Deficiency Charge in each Zone addressed in the 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 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 twice the Cost of New Entry applicable to such Zone.

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 Schedule 8.1 to the RAA.

6. Capacity Resource Performance

Any Capacity Resource committed by an FRR Entity in an FRR Capacity Plan for a Delivery Year shall be subject during such Delivery Year to the following charges as set forth in Attachment DD to the PJM Tariff: (a) Generation Resource Rating Test Failure Charge (Attachment DD, Section 7); (b) Capacity Resource Deficiency Charge (Attachment DD, Section 8); (c) Peak Season Maintenance Compliance Penalty Charge (Attachment DD, Section 9); (d) Peak Hour Period Availability Charges and Credits (Attachment DD, Section 10); (e) Demand Resource and ILR Compliance Penalty

Charge (Attachment DD, Section 11); and (f) Emergency Procedure Charge (Attachment DD, Section 13); provided, however, that the Daily Deficiency Rate under Sections 7, 8, 9 and 13 of Attachment DD to the PJM Tariff, and the charge rates under Sections 10 and 12 of Attachment DD to the PJM Tariff, shall be the applicable Net Cost of New Entry. An FRR Entity shall have the same opportunities to cure deficiencies and avoid or reduce associated charges during the Delivery Year that a Market Seller has under Sections 7 and 10 of Attachment DD to the PJM Tariff An FRR Entity may cure deficiencies and avoid or reduce associated charges prior to the Delivery Year by procuring replacement Unforced Capacity outside of any RPM auction and committing such capacity in its FRR Capacity Plan.

7. **Annexation**

In the event a Public Power Entity annexes service territory to include new customers on sites where no load had previously existed, then incremental load on such a site shall be treated as unanticipated load growth with an obligation to have sufficient resources in the Delivery Year.

In the event a Public Power Entity annexes service territory to include load from an entity that has not elected the FRR Alternative, then:

a. For any Delivery Year for which a BRA already has been conducted, such acquiring Public Power Entity shall meet its obligations for the incremental load by paying PJM for incremental obligations (including any additional demand curve obligation) at the Capacity Resource Clearing Price for the relevant location. PJM shall use such revenues to pay capacity resources that cleared in the BRA for that LDA.

b. For any Delivery Year for which a BRA has not been conducted, such acquiring FRR Entity shall include such incremental load in its FRR Capacity Plan.

Annexation whereby a Party that has not elected the FRR Alternative acquires load from an FRR entity:

a. For any Delivery Year for which a BRA already has been conducted, PJM would consider shifted load as unanticipated load growth for purposes of determining whether to hold a Second Incremental Auction, and if a Second Incremental Auction is held, the FRR Entity would have a must offer requirement for sufficient capacity to meet the load obligation of shifted load. If no Second Incremental Auction is held, the FRR Entity may sell associated volumes of capacity into RPM or bilaterally.

b. For any Delivery Year for which a BRA has not been conducted, the FRR Entity that lost such load would no longer include such load in its FRR Capacity Plan, and PJM would include shifted load in future BRAs.

8. Savings Clause for State-Wide FRR Program

Schedule 8.1 of the RAA shall include the following savings clause:

Nothing herein shall obligate or preclude a state, acting either by law or through a regulatory body acting within its authority, from designating the Load Serving Entity or Load Serving Entities that shall be responsible for the capacity obligation for all load in one or more FRR Service Areas within such state according to the terms and conditions of this Settlement Agreement and the PJM Tariff and Reliability Assurance Agreement. Each LSE subject to such state action shall become a Party to the PJM Reliability Assurance Agreement and shall be deemed to have elected the FRR Alternative.

9. FRR Interaction with RTEP

The Settling Parties recognize the following principles concerning interaction of the FRR Alternative with the Regional Transmission Expansion Planning ("RTEP") process:

RPM auctions will be conducted and capacity clearing prices will be established for any LDA that includes loads for which the FRR Alternative has not been elected, and the payments for capacity based on such clearing prices will be considered in PJM's Office of the Interconnection's market efficiency analysis for economic-based transmission upgrades or enhancements.

RPM auctions will not be conducted for any LDA in which the FRR Alternative has been elected as to all load.

The PJM market efficiency analysis for economic-based transmission upgrades or enhancements shall be applied consistently throughout the PJM Region in accordance with applicable provisions of the PJM Tariff; provided however that for any LDA in which the FRR Alternative has been elected as to all load, such market efficiency analysis will not consider payments for capacity within such LDA.

In accordance with the settlement revisions to the RAA included herewith, an FRR Entity may include in its FRR Capacity Plan a transmission upgrade that increases the CETL into the LDA served by such FRR Entity and reduces the LDA's reliance on Capacity Resources located within such LDA.

Any Party's election of the FRR Alternative shall not change PJM's planning analysis for reliability-based transmission upgrades or enhancements.

P. Other Issues

1. Resource Operational Reliability Requirements

The Settling Parties agree that the Resource Operational Reliability Requirements included in the August 31st Filing shall be eliminated. No later than June 2008, PJM shall implement markets and/or market rules for the PJM Region, outside of the RPM markets, to address the "Operational Reliability Requirements" described in the August 31st Filing (i.e., load-following (which includes cycling) and thirty minute reserves). PJM shall make a filing, either through a stakeholder process, or if that fails, unilaterally, in time to implement this subsection by June 2008.

2. Transmission, Generation, and Demand Response Coordination

A forum shall be established for discussion dedicated to increase coordination among PJM, state siting authorities, regulatory commissions, and PJM stakeholders to identify, evaluate, and hopefully rectify, any barriers to entry of investment in generation, transmission, and demand response.

3. Barriers to Infrastructure Development

The Settling Parties agree that the market needs to be made aware of barriers to infrastructure development. To that end, as part of the annual State of the Market Report, the MMU will analyze and identify barriers, if any, to infrastructure development in each LDA.

4. Demand Response and Energy Efficiency

The Settling Parties commit to establish additional process within the PJM region for pursuing and supporting demand response and incorporating energy efficiency applications.

5. *Locational Reliability Charge*

Section 5.14 of Attachment DD is amended to clarify that the Locational Reliability Charge is assessed for each Zone (rather than an LDA), including Zones composed of multiple LDAs.

6. Fulfillment of Obligations Under EL03-236

This Settlement Agreement fulfills the obligations of Paragraph 10 of the Settlement Agreement filed and approved in PJM Interconnection, LLC, Docket No. EL03-236.

7. Firm Capacity Exports

PJM shall file separately to address appropriate charges and credits as necessary to reflect locational price differences in capacity exported from the PJM region.

8. Long-Term Market Design

Nothing herein shall preclude the development of a long-term market design that does not rely upon an administrative capacity construct at a later time.

9. Tariff Clarifications and Corrections

Attachment DD is modified to clarify and correct errors, omissions, and inconsistencies in the August 31st Filing, including (but not limited to): (a) determinations of the LDAs and increases in import capability associated with a Qualifying Transmission Upgrade (e.g., Sections 5.6.1(g) and 5.14(d)); (b) clarification to ILR payment provisions (e.g., Section 11(b)); (c) rules to ensure that incremental CTRs do not exceed the total CTRs available to loads in any LDA (e.g., Sections 5.15 and 5.16); and (d) rules governing the allocation of CTR credits in nested LDAs (e.g., section 5.15). In addition, the Reliability Assurance Agreement included with the August 31st Filing shall be updated to reflect relevant amendments to the East RAA, West RAA, or South RAA that have become effective since August 31, 2005.

III. FILING RIGHTS

Nothing contained in this Settlement Agreement shall be construed as affecting in any way PJM's right unilaterally to make application to the FERC for a change in rates, terms and conditions under section 205 of the Federal Power Act and pursuant to the Commission's Rules and Regulations promulgated thereunder. Nothing contained in the Settlement Agreement shall be construed as restricting any rights of the other parties under the Federal Power Act, including rights under section 206. Prior to PJM's exercise of its 205 rights with respect to changing the Reference Resource or the CONE Areas, PJM shall (i) hold at least one stakeholder meeting to discuss the proposed changes, and (ii) provide stakeholders at least 15 calendar days' notice of any such stakeholder meeting.

IV. APPROVAL AND EFFECTIVE DATE OF SETTLEMENT AGREEMENT

The Parties shall seek and cooperate in securing Commission approval of this Settlement Agreement. This Settlement Agreement shall become effective as of the date on which the Commission approves or accepts the Settlement Agreement in its entirety, including the revised PJM Tariff sheets in Attachments A through F.

If the Commission does not approve this Settlement Agreement by December 22, 2006, this Settlement Agreement shall terminate unless the Settling Parties agree to an extension. If the Commission should condition its approval of this Settlement Agreement or seek to require modification of any of the terms of this Settlement Agreement (a "Conditional Approval Order"), the Settling Parties shall confer and either accept the condition or negotiate in good faith, if necessary, to restore the balance of risks and benefits reflected in this Settlement Agreement as executed. Any such renegotiated settlement agreement shall be filed with the Commission. If no agreement can be reached within fifteen (15) days of the date of issuance of the Conditional Approval Order, and unless all of the Settling Parties agree to extend the time period for such negotiations, this Settlement Agreement shall terminate.

V. MISCELLANEOUS PROVISIONS

Amendments to the PJM Agreements

The amendments to the PJM Tariff, the Operating Agreement, RAA, West RAA and RAA South set forth in Attachments A through F to this Settlement Agreement implement the terms and conditions of this Settlement Agreement and are incorporated as part of this Settlement Agreement. Unless otherwise provided in this Settlement Agreement, the provisions in the August 31st Filing apply. To the extent there is a conflict between any provisions of this Settlement Agreement and the attached tariff and agreement provisions, the attached tariff and agreement provisions shall govern.

Just and Reasonable Standard. The Commission's review of any proposed modifications to this Settlement Agreement shall be based on the just and reasonable standard and not the public interest standard.

No Admissions or Precedent. This entire Settlement Agreement, and the Parties' performance of their obligations hereunder, are the result of the settlement and compromise of all the claims and actions expressly addressed in this Settlement Agreement, and neither the Settlement Agreement nor the Parties' performance hereunder shall be deemed to be an admission of any fact or of any liability. This Settlement Agreement shall be binding on the Parties only with respect to the subject matter of this Settlement Agreement, and shall not bind the Parties to apply the principles or provisions of this Settlement Agreement to any other agreement, arrangement, or proceeding. The Settlement Agreement establishes no principles and no precedent with respect to any issue in this proceeding. The acceptance of this Settlement Agreement by the Commission shall not in any respect constitute a determination by the Commission as to the merits of any allegation or contention made in this proceeding.

Entire Agreement. This Settlement Agreement, including any attachments, constitutes the entire agreement between and among the Parties, and no other agreement with regard to the matters addressed in this Settlement Agreement shall be binding on the Parties except by written amendment to this Settlement Agreement. Except for the terms and conditions enumerated in this Settlement Agreement and any attachment hereto, the Parties acknowledge and agree that the Parties have not made any other promises, warranties, or representations to each other or any other Party regarding any aspect of the settlement of the matters addressed in this Settlement Agreement. Each Party acknowledges that it has read this Settlement Agreement and executed it without relying upon any other promise, warranty, or representation, written or otherwise, of any other Party. Each Party acknowledges that no other Party has made any promise, warranty, or representation, express or implied, to induce the Parties to execute this Settlement Agreement.

Settlement Discussions. The discussions between the Parties that have produced this Settlement Agreement have been conducted on the explicit understanding, pursuant to Rule 602 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.602, that all settlement communications and discussions shall be privileged and confidential, shall be without prejudice to the position of any Party or participant making such communications or participating in any such discussions, and are not to be used in any manner in connection with this proceeding, any other proceeding, or otherwise, except to the extent necessary to enforce its terms.

Further Assurances. Following execution of this Settlement Agreement, the Parties shall prepare and execute any further pleadings, documents, or amendments to existing or future PJM agreements reasonably necessary to effectuate the Parties' intent under this Settlement Agreement.

Successors and Assigns. This Settlement Agreement is binding upon and for the benefit of the Parties and their successors and assigns.

Authorizations. Each person executing this Settlement Agreement represents and warrants that he or she is duly authorized and empowered to act on behalf of, and to sign for, the Party for whom he or she has signed.

Counterparts. This Settlement Agreement may be executed in one or more counterparts, each of which shall be deemed to be an original and all of which together shall be deemed to be one and the same instrument.

IN WITNESS WHEREOF, the Parties have caused this Settlement Agreement to be duly executed.

pjm/rpm documents/rpm settlement agreement - stripped

Signature Page for
Settlement Agreement and
Offer of Settlement
Filed on September 29, 2006 in
FERC Docket Nos. ER05-1410 and EL05-148

Robert Weinberg / PMF

Robert Weinberg
Duncan, Weinberg, Genzer & Pembroke, P.C.

On Behalf Of
Allegheny Electric Cooperative, Inc.