Internal Accounting
Assignment Methodology Description

PJM RTO Charges

September 2011

Revision History

11/18/09	DK	Clarified assignment treatment for congestion and losses when generation resources have zero MWh assigned to Off-System Sales.
09/14/11	EJG	Updated document to reflect allocation methods for all PJM RTO charges as well as changes to the original congestion and loss methods based on the better data availability and processing capability with the implementation of Allocation Manager in September 2010
09/14/11	EJG	Updated all references of ECR to PowerTracker

Purpose

The following document outlines AEP's internal accounting assignment methodologies for PJM's RTO market charges and credits. The assignment of Spot Market Energy is excluded from this document. Spot Market Energy is allocated based on the dispatch methods of PowerTracker.

This document focuses on the methods of allocation used for charges in the AEP Main PJM Account (AEPSCG) where all AEP native load and generation settles.

Appendix 4 is a table of all other active PJM subaccounts and the methods used for allocation.

Background

PJM Market

PJM operates what is referred to as a "two settlement" system. This means that market participants must indicate by noon the day prior to the operating day what their PJM settled load and generation resource mix will be the following day. Companies submitting such a load and resource mix to PJM will receive the results of PJM's reliability constrained dispatch run and will become financially committed to abide by the price and volume commitments they receive from PJM at 4:00 p.m. on the day prior to the operating day. This process represents the day-ahead settlement. PJM will then settle market participants against their day-ahead commitments for volume and price based on their actual volume relative to the price that is realized during the operating day. This deviation and related settlement represent the real-time or balancing settlement.

Congestion

Congestion costs in PJM are a means of applying a financial cost to physical power flow on constrained transmission lines. If there were no congestion on any transmission line in PJM, the Locational Marginal Price (LMP) excluding marginal losses, would be the same for all generators and loads across the entire PJM market region. However, when transmission lines become constrained, LMPs vary across the entire region. Congestion costs are simply part of the difference between what a load pays for energy and what a generator supplying the load receives for the energy it produces. Also note the LMP can be a positive or negative value.

PJM congestion costs are made up of both explicit and implicit congestion. Explicit congestion measures the difference in Locational Marginal Pricing (LMPs) between two specific points on the power system. This type of congestion applies when a Market Participant schedules a transaction between two distinct points into or out of the PJM footprint. Implicit congestion is a measure of congestion costs between a portfolio of generation resources and the loads they serve. Implicit congestion is the difference between 1) the price paid to PJM by the Load Serving Entities (LSEs) in serving their load and 2) the price paid by PJM to the generators which are used as energy resources to serve the load. The price paid by the LSEs is the load-weighted average LMP price for all the nodes in the LSEs territory. The price paid to the generators is the energy-weighted average for all the generation nodes used to serve the LSEs territory.

Transmission Losses

Transmission losses occur as electric current flows through a resistive path. Transmission lines act as resistors to the flow of energy. To receive a specific quantity of energy at one end of the line, more than the expected quantity must be injected at the other end to compensate for losses. The losses increase with lower voltage, longer lines, and higher current.

Prior to the June 1, 2007, PJM used an average loss method for determining losses on the PJM system. Losses were accounted for by adding the estimated loss MWh to the metered load amount at each LSE. Because these losses were accounted for on an average basis instead of a marginal basis, the PJM dispatch mechanism operated at less than optimum efficiency.

With the implementation of marginal losses, the load pays the Marginal Loss Price, the Generator is paid the Marginal Loss Price, and the loss revenues must be allocated. Since the LSE pays for marginal losses based on the last (and therefore highest) marginal loss component, there is an over-collection of losses revenue that is redistributed to market participants.

Marginal Losses associated with internal PJM transactions are known as implicit losses where as PJM transaction into or out of the PJM footprint have explicit losses.

Auction Revenue Rights (ARR)

Auction Revenue Rights are entitlements allocated annually by PJM to firm and network transmission Service Customers. ARRs entitle the holder to receive an allocation of the revenues from the Annual FTR Auction detailed below. As discussed below, FTRs are the instruments PJM provides its transmission customers as a means to recover day-ahead congestion charges associated with delivering energy under constrained conditions.

In its annual ARR allocation, PJM assigns each Load Serving Entity (LSE) a pro-rated amount of the MW capability from each of its historical generation resources within its load zone. Then, each LSE requests the set of ARRs based on the resources assigned and submits to PJM. LSE's may only request ARRs up to the value of their Network Service Peak Load (NSPL) value in their zone or load aggregation zone. An LSE's NSPL is its peak load set during the prior PJM planning year (June through May). This peak load is set coincidentally with PJM's annual system peak load. PJM will approve all requests that meet its criteria for simultaneous feasibility.

Financial Transmission Rights (FTR)

A Financial Transmission Right (FTR) is a financial instrument available to PJM Market Participants entitling them to a stream of revenues (or charges) based on the hourly Day Ahead energy price differences across a specific transmission path. The transmission path consists of two points: the FTR Source, and the FTR Sink.

FTRs are primarily held to protect PJM firm and network transmission service customers from increased costs due to transmission congestion when their energy deliveries are consistent with their firm reservations. Essentially, FTRs entitle the holder to rebates of PJM congestion charges paid by PJM's transmission customers.

Converting ARRs to FTRs

LSEs have the option to convert their ARRs into FTRs during the FTR Auction's 1st Round. Once an ARR is converted to an FTR, the holder receives a revenue (or charge) stream based on the hourly day-ahead price differences across each FTR source-to-sink path. PJM refers to this conversion as "self scheduling". AEP acquires its FTRs for its internal load through the self-scheduling process. AEP's load allocation process is described further below.

Acquiring FTRs

PJM offers several mechanisms for Market Participants to acquire FTRs: The Annual FTR Auction, the Monthly and Quarterly Auctions and the Secondary Market.

1. Annual FTR Auction –PJM conducts an annual process of selling and buying FTRs through a multi-round auction. The Annual FTR auction offers for sale the entire transmission capability that is available on the PJM system on a long-term basis.

2. Monthly FTR Auction – PJM conducts a monthly process of selling and buying FTRs through an auction. The Monthly FTR auction offers for sale any residual transmission capability that is available after FTRs are awarded from the Annual FTR Auction. The monthly auction also allows Market Participants an opportunity to sell FTRs that they are currently holding.

3. Secondary Market - The FTR Secondary Market is a bilateral trading system that facilitates trading of existing FTRs between PJM Members.

AEP Assignment Methodology

Background:

AEP uses the Ventyx (an ABB Company) product nMarket Allocation Manager to facilitate the allocation of PJM RTO charges. Custom Methods have been built to assign various charges based on specific accounting rules.

Methods:

I. Load Ratio Share (LRS)

Ratios used for the LRS allocation method are provided from PowerTracker based on the following calculation:

Internal Load (LSE) = CALC AEPI LOAD (as defined in entity aggregation UI = sum of East OPCO internal loads, including AEG0

Off-System Sales (OSS) = Sum of all East Non-dedicated Sales

AEP differentiates its load between Internal (LSE) and Off-System Sales (OSS) based on the underlying contracts that represent specific load. The LSE is comprised of two classes. The first is AEP Company Load. This is comprised of the summation of the net output of the five East Operating Company's generation plus their net interchange. This primarily includes AEP retail customer base. Additionally, LSE Load includes firm power sales to non-affiliated companies and to affiliated companies other than AEP Pool members. These transactions are principally characterized by the Pool member assuming the load obligation of its firm power sales commitment and the Pool member retaining the advantages from serving the firm load and are long-term. These two components represent AEP adjusted LSE Load as used in load ratio share calculations discussed within the body of this paper. The remainder should equal the sum of all Non-dedicated sales and is calculated as OSS load.

The LRS method is assigned to a charge when there is not adequate market data from PJM to attribute the cause of a charge to any one specific activity or when the use of a more granular approach would not yield a more appropriate allocation.

Invoice Line Items Assigned:

- Bill Line Item Adjustments from prior periods (Adj. line items)

- Load Reconciliation Line Items (60 day true-ups = 1400s & 2400s line items)
- Inadvertent Interchange Charge (1230)
- Meter Error Correction Charge (1250)
- Day Ahead Operating Reserve Charge (1370 &1371)
- Balancing Operating Reserve Charge (1375 & 1376)
- Reactive Services Charge (1378)

II. Fixed Percent

The Fixed Percent allocation method is used to assign a set percentage of a bill line item to LSE, OSS or TDG. A charge can be modeled to split based on percentages or assigned 100% within the application. This method is configurable by charge and date range.

Charges Assigned:

- Bill Line Item Adjustments from prior periods (Adj. line items)
- Load Reconciliation Line Items (60 day true-ups = 1400s & 2400s line items)
- Firm Point-to-Point Transmission Service Charge (1130)
- Non-Firm Point-Point Transmission Service Charge (1140)
- Day Ahead Economic Load Response Charge (1240)
- Day Ahead Scheduling Reserve Charge (1365)
- Synchronous Condensing Charge (1377)
- Black Start Service Charge (1380)
- RTO Start-up Cost Recovery Charge (1720)
- Expansion Cost Recovery Charge (1730)
- Firm Point-to-Point Transmission Service Credit (2130)
- Non-Firm Point-Point Transmission Service Credit (2140)
- Transmission Owner Scheduling, System Control & Dispatch Credit (2320)
- Day Ahead Scheduling Reserve Credit (2365)
- Reactive Services Credit (2378)
- Auction Revenue Rights Credit (2510)
- RPM Auction Credit (2600)
- Capacity Resource Deficiency Credit (2661)
- Generation Resource Rating Test Failure Credit (2662)
- Peak Hour Period Availability Credit (2665)

III. FTRs

The FTR allocation method is used to assign net revenue from Financial Transmission Rights (FTRs) on an hourly basis after total congestion (implicit + explicit) has been assigned to either LSE or OSS. In the following steps, “congestion” is referring to day-ahead and balancing (implicit and explicit) congestion costs. Net FTR revenue is referring to the sum of Transmission Congestion Target Credit + Transmission Congestion Credit Deficiency + Transmission Congestion End-of-Month Credit.

Net FTR assignment is completed in two passes of allocation:

Pass 1 is the assignment of FTR Target Credits based on FTR mappings provided by AEP Commercial Operations Congestion Analysis group. Each planning year, the annual FTRs are assigned an accounting designation (LSE, OSS or TDG) by Congestion Analysis based on the intended hedge. These mappings are stored in the nMarket database and used to assign settled value of each FTR ID. Monthly Auctions default to TDG.

Pass 2 is the assignment of FTR Deficiencies, End-of-Month Credits and 'LSE congestion make-whole'.

- FTR Deficiencies are allocated based on the ratio of positive Target Credit values assigned.
- End-of-Month Credits are allocated based on the ratio of negative Target Credit values
- 'LSE congestion make-whole' is based upon the following principle: the LSE will be made whole (net FTR revenue equal to congestion costs) prior to any assignment to OSS.

Steps for assigning LSE net FTR Credits:

1. Assign to LSE until net congestion is zero. If a balance of LSE net FTR credits remains, proceed to step 2.
2. Assign to OSS until net congestion is zero. If a balance of LSE net FTR credits remains, proceed to step 3.
3. Load ratio share the remaining LSE net FTR credit balance to the LSE and OSS

Invoice Line Items Assigned:

- FTR Auction Charge (1500)
- FTR Auction Credit (2500)
- Transmission Congestion Credit (Target) (2210)
- Transmission Congestion Credit (Deficiency) (2210)
- End-of-Month FTR Credit (2210)

IV. Transmission Loss Credit

The Transmission Loss Credit allocation method is used to assign loss surplus credits to LSE and OSS based on the hourly ratio of aggregated Loss Charges (Implicit and Explicit) of all sub-accounts designated as part of the cost reconstruction process (SCG, BCK and AUB).

If the ratio in a given hour is less than zero, then that ratio is forced to zero and by default 100% of the credit will be allocated to the positive ratio.

Charges Assigned:

- Transmission Losses Credit (2220)

V. Charge Netting

The Charge Netting allocation method is used to assign ancillary service charges based on the net of charges and credits.
Since ancillary services are used by loads, PJM charges the load for the service while the generators receive credits for providing the service. If the net amount is a charge, this reflects that the native load customers of AEP purchased all or a portion of the service from PJM (AEP did not receive awards to supply its load requirement). If the net amount is a credit, the effect is AEP supplied all its requirements for its load for that service and was able to sell additional to PJM, thus making a sale to the market. As a result, net charges are recorded to LSE accounts while net credits would be recorded to OSS accounts.
The net credit/charge is determined on a daily basis. Adjustments are treated independently. Adjustment charges are assigned to LSE, while credits are assigned to OSS. Netting of adjustments is not possible based on the level of data detail provided by PJM.

Invoice Line Items Assigned:

- Reactive Service Charge (1330)
- Reactive Service Credit (2330)
- Regulation Service Charge (1340)
- Regulation Service Creict (2340)
- Synchronized Reserve Charge (Tier1 & Tier 2) (1360)
- Synchronized Reserve Credit (Tier1 & Tier 2) (2360)
- Bill Line Item Adjustments for Reactive, Regulation and Synchronized Reserves

VI. Implicit Congestion and Loss

The Implicit Congestion and Loss allocation method is used to assign implicit transmission congestion and loss charges by component type based on the following guidance:

PJM provides the details associated with the LMP (Energy, Congestion and Losses) which AEP uses to directly calculate and verify congestion and losses at the transaction point level. These transaction point results are assigned to the LSE and Off-System Sales (OSS) based upon the hourly PowerTracker results. PowerTracker is an internal AEP cost reconstruction program that allocates energy for each hour using unit generation and purchased energy sources. The LSE will be assigned congestion and loss costs based on the difference between the LMP congestion and loss component for the actual LSE load and the resources (generation and purchases) that serve this load as determined by the economic dispatch results of PowerTracker. Similarly, OSS will be assigned congestion and loss costs based on the difference between the LMP congestion and loss component for the actual OSS load and the resources (generation and purchases) that fulfill the Off-System Sales as determined by the economic dispatch results of PowerTracker. In hours where generation resources have zero MWh's allocated to OSS all implicit congestion and losses will be assigned to the LSE.

Component Type Methods:

- **Load** - Congestion and Losses associated with load are directly assigned to LSE or OSS based upon the designation of the load within the PJM account. Currently, the load in the AEPSCG account represents AEP Native Load and therefore congestion and losses for load are allocated 100% to LSE. If an instance occurs where the load in a PJM account is blended between the LSE and OSS, the implicit congestion and losses will be assigned on a load ratio basis.

- **Generation** - Congestion and Losses associated with generation is allocated to the LSE or OSS based upon the individual hourly unit results of the real-time economic dispatch within PowerTracker

- **Sales & Exports** - Sales are OSS by nature; therefore congestion associated with these components is directly assigned to OSS

- **Purchases & Imports -** Purchases that have congestion and losses are assigned to the LSE or OSS based upon the hourly results of the real-time economic dispatch within PowerTracker.

- **Incs & Decs** – virtual bids and offers are assumed part of the trading and hedging strategy of AEP. As a result, implicit congestion and losses associated with these components is directly assigned to OSS. Margin of these transactions is re-classed from OSS to trading in separate Gross Margin Analysis accounting processes.

Invoice Line Items Assigned:

- Day Ahead Transmission Implicit Congestion Charge (1210)

- Balancing Transmission Implicit Congestion Charge (1215)
- Day Ahead Transmission Implicit Loss Charge (1220)
- Balancing Transmission Implicit Loss Charge (1225)

VII. Purchase Ratio

The Purchase Ratio allocation method is used to assign a charge based on the aggregated hourly ratio of purchases allocated to OSS not tied to a specific transaction point.

Hourly explicit transmission congestion and losses for day-ahead energy transactions equal the scheduled MWh times the difference between day-ahead sink and source transmission congestion and loss costs and assessed to the buyer (or point-to-point transmission customer, if applicable).
Hourly explicit transmission congestion and losses for balancing energy transactions equal any real-time deviations from day-ahead transaction MWh times the difference between real-time sink and source transmission congestion and loss costs and assessed to the buyer (or point-to-point transmission customer, if applicable).

A Balancing Operating Reserve Credit implies an increase in RT generation from what was cleared DA. This also results in increased Off-system sales (Spot Market). When cost reconstruction is run, more purchases will have to be assigned to OSS to cover the additional spot market sales while the LSE will get the benefit of additional, lower-cost generation. Therefore, the BORC uses the Purchase Ratio allocated to LSE versus OSS as a basis for the assignment of the credits.

Invoice Line Items Assigned:

- Day Ahead Transmission Explicit Congestion Charge (1210)
- Balancing Transmission Explicit Congestion Charge (1215)
- Day Ahead Transmission Explicit Loss Charge (1220)
- Balancing Transmission Explicit Loss Charge (1225)
- Balancing Operating Reserve Credit (2375)
- Balancing Operating Reserve Lost Opportunity Cost Credit (2375)

VIII. Manual Allocations (outside of system)

Manual allocation methods are used to properly assign PJM line items to LSE OSS or TDG in a manner that has not been implemented in the nMarket Allocation Manager system.

Manual methods are limited to "one-off" scenarios that did not justify the cost of development in the initial system implementation.

Invoice Line Items Assigned:

- Planning Period Congestion Uplift Charge (1218)
- Planning Period Congestion Uplift Credit (2218)
- Cross Monthly Congestion Credit (2210) – Excess Allocations to prior months ONLY
- PJM Administration Fees (1300-1318)

Cross Monthly Congestion Credit Allocations – PJM allocates surplus transmission congestion revenue on a monthly basis to any prior month credit deficiencies within the planning period. These "Cross-Monthly Congestion Credits" are added by PJM to the current month invoice line item for Transmission Congestion Credits. Detailed statements of the credits are not available for upload into the nMarket system. As a result, a summary report from the PJM MSRS website is used to determine how the excess credits were assigned within the planning period by month. These monthly values are allocated to OSS LSE and TDG based on the specific monthly final FTR Deficiency allocation ratios.

If there were no prior month deficiencies, PJM will hold the surplus congestion revenues until the end of the planning period when they will be allocated proportionately to FTR holders with net positive FTR target allocations for that planning period. This annual credit (May invoice) will be allocated to OSS LSE and TDG proportionately to the aggregate net positive FTR target allocations internally allocated for that planning period

Planning Period Congestion Uplift – Each year (May invoice) any FTR credit deficiencies remaining at the end of a planning period are eliminated and then reallocated among FTR holders to yield a uniform ratio of deficiency. PJM performs a market uplift to try and ensure a uniform assignment of planning period deficiencies across FTR participants. This annual uplift (May invoice) will be allocated to OSS LSE and TDG proportionately to the aggregate net positive FTR target allocations internally allocated for that planning period. See Appendix 2 for example of 2010-2011 planning year uplift.

PJM Administration Fees –Allocation of PJM Administration fees are done in compliance with FERC Order 668 wherein operating costs for the RTOs are categorized into 3 different accounts for financial reporting. PJM publishes allocation ratios quarterly or annually (based on the Fee) allowing market participants to align the allocation of RTO administration costs with the reporting of administrative revenues reported by the RTO. This Admin fee allocation was excluded from the scope of the nMarket Allocation Manager project. These fees are allocated within a one-off schedule that is provided to accounting outside of the nMarket system.

Appendix 1

Special Assignments

- **Buckeye Load and Cardinal 2 &3**

  AEP has a contract with Buckeye that is defined as an off-system sales contract. The Buckeye load that AEP is contractually responsible for is settled through a separate PJM sub-account (AEPBCK). This sub-account contains the FTRs associated with this load. These FTRs are primarily covering congestion between Cardinal units 2 & 3 and the Buckeye load points. This coincides with the Buckeye contract, which states that the majority of their load is filled with these two units. Special handling is performed within PowerTracker to ensure that Cardinal 2 & 3 serve Buckeye's load in relationship to the contract parameters. This is necessary to guarantee that the congestion and losses from these units are to follow Buckeye and, hence, be appropriately allocated to OSS.

Appendix 2

Planning Period Congestion Uplift PJM Calculation:

(A): $25,058,413.89 Planning Period Congestion Uplift Credit (return of monthly deficiencies originally charged throughout the 10/11 planning year)

(B): ($24,454,577.88) Planning Period Congestion Uplift Charge to AEP (based on AEP annual ratio of FTR Target Credit value to market total)

(C): $603,836.01 Net Planning Period Congestion Uplift (credit to AEP)

(B) Uplift is calculated as AEP's ratio to the market based on the total planning period FTR Target Credit. (See below):

$	164,516,153.38	AEP Positive FTR Target Credit ($)
$	1,710,574,928.46	Total PJM Positive FTR Target Credit ($)
	0.096175941	AEP ratio of FTR Target Credit $
$	254,269,182.42	PJM Total FTR shortfall ($)
$	24,454,577.88	AEP Planning Period Congestion Uplift Charge

Appendix 3

AEPSCG (PJM Main Account) Charge Method Assignments

Load Ratio Share

1210A - Adj. to Day-ahead Transmission Congestion

1215A - Adj. to Balancing Transmission Congestion

1218A - Planning Period Congestion Uplift

1220A - Adj. to Day-ahead Transmission Losses

1225A - Adj. to Balancing Transmission Losses

1230 - Inadvertent Interchange Charge

1230A - Adj. to Inadvertent Interchange

1250 - Meter Error Correction Charge

1250A - Adj. to Meter Error Correction

1370 - Day-Ahead Operating Reserve Charge

1370A - Adj. to Day-ahead Operating Reserve

1371 - Day-Ahead Operating Reserve for Load Response Charge

1371A - Adj. to Day-ahead Operating Reserve for Load Response

1375 - Balancing Operating Reserve Charge

1375A - Adj. to Balancing Operating Reserve

1376 - Balancing Operating Reserve for Load Response Charge

1376A - Adj. to Balancing Operating Reserve for Load Response

1378 - Reactive Services Charge

1378A - Reactive Services

1410 - Load Reconciliation for Transmission Congestion Charge

1410A - Adj. to Load Reconciliation for Transmission Congestion

1420 - Load Reconciliation for Transmission Losses Charge

1420A - Adj. to Load Reconciliation for Transmission Losses

1430 - Load Reconciliation for Inadvertent Interchange Charge

1430A - Adj. to Load Reconciliation for Inadvertent Interchange

1441 - Load Reconciliation for PJM Scheduling, System Control and Dispatch Srvc Refund Chg (Sch 9-1)

1441A - Adj. to Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Refund

1442 - Load Reconciliation for Schedule 9-6 - Advanced Second Control Center Charge

1444 - Load Reconciliation for Market Monitoring Unit (MMU) Funding Charge

1444A - Adj. to Load Reconciliation for Market Monitoring Unit (MMU) Funding

1445 - Load Reconciliation for FERC Annual Charge Recovery Charge

1445A - Adj. to Load Reconciliation for FERC Annual Recovery

1446 - Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding Charge

1446A - Adj. to Load Reconciliation for Organization of PJM States, Inc. (OPSI) Funding

1447 - Load Reconciliation for North American Electric Reliability Corporation (NERC) Charge

1447A - Adj. to Load Reconciliation for North American Electric Reliability Corporation (NERC)

1448 - Load Reconciliation for Reliability First Corporation (RFC) Charge

1448A - Adj. to Load Reconciliation for Reliability First Corporation (RFC)

1478 - Load Reconciliation for Balancing Operating Reserve Charge

1478A - Adj. to Load Reconciliation for Balancing Operating Reserve

1490 - Load Reconciliation for Reactive Services Charge

1980A - Adj. to Miscellaneous Bilateral

2210A - Adj. to Transmission Congestion

2217A - Adj. to Planning Period Excess Congestion

2218A - Planning Period Congestion Uplift Credit

2220A - Adj. to Transmission Losses

2350 - Energy Imbalance Service Credit

2370 - Day-Ahead Operating Reserve Credit - Transaction Credits

2370 - Day-Ahead Operating Reserve Generator Credit

2420 - Load Reconciliation for Transmission Losses Credit

2420A - Adj. to Load Reconciliation for Transmission Losses

2980A - Adj to Miscellaneous Bilateral

Fixed Percent

1100A - Adj to Network Integration Transmission Service

1104 - Network Integration Transmission Service Offset Charge

1108 - Transmission Enhancement Charge

1108A - Adj. to Transmission Enhancement

1130 - Firm Point-to-Point Transmission Service Charge

1140 - Non-Firm Point-to-Point Transmission Service Charge

1140A - Adj. to Non-Firm Point-to-Point Transmission Service

1240 - Day-Ahead Economic Load Response Charge

1240A - Adj. to Day-ahead Economic Load Response

1241A - Adj. to Real-time Economic Load Response

1245A - Adj. Emergency Load Response

1365 - Day-Ahead Scheduling Reserve Charge

1365A - Adj. to Day-ahead Scheduling Reserve

1377 - Synchronous Condensing Charge

1377A - Adj. to Synchronous Condensing

1380 - Black Start Service Charge

1380A - Adj. to Black Start Service

1400 - Load Reconciliation for Spot Market Energy Charge

1400A - Adj. to Load Reconciliation for Spot Market Energy

1440 - Load Reconciliation for PJM Scheduling, System Control and Dispatch Service Charge (Sch 9-1)

1440A - Adj. to Load Reconciliation for PJM Scheduling, System Control and Dispatch Service

1450 - Load Reconciliation for Trans Owner Scheduling, System Control and Dispatch Service Charge

1450A - Adj. to Load Reconciliation for Transmission Owner Scheduling, System Control and Disp. Srvc

1460 - Load Reconciliation for Regulation and Frequency Response Service Charge

1460A - Adj. to Load Reconciliation for Regulation and Frequency Response Service

1470 - Load Reconciliation for Synchronized Reserve Charge

1470A - Adj. to Load Reconciliation for Synchronized Reserve

1475 - Load Reconciliation for Day-Ahead Scheduling Reserve Charge

1480 - Load Reconciliation for Synchronous Condensing Charge

1480A - Adj. to Load Reconciliation for Synchronous Condensing

1720 - RTO Start-up Cost Recovery Charge

1730 - Expansion Cost Recovery Charge

2100 - Network Integration Transmission Service Credit

2130 - Firm Point-to-Point Transmission Service Credit

2130A - Adj. to Firm Point-to-Point Transmission Service

2140 - Non-Firm Point-to-Point Transmission Service Credit

2140A - Adj. to Non-Firm Point-to-Point Transmission Service

2320 - Transmission Owner Scheduling, System Control and Dispatch Service Credit

2320A - Adj. to Transmission Owner Scheduling, System Control and Dispatch Service

2365 - Day-Ahead Scheduling Reserve Credit

2365A - Adj. to Day-ahead Scheduling Reserve

2378 - Reactive Services Condensing Credit

2378 - Reactive Services Condensing Lost Opportunity Cost Credit

2378 - Reactive Services Generator Credit

2378 - Reactive Services Lost Opportunity Cost Credit

2380 - Black Start Service Credit

2510 - Auction Revenue Rights Credit

2600 - RPM Auction Credit

2661 - Capacity Resource Deficiency Credit

2661A - Adj. to Capacity Resource Deficiency

2662 - Generation Resource Rating Test Failure Credit

2662A - Adj. to Generation Resource Rating Test Failure

2665 - Peak-Hour Period Availability Credit

2665A - Adj. to Peak-Hour Period Availability

FTRs

1500 – Financial Transmission Rights Auction Charge

2210 – End-of-Month FTR Credit

2210 – Transmission Congestion Credit (Deficiency)

2210 – Transmission Congestion Credit (Target Credit)

2500 – Financial Transmission Rights Auction Credit

Transmission Loss Credit

2220 - Transmission Losses Credit

Charge Netting

1330 – Reactive Supply and Voltage Control from Generation and Other Sources Service Charge

1330A – Adj. to Reactive Supply and Voltage Control from Generation and Other Sources Service

1340 – Regulation and Frequency Response Service Charge

1340A – Adj. to Regulation and Frequency Response Service

1360 – Synchronized Reserve Tier 1 Charge

1360 – Synchronized Reserve Tier 2 Charge

1360A – Adj. to Synchronized Reserve

2330 – Reactive Supply and Voltage Control from Generation and Other Sources Service Credit

2340 – Regulation and Frequency Response Service Credit

2340A – Adj. to Regulation and Frequency Response Service

2360 – Synchronized Reserve Tier 1 Credit

2360 – Synchronized Reserve Tier 1 Credit – Load Response

2360 – Synchronized Reserve Tier 2 Credit

2360 – Synchronized Reserve Tier 2 Credit – Load Response

2360A – Adj. to Synchronized Reserve

Implicit Congestion and Loss

1210 - Day-Ahead Transmission Implicit Congestion Charge

1215 - Balancing Transmission Implicit Congestion Charge

1220 - Day-Ahead Transmission Implicit Losses Charge

1225 - Balancing Transmission Implicit Losses Charge

Purchase Ratio

1210 – Day-Ahead Transmission Explicit Congestion Charge

1215 – Balancing Transmission Explicit Congestion Charge

1220 – Day-Ahead Transmission Explicit Losses Charge

1225 – Balancing Transmission Explicit Losses Charge

2375 – Balancing Operating Reserve Credit – Transaction Credits

2375 – Balancing Operating Reserve Generator Credit

2375 – Balancing Operating Reserve Lost Opportunity Cost Credit

2375 – Balancing Operating Reserve Startup Cancellation Credit

2375A – Adj. to Balancing Operating Reserve

2376 – Balancing Operating Reserve for Load Response Credit

Manual Allocations

1218 – Planning Period Congestion Uplift Charge

2218 – Planning Period Congestion Uplift Credit

Appendix 4

PJM Sub Account Charge Method Assignments

PTCPT_CD	Method	Description	Assignment
AEPAMB	Fixed Percent	Fixed Percent Pass Through	Trading
AEPAPB	Fixed Percent	Fixed Percent Pass Through	Trading
AEPAPD	Fixed Percent	Fixed Percent Pass Through	LSE
AEPAUB	LRS CAM	Load Ratio CAM	LSE,OSS
	Trans Loss Credit CAM	Allocation of Transmission Loss Credit	LSE,OSS
AEPBCK	Fixed Percent	Fixed Percent Pass Through	OSS
	Trans Loss Credit CAM	Allocation of Transmission Loss Credit	LSE,OSS
AEPBMB	Fixed Percent	Fixed Percent Pass Through	Trading
AEPCCG	Fixed Percent	Fixed Percent Pass Through	Trading
AEPCCL	Fixed Percent	Fixed Percent Pass Through	Trading
AEPCOW	Fixed Percent	Fixed Percent Pass Through	Trading
AEPCSD	Fixed Percent	Fixed Percent Pass Through	LSE
AEPDDB	Fixed Percent	Fixed Percent Pass Through	Trading
AEPDMB	Fixed Percent	Fixed Percent Pass Through	Trading
AEPDMB	Fixed Percent	Fixed Percent Pass Through	Trading
AEPDSM	Fixed Percent	Fixed Percent Pass Through	Trading
AEPDSX	Fixed Percent	Fixed Percent Pass Through	Trading
AEPFSZ	Fixed Percent	Fixed Percent Pass Through	Trading
AEPGFE	Fixed Percent	Fixed Percent Pass Through	Trading
AEPGFE	Fixed Percent	Fixed Percent Pass Through	Trading
AEPGIC	Fixed Percent	Fixed Percent Pass Through	Trading
AEPGTE	Fixed Percent	Fixed Percent Pass Through	Trading
HREA	Fixed Percent	Fixed Percent Pass Through	Trading
AEPIMD	Fixed Percent	Fixed Percent Pass Through	LSE
LTRKN	Fixed Percent	Fixed Percent Pass Through	Trading
AEPOPD	Fixed Percent	Fixed Percent Pass Through	LSE
AEPPDC	Fixed Percent	Fixed Percent Pass Through	Trading
AEPPDC	Fixed Percent	Fixed Percent Pass Through	Trading
AEPPMB	Fixed Percent	Fixed Percent Pass Through	Trading
AEPPPL	Fixed Percent	Fixed Percent Pass Through	Trading
AEPPPS	Fixed Percent	Fixed Percent Pass Through	Trading
AEPSBY	Fixed Percent	Fixed Percent Pass Through	Trading
AEPTOB	Fixed Percent	Fixed Percent Pass Through	Trading
AEPVOG	Fixed Percent	Fixed Percent Pass Through	Trading
AEPWOH	Fixed Percent	Fixed Percent Pass Through	Trading