CUSTOMER GUIDE TO PJM BILLING

- Billing Line Items include PJM Open Access Transmission Tariff (OATT) references, PJM Operating Agreement (OpAgr) references, and PJM Manual references.
- Reports are available for viewing, printing, and downloading from PJM's Market Settlement Reporting System (MSRS).

Billing Line Item	Description	Reports
Network Integration Transmission Service (OATT Section 34, Attachments H-1 through H-17, Attachment H-A, and TOA Section 7.8 Manual 27, Section 5)	Network customers pay daily demand charges to PJM transmission owners using the applicable zonal or non-zone Network Integration Transmission Service rates. All network customers in the AP zone receive rebates to hold them harmless from the network rate conversion upon PJM integration. For transmission owners (except those in ATSI, PPL, ComEd, Dayton, Duke, and Duquesne zones), the charges for their own transmission facilities are not actually paid (i.e., exempted with an equal amount credits) and are shown only to identify their cost responsibility as ordered by FERC. ***<u>Charges</u>:*** Daily demand charges calculated as network customers' daily network service peak load contribution times 1/365th of the applicable zonal rate(s) for the zone(s) in which the network load is located. Monthly negative offset charges are rebated to AP zone network customers based on the applicable rates in PJM tariff Attachment H-11, section 4. Non-zone network service peak load contributions are coincident with the PJM Region peak. Virginia Network Load customers in the Dominion Zone pay applicable rates for Underground Billing under FERC Opinion No. 555. ***<u>Credits</u>:*** PJM zonal network transmission service revenues allocated to the applicable zone's transmission owners on a transmission revenue requirement basis. PJM non-zone network revenues allocated to transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	***NITS Charge Summary*** ***NITS Credit Summary*** ***NITS Offset Charge Summary*** ***Non-Zone NITS Credit Summary*** ***Underground Transmission Service Charge Summary*** ***Underground Transmission Service Credit Summary***
Firm Point-to-Point Transmission Service (OATT Section 13.7, Schedule 7, and TOA Section 7.8 Manual 27, Section 6)	Firm point-to-point transmission customers pay demand charges for reserved capacity at the applicable tariff rates based on the term of the reservations. There is no charge for reserved capacity with a MISO point of delivery. ***<u>Charges</u>:*** Monthly demand charges for daily, weekly, monthly, and yearly delivery calculated based on the transmission customer's reserved capacity times the applicable tariff rate. The total demand charge in any week, pursuant to a reservation for daily delivery, shall not exceed the weekly delivery rate times the highest amount of reserved capacity in any day during such week. ***<u>Credits</u>:*** Total firm transmission service revenues allocated to PJM transmission owners based on transmission revenue requirement ratio shares, with the ComEd, AEP, and Dominion shares further allocated to their respective zonal network customers based on demand charge ratios.	***Firm PTP Charges*** ***Firm PTP Credit Summary***
Non-Firm Point-to-Point Transmission Service (OATT Sections 14.5 & 27A, Schedule 8 Manual 27, Section 6)	Non-firm point-to-point transmission customers pay demand charges for reserved capacity at the discounted rate. There is no charge for reserved capacity with a MISO point of delivery. ***<u>Charges</u>:*** Monthly demand charges for hourly, daily, weekly, and monthly delivery calculated based on the transmission customer's reserved capacity (in MWh) times the discounted rate of $0.67/MWh. Rebates are provided for transaction MWh curtailed by PJM and for transmission congestion charges. ***<u>Credits</u>:*** Total non-firm transmission service revenues allocated to PJM network and firm point-to-point transmission customers in proportion to their monthly demand charges.	***Non-Firm PTP Charges*** ***Non-Firm PTP Credit Summary***
Transmission Enhancement (OATT Schedule 12)	All network customers and merchant transmission owners pay transmission owners for required transmission enhancement projects in accordance with the zonal cost responsibility allocations in the appendix to Schedule 12. All transmission projects collecting these payments are on PJM's website under Transmission Services/Formula Rates. ***<u>Charges</u>:*** All network customers serving load in a responsible zone pay for that zone's applicable projects' revenue requirements in proportion to their network service peak load share in that zone, and responsible merchant transmission owners also pay their share of applicable revenue requirements. Note that several EDCs bear these charges for the default suppliers in their territory. ***<u>Credits</u>:*** Total revenues allocated to the applicable transmission enhancement project owners, or the applicable transmission zone network customers for zonal TOs that include these project costs in their network rates.	***Transmission Enhancement Charge Summary*** ***Transmission Enhancement Credit Summary***

Billing Line Item	Description	Reports
Spot Market Energy (OpAgr Schedules 1-3.2.1 & 3.3.1 and OATT Schedule 4 Manual 28, Section 3)	Day-ahead Spot Market energy position MWs are calculated in hourly intervals for cleared day-ahead generation and increment offers, demand, decrement, and load response bids, and day-ahead energy transactions. Real-time Spot Market energy position MWs are calculated in five minute increments for real-time energy transactions, load (without losses), generation, and metered tie flows, as applicable. . In situations where five minute energy position interval data has not been provided, the energy position value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions. ***Day-ahead Charges:*** Net Day-ahead Spot Market energy positions are charged at the PJM-wide day-ahead system energy price for each hour. Charges are positive for energy purchased from the PJM Spot Market (i.e. energy withdrawals) and negative for energy delivered to the PJM Spot Market (i.e. energy injections)and totals are summed for each hour. ***Balancing Charges:*** Net real-time deviations from day-ahead energy positions are charged at one-twelfth the PJM-wide real-time system energy price for each five minute interval. In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the hourly PJM-wide real-time system energy price on a two-month billing lag.	***DA Daily Energy Transactions*** ***RT Daily Energy Transactions*** for customer review and verification ***Spot Market Energy Charge Summary*** ***Energy & Inadvertent Load Recon Charge Summary*** ***Energy Market and Congestion Loss Charge Details*** ***Balancing Generator LMP Charges***

Transmission Congestion (OpAgr Schedules 1-3.2.4, 3.4.1, & 5.1-5.2 Manual 28, Section 8)	The increased energy costs due to redispatch during the applicable interval when the PJM transmission system is constrained are assessed to market participants based on the congestion price component of LMPs. Day-Ahead revenues collected are allocated as credits to FTR holders. Balancing Revenues are allocated as credits based on real-time load plus exports ratio shares. ***Day-ahead Charges:*** Day-ahead Implicit Congestion charges are calculated hourly as the sum of day-ahead withdrawal values (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at the applicable locations' day-ahead congestion prices) minus the sum of day-ahead injection values (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at the applicable locations' day-ahead congestion prices). Explicit Congestion charges for day-ahead energy transactions are calculated hourly and equal the scheduled MWh times the difference between day-ahead sink and source congestion prices. These charges are assessed to the buyer (or point-to-point transmission customer, if applicable). ***Balancing Charges:*** Balancing Implicit Congestion charges are calculated for each five minute interval as the sum of balancing withdrawal congestion values (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead versus real-time load without losses, and sale transactions, priced at one-twelfth of the applicable locations' real-time congestion prices) minus the sum of balancing injection congestion values (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead versus real-time generation and purchase transactions, priced at one-twelfth of the applicable locations' real-time congestion prices). In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour. Explicit Congestion charges for balancing energy transactions are calculated for each five minute interval and equal any real-time deviations from the transaction MWs cleared day-ahead times one-twelfth of the difference between the real-time sink and source congestion prices. In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour. These charges are assessed to the buyer (or point-to-point transmission customer, if applicable). ***Day-ahead Credits:*** Total day-ahead congestion revenues (including net day-ahead MISO and NYISO Market-to-Market adjustments) are allocated as hourly credits based on FTR target allocations (FTR MW times the difference between day-ahead FTR sink and source congestion prices). The monthly total of excess hourly congestion credits and FTR Auction net revenues remaining after distribution to ARRs are used to proportionately reduce any remaining FTR target deficiencies in all hours of the month. Any additional excess monthly congestion revenues are allocated to previous deficient months of the planning period. ***Balancing Credits:*** Total Balancing Transmission Congestion Charges (including MISO and NYISO real-time Market-to-Market adjustments and inadvertent interchange congestion contribution) are allocated among the PJM market participants in proportion to their real-time load (de-rated for transmission losses) plus their real-time PJM exports as a percentage of the total PJM load (excluding losses) and exports. ***Reconciliation Charges and Credits:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink congestion price on a two-month billing lag.	***Transmission Congestion Charge Summary*** ***Explicit Congestion Charges*** ***Energy Market and Congestion Loss Charge Details*** ***FTR Target Credits*** ***Hourly Transmission Congestion Credits*** ***Congestion and Loss Load Recon Charges*** ***Congestion Uplift Charge Summary*** ***Network ARR Target Credit Summary*** ***Cross-Monthly Congestion Credit Summary*** ***Balancing Transmission Congestion Credit Summary*** ***Balancing Transmission Congestion Load Reconciliation Credit Summary***

Planning Period Congestion Uplift (OpAgr Schedules 5.2.5 & 5.2.6 Manual 28, Section 8)	For planning years in which the sum of actual Transmission Congestion credits paid to FTR holders during the planning year was less than the sum of their FTR Targets, Planning Period Congestion Uplift credits are awarded to the FTR holders at the end of the planning year (May) to completely fulfill those remaining FTR Target deficiencies. Planning Period Congestion Uplift credits and Planning Period Congestion Uplift charges can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. The "Planning Period Congestion Uplift credit" is a "make-whole" congestion credit to FTR holders to satisfy any previously unfulfilled FTR Target Credits that remain at the end of the planning year. A summary of FTR Targets and all applicable Congestion Credits broken down by month can be viewed in the "Cross-Monthly Congestion Credit Summary" report in MSRS. Select the "All Billed" option for the period from 6/1/12 through 5/31/13 to see the complete set of details. The "Planning Period Congestion Uplift charge" is the participant's share of the allocated costs of providing the Uplift credits. Charges are allocated to FTR holders in proportion to their net positive total FTR Target Credits for the planning year. Details of this charge allocation can be viewed in the "Congestion Uplift Charge Summary" report in MSRS. The calculation for the Uplift charge is: (positive FTR Target credit / Total PJM Positive FTR Target Credit) * PJM Total FTR and ARR Uplift Credit. The uplift process is also outlined in Manual 28, sections 8.1 and 8.4.4	***Congestion Uplift Charge Summary*** ***Cross-Monthly Congestion Credit Summary***
Planning Period Excess Congestion (OpAgr Schedule 5.2.6 Manual 28, Section 8.4.4)	For planning years in which the sum of total PJM congestion revenues collected during the planning year was greater than the sum of FTR holders' total net FTR Targets, Planning Period Excess Congestion credits are awarded to the ARR holders at the end of the planning year (May) to distribute those remaining excess congestion revenues. Planning Period Excess Congestion credits can only occur at the end of the Annual Planning Period (which runs from June 1st through May 31st), so they will only apply to May monthly billing statements. Planning Period Excess Congestion credits are allocated to ARR holders in proportion to their net positive total ARR Target Credits for the planning year.	***Cross-Monthly Congestion Credit Summary***

Billing Line Item	Description	Reports
Transmission Losses (OpAgr Schedules 1-3.2.5, 3.4.2, & 5.4-5.5 Manual 28, Section 9)	The increased costs of energy due to transmission losses represented in the PJM network model are assessed to market participants based on the loss component of LMPs, and the revenues collected are allocated to market participants' serving load and delivering PJM exports (that pay for PJM transmission service). ***Day-ahead Charges:*** Day-ahead Transmission Loss charges are calculated hourly as the sum of day-ahead withdrawal loss values (i.e., all cleared day-ahead demand/decrement/load response bids and sale transactions priced at the applicable locations' day-ahead loss prices) minus day-ahead injection loss values (i.e., all cleared day-ahead generation/increment offers and purchase transactions priced at the applicable locations' day-ahead loss prices). Explicit loss charges for day-ahead energy transactions are calculated hourly and equal the scheduled MWh times the difference between day-ahead sink and source loss prices. These charges are assessed to the buyer (or point-to-point transmission customer, if applicable). ***Balancing Charges:*** Balancing Loss charges are calculated for each five minute interval as balancing withdrawal loss values (i.e., all deviations between demand/decrement/load response bids and sale transactions cleared day-ahead versus real-time load, without losses, and sale transactions priced at one-twelfth of the applicable locations' real-time loss prices) minus balancing injection loss values (i.e., all deviations between generation/increment offers and purchase transactions cleared day-ahead versus real-time generation and purchase transactions priced at one-twelfth of the applicable locations' real-time loss prices). In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour.. Explicit loss charges for balancing energy transactions are calculated for each five minute interval and equal any real-time deviations from day-ahead transaction MW times one-twelfth of the difference between real-time sink and source loss prices. In situations where five minute energy position interval data has not been provided (including all day-ahead energy position data), the energy position value provided will be flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions and deviations. Charges may be positive or negative depending on the direction of the real-time deviation from the day-ahead energy position, and totals are summed for each hour. These charges are assessed to the buyer (or point-to-point transmission customer, if applicable). ***Credits:*** Total hourly loss revenues, both day-ahead and balancing (including loss contribution of inadvertent interchange and spot market energy imbalance) allocated as hourly credits based on ratio shares of real-time load (without losses) plus exports that pay for transmission service (with non-firm exports receiving 31% of their allocation). ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable source/sink loss price on a two-month billing lag. ***Reconciliation Credits:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total loss credits divided by the total MWh of PJM real-time load plus exports (that pay for transmission service, with non-firm exports receiving 31% of their allocation) on a two-month billing lag.	***Transmission Loss Charge Summary*** ***Explicit Loss Charges*** ***Energy Market and Congestion Loss Charge Details*** ***Transmission Loss Credit Summary*** ***Congestion and Loss Load Recon Charges*** ***Transmission Loss Load Recon Credit Summary***
Inadvertent Interchange (OpAgr Schedule 1-3.7 Manual 28, Section 18)	***Charges:*** PJM hourly total inadvertent interchange charges (+/-) priced at the load weighted-average PJM real-time LMP and allocated based on real-time load ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the PJM-wide real-time system energy price on a two-month billing lag.	***Inadvertent Interchange Charge Summary*** ***Energy & Inadvertent Load Recon Charge Summary***
Load Response (OpAgr, just prior to Schedule 2 Manual 28, Section 11)	***Credits:*** Day-ahead and real-time economic and real-time pre-emergency and emergency load response credits are provided to CSPs equal to the reduced MWs times LMP. In situations where five- minute interval data has not been provided, the Load Response energy value provided will be scaled or flat-profiled across each of the five minute intervals of the provided period in order to obtain five minute interval energy positions. Those MW positions are then multiplied by one-twelfth of the applicable interval real-time zonal or aggregate LMP to determine credits, which are then summed for the hour. ***Charges:*** For day-ahead and real-time economic load response, the charges are allocated to all real-time load where load is served in a zone that has benefitted from load reductions plus real-time exports. For pre-emergency and emergency load response, all balancing energy market participants are allocated charges using the same method as for PJM emergency energy purchases.	***Load Response Summary*** ***Real-time Load Response Credits*** ***Econ Load Response Zonal Charge Allocations*** ***Emergency Load Response Allocation Summary*** ***Emergency Load Response Allocation Credits***

Meter Error Correction (OpAgr Schedule 1-3.6 Manual 28, Section 12)	***Charges:*** Monthly charges (+/-) to PJM fully-metered EDCs and generators for corrections to metered energy values, with PJM Mid-Atlantic 500kV corrections allocated based on real-time load ratio shares, using the applicable generator or PJM load weighted-average real-time LMP for the month. Meter correction charges for any external PJM tie-line corrections are allocated to all LSEs based on real-time load (without losses) ratio shares. Effective February 2010, EDCs may elect to have their charges (+/-) directly allocated by PJM to LSEs in their zone based on load ratio shares if all LSEs in the EDC territory concur.	***Meter Correction Charge Summary*** ***Meter Correction Allocation Charge Summary***
Emergency Energy (OpAgr Schedules 1-3.2.6, 3.3.4, 3.5.1, & 4.3 Manual 28, Section 10)	PJM emergency energy transactions (made on behalf of market participants) are priced at 150% of LMP at the appropriate PJM interface in accordance with the PJM agreements with adjacent control areas. ***Charges:*** For each applicable five-minute interval, net costs of emergency energy purchased by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position, except for purchases for external control areas' MinGen Emergencies where costs are allocated to deviations that create a longer position. ***Credits:*** For each applicable five-minute interval, net revenues from emergency energy sold by PJM are allocated to real-time deviations from day-ahead net interchange that create a shorter real-time position and to any curtailed exports, except for PJM MinGen Emergency sales where revenues are allocated to deviations that create a longer position.	***Emergency Energy Charge and Credit Allocation Summary*** ***Emergency Energy Transactions***
Billing Line Item	**Description**	**Reports**
PJM Scheduling, System Control & Dispatch Service (OATT Schedules 1 and 9-1 through 9-6 Manual 27, Section 2)	***Charges:*** PJM's monthly operating expenses for the following service categories are allocated to PJM members on an unbundled basis. Charge refunds are provided in the quarter following any quarter in which there is a cumulative collection above PJM's operating expenses in excess of the allowable reserve. Control Area Administration – 2019 rate of $0.2153/MWh (with $0.0 refund rate for 3Q2019) charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use (in MWh) includes network customers' real-time load and point-to-point customers' real-time energy use. Financial Transmission Rights Administration – 2019 rate of $0.0029/FTR MWh (with $0.0/FTR MWh refund for 3Q2019) charged to FTR holders based on FTR MW and hours each FTR is in effect (regardless of congested hours and dollar value of FTR). 2019 rate of $0.0019/bid-hour (with $0.0 refund rate for 3Q2019) charged to FTR Auction participants based on the number of hours associated with each FTR obligation bid submitted in an FTR Auction (this rate is multiplied by 5 for FTR options). Market Support – 2019 rate of $0.0475/MWh (with $0.0 refund rate for 3Q2019) charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. 2019 rate of $0.0710 (with $0.0 refund rate for 3Q2019) is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. Regulation and Frequency Response Administration – 2019 rate of $0.2889/Regulation MWh (with $0.0 refund rate for 3Q2019) charged to customers based on regulation obligation and regulation provided. Capacity Resource and Obligation Management – 2019 rate of $0.1100/MW-day (with $0.0 refund rate for 3Q2019) charged to LSEs based on their daily unforced capacity obligations and to capacity resource owners based on their daily unforced capacity (including FRRs). Costs of Advanced Second Control Center (AC^2) – This rate has been terminated. Market Support Offset –3Q2019 rate of $0.0044/MWh refunded to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids to reflect the reimbursement made to offset the PJM Settlement, Inc. charges. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the Control Area Administration Service Rate plus the Market Support Service Rate for transmission customers on a two-month billing lag. Charge refund amounts are also reconciled using the applicable refund rate billing determinants.	***Schedule 9 and 10 Charge Details*** ***Advanced Second Control Center Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
PJM Settlement, Inc. (OATT Schedule 9-PJMSettlement Manual 27, Section 2.2)	***Charges:*** 3Q2019 rate of $0.0044/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. This charge funds the administration of PJM Settlement, Inc. who acts as the contractual counterparty to PJM market transactions and performs the billing collection and credit management services for PJM members.	***Schedule 9 and 10 Charge Details***

MMU Funding (OATT Schedule 9-MMU Manual 27, Section 2)	***Charges:*** 2019 rate of $0.0053/MWh charged to transmission customers based on their network load and exports, to providers of generation and imports, and to day-ahead energy market participants based on their accepted increment offers, decrement bids, and up-to congestion bids. 2019 rate of $0.0046 is charged for each energy bid/offer segment price/quantity pair submitted, including those submitted during the rebidding period. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the MMU rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
FERC Annual Recovery (OATT Schedule 9-FERC Manual 27, Section 2)	***Charges:*** 2019 rate of $0.0774/MWh charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the FERC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Organization of PJM States, Inc. (OPSI) Funding (OATT Schedule 9-OPSI Manual 27, Section 2)	***Charges:*** 2019 rate of $0.00077/MWh charged to transmission customers based on their usage of the PJM transmission system. Monthly transmission use includes network customers' real-time load and point-to-point transmission customers' real-time energy transactions. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the OPSI rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Consumer Advocates of PJM States, Inc. (CAPS) Funding (OATT Schedule 9-CAPS Manual 27, Section 2)	***Charges:*** 2019 rate of $0.00056/MWh charged to each customer using Network Integration and Point-to-Point Transmission Service each month a charge equal to the CAPS Funding Rate times the total quantity in MWhs of energy delivered to the load (including losses) that such customer serves in the PJM Region during such month. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the CAPS rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
North American Electric Reliability Corp. (NERC) (OATT Schedule 10-NERC Manual 27, Section 2)	***Charges:*** 2019 rate of $0.0145/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. Each calendar year, any over or under collection of NERC's actual costs are trued up in that year's December billing cycle. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the NERC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Reliability First Corp. (RFC) (OATT Schedule 10-RFC Manual 27, Section 2)	***Charges:*** 2019 rate of $0.0223/MWh charged to transmission customers based on their energy delivered to load in the PJM Region, excluding load in the Dominion and East Kentucky Power Cooperative zones. Each calendar year, any over or under collection of RFC's actual costs are trued up in that year's December billing cycle. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the RFC rate on a two-month billing lag.	***Schedule 9 and 10 Charge Details*** ***Schedule 9 & 10 Load Recon Charge Summary***
Transmission Owner Scheduling, System Control and Dispatch Service (OATT Schedule 1A Manual 27, Section 2)	All Transmission Customers purchase this from PJM to schedule energy through, out, within, or into PJM. ***Charges:*** Monthly charges for the operation of the PJM transmission owners' control centers are calculated for transmission customers based on their monthly usage of the PJM transmission system. Point-to-Point Transmission Customers pay a pool-wide rate of $0.0912/MWh based on their energy deliveries including losses and network customers pay applicable zonal rates provided in Schedule 1A of the Tariff based on the real-time MWh of monthly load they serve. ***Credits:*** The charges collected from network customers for each zone are provided to the applicable transmission owner, and the non-zone revenues (e.g., received from point-to-point customers) are allocated to PJM transmission owners based on fixed percentage shares provided in Schedule 1A of the Tariff. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using zonal $/MWh billing determinants equal to the applicable zonal Schedule 1A rates on a two-month billing lag.	***Sched 1A Charge Summary*** ***Sched 1A Credit Summary*** ***Sched 1A Load Recon Charge Summary***

Reactive Supply and Voltage Control from Generation and Other Sources Service (OATT Schedule 2 Manual 27, Section 3)	All Transmission Customers purchase this from PJM to maintain acceptable transmission voltages. ***Credits:*** Monthly credits provided to generation and transmission owners with FERC-approved reactive revenue requirements. ***Charges:*** Monthly pool-wide reactive revenue requirements allocated as charges to point-to-point customers (and to network customers in transmission zones with no reactive revenue requirements) based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining reactive revenue requirements for each transmission zone not recovered from point-to-point customers are allocated to the network customers serving load in that zone based on their monthly network service peak load contributions.	***Reactive Charge Summary***
Regulation and Frequency Response Service (OpAgr Schedules 1-3.2.2, 3.2.2A, 3.3.2, & 3.3.2A and OATT Schedule 3 Manual 28, Section 4)	PJM conducts a regulation market to continuously balance generation resources with PJM load and to maintain Interconnection frequency within acceptable limits. ***Credits:*** Generators and demand resources receive five minute interval credits for pool- and self-scheduled regulation (with consideration of the resource's performance) priced at one-twelfth of the regulation market capability clearing price. Generators and demand resources receive five minute interval credits for pool- and self-scheduled regulation (with consideration of the resource's performance and the ratio between the requested mileage for the regulation dispatch signal assigned to the resource and the mileage for the traditional regulation signal (mileage ratio)) priced at one-twelfth of the regulation market performance clearing prices. Additional credits provided to pool-scheduled regulating resources for any unrecovered portion of regulation offer plus opportunity cost. ***Charges:*** PJM LSEs have an hourly regulation obligation equal to their real-time load (without losses) ratio share of regulation supplied excluding mileage (adjusted for any bilateral regulation transactions). Hourly charges are allocated based on obligation ratio shares times the sum of total PJM Regulation credits awarded for each hour of the Operating Day In addition, any lost opportunity or other unrecovered cost payments that PJM provides to regulation suppliers are allocated to regulation market purchasers based on the amount of Regulation they purchased from the market in that hour. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total regulation market charges divided by the total MWh of PJM real-time load served on a two-month billing lag.	***Regulation Summary*** ***Regulation Credits*** ***Load Response Regulation Credits*** ***Reg Load Recon Charge Summary***
Synchronized Reserve (OpAgr Schedules 1-3.2.3A & 3.3.5 and OATT Schedule 5 Manual 28, Section 6)	PJM conducts synchronized reserve markets to ensure the capability of synchronized generation and demand resources that can be converted fully into energy within ten minutes. ***Credits:*** For each five minute interval, generators that increase output and demand resources that decrease consumption in response to a synchronized reserve event at times when the applicable reserve zone or sub-zone Non-Synchronized Reserve Clearing Price is zero receive Tier 1 credits equal to response MWs times one-twelfth of the synchronized reserve energy premium. At times when the non-synchronized reserve clearing price is non-zero, resources receive Tier 1 credits equal to the lesser of the five minute actual response MWs or the five minute estimated Tier 1 MWs times one-twelfth of the applicable reserve zone's Synchronized Reserve Market Clearing Price. For each five minute interval, resources receive Tier 2 credits for pool- and self-scheduled synchronized reserve priced at one-twelfth of the applicable reserve zone's Synchronized Reserve Market Clearing Price. Additional credits provided to pool-scheduled synchronized reserve resources for any portion of synchronized reserve offer plus opportunity cost, energy use cost, and start-up cost not recovered via Synchronized Reserve Market Clearing Price revenues. ***Charges:*** PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total assignments (adjusted for any bilateral synchronized reserve transactions). Tier 1 charges for each participant equal their ratio share of the total Tier 1 credits based on the amount of Tier 1 synchronized reserve applied to their obligation. Tier 2 hourly charges are allocated based on adjusted obligation ratio shares times the sum of total PJM Synchronized Reserve Tier 2 credits awarded for each hour of the Operating Day. In addition, Synchronized Reserve lost opportunity charges are calculated each hour by allocating total PJM Synchronized Reserve lost opportunity credits for the hour to market participants that do not meet their hourly obligation, in proportion to their Synchronized Reserve purchases for the hour. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	***Synchronized Reserve Credit Summary*** ***Synchronized Reserve Tier 1 Credits*** ***Synchronized Reserve Tier 2 Credits*** ***Synchronized Reserve Obligation Details*** ***Synchronized Reserve Tier 1 Charge Summary*** ***Synchronized Reserve Tier 2 Charge Summary*** ***Load Response Tier 1 Credits*** ***Load Response Tier 2 Credits*** ***Synchronized Reserve Load Recon Charge Summary***

Non-Synchronized Reserve **(**OpAgr Schedules 1-3.2.3A.001 & 3.3.5A Manual 28, Section 7)	PJM conducts non-synchronized reserve markets to ensure the capability of generation off-line and available to provide energy within ten minutes as necessary to meet the primary reserve requirement. ***Credits:*** Five minute interval credits are provided to generation resources supplying non-synchronized reserve at one-twelfth of the applicable Non-Synchronized Reserve Clearing Price. Additional credits are provided to non-synchronized reserve resources for each five minute interval for any portion of non-synchronized reserve opportunity costs not recovered via Non-Synchronized Reserve Market Clearing Price revenues. ***Charges:*** PJM LSEs that are not part of an agreement to share reserves with external entities have an hourly non-synchronized reserve obligation equal to their real-time load (without losses) ratio share of their reserve market's total non-synchronized reserve supplied (adjusted for any bilateral non-synchronized reserve transactions). Hourly charges are allocated based on obligation ratio shares times the sum of total PJM Non-Synchronized Reserve credits awarded for each hour of the Operating Day. Additional charges are assessed for any unrecovered cost payments that PJM provides to non-synchronized reserve suppliers based on adjusted obligation ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable reserve zone's $/MWh billing determinant calculated as the total applicable reserve zone Non-Synchronized Reserve charges divided by the total MWh of PJM real-time load served in the that market on a two-month billing lag.	***Non-Synchronized Reserve Summary*** ***Non-Synchronized Reserve Credits*** ***Non-Synchronized Reserve Load Recon Charge Summary***

Billing Line Item	Description	Reports
Day-ahead Scheduling Reserve (OpAgr Schedules 1-3.2.3A.01 and OATT Schedule 6 Manual 28, Section 19)	PJM conducts day-ahead scheduling reserve markets to ensure the capability of generation and demand resources to meet reserve requirements on a forward basis. ***Credits:*** Daily credits provided to eligible generator and demand response resources cleared day-ahead based on their cleared MWh of day-ahead scheduling reserve times the day-ahead scheduling reserve clearing price. ***Charges:*** PJM LSEs have an hourly day-ahead scheduling reserve obligation equal to their real-time load (without losses) ratio share of the market's total assignments (adjusted for any bilateral day-ahead scheduling reserve transactions). Total hourly cost of day-ahead scheduling reserve is allocated based on obligation ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load on a two-month billing lag.	***Day-ahead Scheduling Reserve Summary*** ***Day-ahead Scheduling Reserve Credits*** ***Day-ahead Scheduling Reserve Load Recon Charge Summary***
Billing Line Item	**Description**	**Reports**
Operating Reserve (OpAgr Schedules 1-3.2.3 & 3.3.3 and OATT Schedule 6 Manual 28, Section 5 and Section 11)	To ensure adequate operating reserve and for spot market support, pool-scheduled generation and demand resources that operate as requested by PJM are guaranteed to fully recover their daily offer amounts. ***Day-ahead Credits:*** Daily credits provided to pool-scheduled generators, demand response, and transactions cleared day-ahead for any portion of their offer amount in excess of their scheduled MWh times day-ahead bus LMP. ***Balancing Credits:*** Daily credits for specified operating period segments are provided to eligible pool-scheduled generators, demand response, and import transactions in real-time, and will be evaluated on a five minute interval basis for any portion of their offer amount in excess of: (1) scheduled MWh times day-ahead bus LMP; (2) MW deviation from day-ahead schedule times one-twelfth of real-time bus LMP; (3) any day-ahead operating reserve credits; (4) any day-ahead scheduling reserve market revenues in excess of offer plus opportunity cost; (5) any synchronized reserve market revenues in excess of offer plus opportunity, energy use, and startup costs; (6) any non-synchronized reserve market revenues in excess of opportunity costs and (7) any applicable reactive services credits. Cancellation credits are based on actual costs submitted to PJM Market Settlements. Credits for lost opportunity costs are also evaluated on a five minute interval basis and are provided to generators reduced or suspended by PJM for reliability purposes. ***Day-ahead Charges:*** Total daily cost of operating reserve in the day-ahead market excluding the total cost for resources scheduled to provide Black Start Service, Reactive Services or transfer interface control is allocated based on day-ahead load (including cleared demand, demand response, and decrement bids) plus exports ratio shares. ***Balancing Charges:*** Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Deviations is allocated based on regional shares of five minute interval real-time locational deviations from the following day-ahead scheduled quantities of: (1) cleared generation offers (only for generating units not following PJM dispatch instructions and not assessed deviations based on their real-time desired MWs); (2) cleared increment offers and purchase transactions; and (3) cleared demand bids, decrement bids, and sale transactions. In situations where five minute interval data has not been provided (including all day-ahead data), the hourly MW value provided will be scaled or flat-profiled across each of the applicable five minute intervals of the hour in order to allow for the calculation of MW deviations on a five minute interval basis. Total daily cost of operating reserve in the balancing market related to resources identified as Credits for Reliability is allocated based on regional shares of real-time load (without losses) plus exports. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an daily basis using a $/MWh billing determinant calculated as the total charges allocated to real-time load plus exports divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	***Operating Reserve Charge Summary*** ***Balancing Operating Reserve Generator Credit Details*** ***Operating Reserve Lost Opportunity Cost Credits*** ***Operating Reserve Transaction Credits*** ***Operating Reserve Generator Deviations*** ***Operating Reserve Generator Deviations – 5 min*** ***Operating Reserve Deviation Summary*** ***Operating Reserve Deviation summary – 5 min*** ***Operating Reserve Transaction Credits*** ***Balancing Operating Reserves for Load Response Credit*** ***Operating Reserve for Load Response Deviation Charge Summary*** ***Operating Reserve for Load Response Charge Allocations*** ***Regional Balancing Operating Reserve Charge Summary*** ***Balancing Operating Reserve Load Recon Charge Summary*** ***CT Lost Opportunity Cost Forfeiture***
Synchronous Condensing (OpAgr Schedule 1-3.2.3	***Credits:*** Daily credits for condensing and energy use costs are calculated on a five minute interval basis and are provided to eligible synchronous condensers dispatched by PJM for purposes other than synchronized reserve, post-contingency, or reactive services.	***Synchronous Condensing Credits*** ***Synchronous Condensing***

Manual 28, Section 5)	***Charges:*** Total daily cost of synchronous condensing (not for synchronized reserve or reactive services) is allocated based on real-time load (without losses) plus export ratio shares. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using a $/MWh billing determinant calculated as the total charges divided by the total MWh of PJM real-time load plus exports on a two-month billing lag.	***Charge Summary*** ***Synchronous Condensing Load Recon Charge Summary***

Billing Line Item	Description	Reports
Reactive Services (OpAgr Schedule 1-3.2.3B Manual 28, Section 5)	Generating resources whose output is altered by PJM for the purpose of maintaining reactive reliability are guaranteed to fully recover their daily offer amounts or to be compensated for their lost opportunity costs. ***Credits:*** Daily credits are calculated on a five minute interval basis for each eligible generator in real-time and equal the operating reserve credits for generation increased, or equal the lost opportunity costs for generation reduced or instructed to condense, to provide reactive services. ***Charges:*** Total daily cost of reactive services and the total day-ahead Operating Reserve credits for resources scheduled to provide Reactive Services or transfer interface control is allocated separately for each PJM transmission zone based on real-time load (without losses) ratio shares in the applicable transmission zone. ***Reconciliation Charges:*** Retail load schedules with reconciliation data (in kWh) provided by the applicable EDC are reconciled on an hourly basis using the applicable zone's $/MWh billing determinant calculated as the total applicable zone's charges divided by the total MWh of real-time load served in the that zone on a two-month billing lag.	***Reactive Services Credits*** ***Synchronous Condensing Credits*** ***Reactive Services Charge Summary*** ***Reactive Svcs Load Recon Charge Summary***
Black Start Service (OATT Schedule 6A Manual 27, Section 7)	All Transmission Customers purchase this from PJM to ensure the reliable restoration following a shut down of the PJM transmission system. ***Credits****:* Monthly credits provided to generators with approved black start revenue requirements. ***Charges****:* Monthly pool-wide black start revenue requirements and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing allocated as charges to point-to-point customers based on their monthly peak usage of the PJM transmission system. Monthly peak usage equals the total hourly amounts of transmission capacity reserved, and not curtailed by PJM, divided by 24. The remaining black start revenue requirements nominated by each zonal Transmission Owner and day-ahead and balancing Operating Reserve credits associated with scheduling resources for black start service or testing not recovered from point-to-point customers are allocated to the network customers serving load in that transmission zone based on their monthly network service peak load contributions.	***Black Start Charge Summary***
Fuel Cost Policy Penalty (OpAgr Schedule 2, Section 5 Manual 15, Section 2)	Market Sellers are required to have a PJM-approved Fuel Cost Policy for energy market units submitting cost-based offers. A Fuel Cost Policy Penalty is assessed if PJM determines and the Market Monitoring Unit (MMU) agrees or the MMU determines and PJM agrees that a cost-based offer is not compliant with the PJM-approved Fuel Cost Policy or other applicable cost-based offer guidelines in Schedule 2 of Operating Agreement. ***Charges:*** An hourly charge is assessed to the participant that applies to all hours that the Market Seller does not have a PJM approved Fuel Cost Policy or a cost offer not in accordance with its Fuel Cost Policy. ***Credits:*** Fuel Cost Policy Penalties are allocated as credits based on real-time load ratio share in the hour for which the Fuel Cost Policy Penalty has been assessed.	***Fuel Cost Policy Penalty Charge Details*** ***Fuel Cost Policy Penalty Credit Allocation Summary***
Financial Transmission Rights Auction (OpAgr Schedule 1-7.3.8 Manual 28, Section 16)	PJM conducts annual and monthly FTR auctions for the transaction of FTRs at market clearing prices. Net auction revenues are allocated daily to ARR holders and then FTR holders as excess congestion revenues. ***Charges:*** Monthly auction charges are calculated for each market participant for each FTR (in 0.1 MW increments) purchased in the annual or monthly auctions based on the FTR's market price. ***Credits:*** Monthly auction credits are calculated for each market participant for each FTR (in 0.1 MW increments) sold in the annual or monthly auctions based on the FTR's market price.	***FTR Auction Charges and Credits***
Auction Revenue	Auction Revenue Rights (ARR) are entitlements to receive an allocation of net FTR auction revenues that are allocated annually and reassigned daily to network and firm point-to-point transmission customers.	***ARR Target Credits***

Rights (OpAgr Schedule 1-7.4 Manual 28, Section 17)	***Credits:*** Annual FTR auction net revenues are allocated as daily credits based on ARR target allocations, which equal the ARR MW (divided by the number of auction rounds) times the difference between auction clearing prices at the ARR sink and source. Any ARR target deficiencies may be proportionately eliminated by any monthly FTR auction net revenues and excess congestion revenues in that planning period.	

Billing Line Item	Description	Reports
RPM Auction (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	***Credits:*** Each sell offer for generation, demand, or qualified transmission upgrade resource MW cleared in an RPM Auction is paid the applicable resource's clearing price in the applicable auction. Resource make-whole payments are also provided to sell offers that clear less than the minimum amount specified. Sell offers are adjusted by approved unit-specific transactions for cleared capacity. ***Charges:*** Each buy bid MW cleared in an incremental auction adjusted by cleared buy bid transactions pays the applicable LDA's resource clearing price. Resource make-whole payments for an incremental auction are also allocated as charges to Market Buyers based on the MW shares of cleared buy bids adjusted by cleared buy bid transactions for the incremental auction. Resource make-whole payments for the base residual auction and the portion of the resource make-whole payment for an incremental auction that would be based on PJM cleared buy bids are allocated as charges to LSEs in the applicable LDA via the Final Zonal Capacity Price.	***RPM Auction Charges and Credits*** ***RPM Auction Make-Whole Charge Summary*** ***RPM Auction Charges*** ***RPM Auction Credits***
Locational Reliability (OATT Att. DD, Section 5.14 Manual 18, Section 9.2)	***Charges:*** Each LSE is charged for their daily unforced capacity obligation priced at the applicable zonal capacity price for the delivery year.	***Locational Reliability Charge Summary***
Capacity Transfer Rights (OATT Att. DD, Section 5.15 Manual 18, Section 9.3)	To recognize the value of import capability to constrained LDAs, Capacity Transfer Rights (CTRs) are allocated to LSEs in those LDAs to offset their higher load charges. ***Credits:*** CTRs equal to the unforced capacity imported into the LDA (less any incremental CTRs) are allocated to LSEs in that LDA based on daily unforced capacity obligations. These MW allocations are priced at the difference between the LDA's clearing price and the unconstrained price.	***CTR Credit Summary***
Incremental Capacity Transfer Rights (OATT Att. DD, Section 5.16, OATT Schedule 12A (b) Manual 18, Section 9.3)	Incremental CTRs are provided to fund for transmission upgrades (not including qualifying transmission upgrades cleared in the Base Residual Auction) that increase import capability into a constrained LDA. Incremental CTRs for Incremental-Rights Eligible Required Transmission Enhancements are determined and allocated as defined in Schedule 12A of the Tariff. ***Credits:*** Incremental CTR MW are priced at the sum of: 1) locational price adder of the sink LDA minus that of the Source LDA from the Base Residual Auction; and 2) locational price adder of the sink LDA minus that of the source LDA from the Second Incremental Auction multiplied by the increase in unforced capacity imported into the sink LDA in the Second Incremental Auction compared to the Base Residual Auction, divided by the base unforced capacity imported into the sink LDA. Incremental CTR credits determined for an Incremental-Rights Eligible Required Transmission Enhancement are allocated to the responsible customers that are assigned cost responsibility for the transmission enhancements in accordance with the cost allocations in the appendix to Schedule 12. Responsible customers include Network customers, Transmission Customers with an agreement for Firm Point-to-Point Service, or Merchant Transmission Facility Owners. Network customers serving load in a responsible zone receive credits in proportion to their network service peak load share in that zone.	***Incremental CTR Credits*** ***Incremental CTR for Required Transmission Enhancement Credits***
Auction Specific MW Transaction (OATT Att. DD, Section 5.14 Manual 18, Section 9.3)	Bilateral capacity transactions for multi-day durations are settled in the PJM capacity markets. ***Charges:*** Sellers are charged for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect. ***Credits:*** Buyers are credited for the transaction MW times the transaction's pricing point for each day for which the transaction is in effect.	***Auction Specific MW Transaction Charges and Credits***

Load Management Compliance Penalty (OATT Att. DD, Section 11 Manual 18, Section 9.1)	Sellers with zonal aggregate committed Demand Resources that cannot demonstrate hourly real-time performance pay a penalty charge which is allocated to Demand Resource providers and, potentially, LSEs. This billing is performed on a three-month lag. ***Charges:*** For each non-compliant reduction event, under-compliance MW (on an unforced capacity basis) are charged at the lesser of one divided by the actual number of events during the year or 0.50 of the Weighted Annual Revenue Rate. The Weighted Annual Revenue Rate equals the average rate for all cleared Demand Resources, weighted by the MWs cleared at each price, multiplied by the number of days in the Delivery Year. The total Compliance Penalty Charge for the Delivery Year is capped at the annual revenue received for such resources. ***Credits:*** Revenues from events in a given month are allocated to Demand Resources that reduced in excess of their commitment. Any resource credit by event is capped at their excess MW times 1/5th of their Annual Revenue Rate. Revenues above that cap are allocated to LSEs based on their average daily unforced capacity obligations during the month of the event.	***Load Management Compliance Penalty Charges*** ***Load Management Compliance Penalty Credits*** ***Load Management Compliance Penalty Residual Credits***
Capacity Resource Deficiency (OATT Att. DD, Section 8 Manual 18, Section 9.1)	Capacity resources that are unable or unavailable to deliver unforced capacity, and do not obtain replacement unforced capacity to satisfy their cleared sell offer pay this charge which is allocated to eligible LSEs. ***Charges:*** Each capacity resource's deficiency MW for each day it is deficient pays the daily deficiency rate. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
Generation Resource Rating Test Failure (OATT Att. DD, Section 7 Manual 18, Section 9.1)	Generation capacity resources that fail a capacity test pay this charge which is allocated to eligible LSEs. This billing is performed in the June billing cycle after the conclusion of the delivery year. ***Charges:*** Each capacity resource's installed capacity minus its highest rating in the relevant testing period (on an unforced capacity basis) pays a daily deficiency rate which is the weighted average capacity resource clearing price plus the higher of: 1) 0.2 times the weighted average capacity resource clearing price or 2) $20/MW-day; ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
Qualifying Transmission Upgrade Compliance Penalty (OATT Att. DD, Section 12 Manual 18, Section 9.1)	Cleared qualifying transmission upgrades delayed in coming into service for the applicable delivery year pay a daily penalty charge which is allocated to eligible LSEs. ***Charges:*** Capacity market sellers with import capability cleared in a base residual auction based on a qualifying transmission upgrade are charged each day that the upgrade is not in service during the applicable delivery year and the seller does not obtain replacement capacity resources. The import capability MW are charged at the higher of the following rates: 1) two times the locational price adder of the applicable LDA; or 2) the Net CONE less the clearing price in the applicable LDA. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
Peak Season Maintenance Compliance Penalty (OATT Att. DD, Section 9 Manual 18, Section 9.1)	Each generation capacity resource must have available unforced capacity during the peak season to satisfy its cleared MW. This billing is performed in the June billing cycle after the conclusion of the delivery year. ***Charges:*** Each generation capacity resource's cleared MW for each day of the peak season that is out-of-service on a maintenance outage not authorized by PJM pays the daily deficiency rate times (1-EFORd). ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Non-Compliance Charge Summary*** ***Deficiency Credit Summary***
Peak-Hour Period Availability (OATT Att. DD, Section 10 Manual 18, Section 9.1)	To ensure capacity resource availability during critical peak hours, incentives are provided to resources that exceed expected availability and penalties are assessed to those who fall short. This billing is performed in the August billing cycle after the conclusion of the delivery year. ***Charges:*** Net peak period capacity shortfall MW are charged at the weighted average resource clearing price for the applicable LDA (except for FRR capacity that are charged at the LDA's Net CONE). ***Credits:*** Total revenues for the delivery year for each LDA are allocated to resources with peak period excesses based on their excess MW. Since these allocations are capped, any remaining credits are allocated to LSEs that paid a Locational Reliability charge based on their daily unforced capacity obligations.	

Load Management Test Failure (OATT Att. DD, Section 11A Manual 18, Section 9.1)	Sellers with committed Demand Resources that fail performance tests pay a penalty charge which is allocated to eligible LSEs. This billing is performed in the December billing cycle for June-December, then it is performed monthly for January-May. ***Charges:*** Net capability testing shortfall MW are charged daily at the weighted annual revenue rate for the applicable zone plus the greater of 0.2 times that weighted annual revenue rate or $20/MW-day. ***Credits:*** Total revenues each day are allocated to LSEs that paid a Locational Reliability charge that day based on their daily unforced capacity obligations.	***Load Management Test Failure Charge Summary*** ***Load Management Test Failure Credit Summary***

Billing Line Item	Description	Reports
RTO Start-up Cost Recovery (OATT Attachments H-13 and H-14)	All network customers in the AEP Zone pay AEP (expected to end May 2020). ***Charges:*** Monthly charges to AEP zonal network customers are calculated based on network service peak load contributions at a 2019 rate of $103.879/MW/year.	***RTO Startup Cost Recovery Charge Summary***
Unscheduled Transmission Service (OpAgr Sch1-5.3a Manual 28, Section 14)	***Charges:*** Hourly charges to NYISO for any costs incurred due to unscheduled use of the PJM transmission system in accordance with the PJM-NYPP Interconnection Agreement Schedule 6.02. ***Credits:*** Total hourly charges are allocated as credits with monthly excess congestion credits.	***Hourly Transmission Congestion Credits***
Ramapo Phase Angle Regulators (OpAgr Schedule 1-5.3b Manual 28, Section 15)	***Credits:*** PJM's share of monthly carrying charges for Ramapo Phase Angle Regulators (PARs) are credited to NYISO in accordance with the NYPP-PJM PARs Facilities Agreement. ***Charges:*** Charges are allocated to PJM Mid-Atlantic transmission owners based on transmission revenue requirement shares.	***Ramapo PAR Charge Summary***
Generation Deactivation (OATT Part V)	Revenues are collected for generators requesting retirement where PJM studies find reliability issues that require the generation to continue operating. Cost allocations to zonal load and firm withdrawal rights are determined by PJM based on the beneficiaries. These responsible customers pay the generation owners a share of the Deactivation Avoidable Cost Rate or the FERC-approved Cost of Service Recovery Rate. Any time that the zonal cost allocations change, notice is provided to the Markets and Reliability Committee, Market Implementation Committee, and Market Settlements Subcommittee prior to the change being implemented. ***Charges:*** Charges are being collected for RC Cape May Holdings, LLC BL England 2 generator based on a Reliability Must-Run Rate Schedule that ended April 30, 2019. The monthly charges were allocated on a one month lag in accordance with the following study results: https://pjm.com/-/media/planning/gen-retire/2019-zonal-cost-allocation-for-retaining-bl-england-u2-generator.ashx Note that the zonal charges are further allocated based on network service peak load contributions within the applicable zone. Per the settlement agreement, there is a 90 day period to also process true-up costs.	***Generation Deactivation Charge Summary*** ***Generation Deactivation Refund Charge Summary***
Deferred Tax Adjustment (OATT Attachments H-7B, H-8A and H-17C)	***Charges:*** Each Network Customer that serves one or more end-use customers taking distribution service from PPL Electric Utilities Corporation, Duquesne Light Company, or PECO Energy Company under its applicable retail tariff on file with the Pennsylvania Public Utility Commission ("PPL Electric Distribution Customers", "Duquesne Electric Distribution Customers", and/or "PECO Energy Company Distribution Customers") shall pay a Monthly Deferred Tax Adjustment Charge. This charge permits PPL Electric, Duquesne Light and PECO Energy Company to recover a deferred income tax liability that is currently unfunded due to a Pennsylvania Public Utility decision to flow-through to customers certain income tax benefits.	***Deferred Tax Adjustment Charge Summary***