SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give transmission service customers and PJM members an offset against congestion costs in the Day-Ahead Energy Market. An FTR provides the holder with revenues, or charges, equal to the difference in congestion prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides the holder with revenues, or charges, based on the price differences across the specific ARR transmission path that result from the Annual FTR Auction. FTRs and ARRs provide a hedge against congestion costs, but neither FTRs nor ARRs provide a guarantee that transmission service customers will not pay congestion charges. ARR and FTR holders do not need to physically deliver energy to receive ARR or FTR credits and neither instrument represents a right to the physical delivery of energy.

In PJM, FTRs have been available to network service and long-term, firm, point-to-point transmission service customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998. Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[1] Since the introduction of this auction, FTRs have been available to all transmission service customers and PJM members. Network service and firm point-to-point transmission service customers can take allocated ARRs or the underlying FTRs through a self scheduling process. On June 1, 2007, PJM implemented marginal losses in the calculation of LMP. Since then, FTRs have been valued based on the difference in congestion prices rather than the difference in LMPs.

Firm transmission service customers have access to ARRs/FTRs because they pay the costs of the transmission system that enables firm energy delivery. Firm transmission service customers receive requested ARRs/FTRs to the extent that they are consistent both with the physical capability of the transmission system and with ARR/FTR requests of other eligible customers.

The *2009 State of the Market Report for PJM* focuses on the annual ARR allocations, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2008 to 2009 planning period which covers June 1, 2008, through May 31, 2009, and the 2009 to 2010 planning period which covers June 1, 2009, through May 31, 2010. The *2009 State of the Market Report for PJM* also analyzes the results of the 2010 to 2013 Long Term FTR Auction that covers three consecutive planning periods: June 1, 2010 through May 31, 2011, June 1, 2011 through May 31, 2012 and June 1, 2012 through May 31, 2013.

1 87 FERC ¶ 61,054 (1999).

Overview

Financial Transmission Rights

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. The second Long Term FTR Auction is being conducted during the 2009 to 2010 planning period and covers three consecutive planning periods between 2010 and 2013. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. The principal binding constraints limiting the supply of FTRs in the 2010 to 2013 Long Term FTR Auction include the Carroll Transformer and the Philipsburg – Shawville line. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2009 to 2010 planning period include the AP South Interface and the Mahans Lane — Tidd line.[2] Market participants can also sell FTRs. In the 2010 to 2013 Long Term FTR Auction, total FTR sell offers were 51,582 MW. In the Annual FTR Auction for the 2009 to 2010 planning period, total FTR sell offers were 142,154 MW, up from 83,453 MW during the 2008 to 2009 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2009) of the 2009 to 2010 planning period, there were 1,962,836 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the 2010 to 2013 Long Term FTR Auction, total FTR buy bids were 1,064,620 MW. In the Annual FTR Auction for the 2009 to 2010 planning period, total FTR buy bids were 1,436,335 MW, down from 2,181,273 MW during the 2008 to 2009 planning period. Total FTR self scheduled bids were 68,589 MW for the 2009 to 2010 planning period, a decrease from 72,851 MW for the 2008 to 2009 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2009) of the 2009 to 2010 planning period, total FTR buy bids were 5,339,818 MW.

2 During calendar years 2004 and 2005, PJM conducted the phased integration of five control zones. Four of these, American Electric Power (AEP), The Dayton Power & Light Company (DAY), Duquesne Light Company (DLCO) and Dominion, were eligible for direct allocation FTRs during the 2006 to 2007 planning period, but not the 2007 to 2008, the 2008 to 2009 or the 2009 to 2010 planning period. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2009 State of the Market Report for PJM*, Volume II, Appendix A, "PJM Geography."

- **FTR Credit Issues.** One participant defaulted for a small amount, which was covered by collateral, in 2009, and one participant had losses on annual FTRs that extended into 2009. PJM made multiple filings in 2008 and 2009 to reform its credit policies, focusing particularly on ensuring an appropriate level of credit to cover positions acquired by market participants in counter flow FTRs. On April 3, 2009, the FERC conditionally approved the second in a series of filings by PJM aimed at reform of its credit policies.[3] The proceeding for compliance with the Commission's conditions is not yet resolved.[4] Effective June 1, 2009, PJM performs weekly rather than monthly billing and payment for the majority of invoice line items, reduced the Unsecured Credit Allowance by two-thirds, eliminated the Unsecured Credit Allowance in support of trading in FTRs, and implemented procedures that allow it to close out and liquidate forward FTR positions held by market participants who have defaulted on their obligations.

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2009 to 2010 Annual FTR Auction was low to moderate for FTR obligations and high for FTR options. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction. In order to provide additional information about the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (MMU) categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. During the 2009 to 2010 planning period, physical entities own 61 percent of prevailing flow Annual FTRs while financial entities own 57 percent of counter flow Annual FTRs. Overall, financial entities own 43 percent of all Annual FTRs. Financial entities own 77 percent of prevailing flow Long Term FTRs and 80 percent of counter flow Long Term FTRs. Financial entities own about 78 percent of all Long Term FTRs. Financial entities own 68 percent of prevailing flow and 82 percent of counter flow Monthly Balance of Planning Period FTRs. Overall, financial entities own 74 percent of all Monthly Balance of Planning Period FTRs.

Market Performance

- **Volume.** The 2010 to 2013 Long Term FTR Auction cleared 86,108 MW (8.1 percent of demand) of FTR buy bids, up from 52,369 MW (6.5 percent) in the 2009 to 2012 Long Term FTR Auction. The 2010 to 2013 Long Term FTR Auction also cleared 5,147 MW (10.0 percent) of FTR sell offers, up from 1,010 MW (6.4 percent) in the 2009 to 2012 Long Term FTR Auction. For the 2009 to 2010 planning period, the Annual FTR Auction cleared 155,612 MW (10.8 percent) of FTR buy bids, down from 204,349 MW (9.4 percent) for the 2008 to 2009 planning period. The Annual FTR Auction also cleared 7,399 MW (5.2 percent) of FTR sell offers for the 2009 to 2010 planning period, up from 4,534 MW (5.4 percent) for the 2008 to 2009 planning period. For the first seven months of the 2009 to 2010 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 568,742 MW (10.7 percent) of FTR buy bids and 177,297 MW (9.0 percent) of FTR sell offers.

3 127 FERC ¶ 61,017. The FERC has approved PJM's proposed revisions to its credit policy in Docket No. ER08-376. 122 FERC ¶ 61,279 (2008).
4 *See* FERC Docket No. ER09-650.

- **Price.** In the 2010 to 2013 Long Term FTR Auction, 93.7 percent of the Long Term FTRs were purchased for less than $1 per MWh and 96.6 percent for less than $2 per MWh. The weighted-average prices paid for Long Term buy-bid FTRs in the 2010 to 2013 Long Term FTR Auction were $0.53 per MWh for 24-hour FTRs, $0.03 per MWh for on peak FTRs and $0.10 per MWh for off peak FTRs. Weighted-average prices paid for Long Term buy-bid FTRs in the 2009 to 2012 Long Term FTR Auction were $0.76 per MWh for 24-hour FTRs, $0.10 per MWh for on peak FTRs and $0.01 per MWh for off peak FTRs. For the 2009 to 2010 planning period, 83.2 percent of the Annual FTRs were purchased for less than $1 per MWh and 90.6 percent for less than $2 per MWh. For the 2009 to 2010 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.66 per MWh for 24-hour FTRs, $0.57 per MWh for on peak FTRs and $0.40 per MWh for off peak FTRs. Weighted-average prices paid for annual buy-bid FTR obligations for the 2008 to 2009 planning period were $1.96 per MWh for 24-hour FTRs and $0.55 per MWh for on peak FTRs and $0.26 per MWh for off peak FTRs. The weighted-average prices paid for 2009 to 2010 planning period annual buy-bid FTR obligations and options were $0.53 per MWh and $0.35 per MWh, respectively, compared to $0.69 per MWh and $0.24 per MWh, respectively, in the 2008 to 2009 planning period.[5] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2009 to 2010 planning period was $0.20 per MWh, compared with $0.30 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2008 to 2009 planning period.

- **Revenue.** The 2010 to 2013 Long Term FTR Auction generated $31.1 million of net revenue for all FTRs, down from $38.9 million in the 2009 to 2012 Long Term FTR Auction. The Annual FTR Auction generated $1,329.8 million of net revenue for all FTRs during the 2009 to 2010 planning period, down from $2,422.6 million for the 2008 to 2009 planning period. The Monthly Balance of Planning Period FTR Auctions generated $13.1 million in net revenue for all FTRs during the first seven months of the 2009 to 2010 planning period.

- **Revenue Adequacy.** FTRs were 100 percent revenue adequate for the 2008 to 2009 planning period. FTRs were paid at 97.7 percent of the target allocation level for the first seven months of the 2009 to 2010 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $388.3 million of FTR revenues during the first seven months of the 2009 to 2010 planning period and $1,748.3 million during the 2008 to 2009 planning period. For the first seven months of the 2009 to 2010 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Mount Storm aggregate, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were the Northern Illinois Hub and the Western Hub, respectively.

5 Weighted-average prices for FTRs in the Long Term FTR Auction, Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the 2009 to 2010 Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,096 hours) and off peak (4,664 hours).

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2009 to 2010 planning period were the AP South Interface and the Electric Junction — Frontenac line. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

- **Demand.** Total demand in the annual ARR allocation was 140,037 MW for the 2009 to 2010 planning period with 64,987 MW bid in Stage 1A, 26,517 MW bid in Stage 1B and 48,533 MW bid in Stage 2. This is down from 140,668 MW for the 2008 to 2009 planning period with 64,546 MW bid in Stage 1A, 27,291 MW bid in Stage 1B and 48,831 MW bid in Stage 2. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 10,531 MW of ARRs associated with approximately $195,300 per MW-day of revenue that were reassigned in the first seven months of the 2009 to 2010 planning period. There were 15,326 MW of ARRs associated with approximately $533,900 per MW-day of revenue that were reassigned for the full 2008 to 2009 planning period.

Market Performance

- **Volume.** Of 140,037 MW in ARR requests for the 2009 to 2010 planning period, 109,413 MW (78.1 percent) were allocated. There were 64,913 MW allocated in Stage 1A, 26,514 MW allocated in Stage 1B and 17,986 MW allocated in Stage 2. Eligible market participants self scheduled 68,589 MW (62.7 percent) of these allocated ARRs as Annual FTRs. Of 140,668 MW in ARR requests for the 2008 to 2009 planning period, 112,011 MW (79.6 percent) were allocated. There were 64,520 MW allocated in Stage 1A, 26,685 MW allocated in Stage 1B and 20,806 MW allocated in Stage 2. Eligible market participants self scheduled 72,851 MW (65.0 percent) of these allocated ARRs as Annual FTRs.

- **Revenue.** As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

- **Revenue Adequacy.** During the 2009 to 2010 planning period, ARR holders will receive \$1,273.5 million in ARR credits, with an average hourly ARR credit of \$1.33 per MWh. During the 2009 to 2010 planning period, the ARR target allocations were \$1,273.5 million while PJM collected \$1,342.9 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 2009, making ARRs revenue adequate. During the 2008 to 2009 planning period, ARR holders received \$2,361.3 million in ARR credits, with an average hourly ARR credit of \$2.41 per MWh. For the 2008 to 2009 planning period, the ARR target allocations were \$2,361.3 million while PJM collected \$2,489.6 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** When ARRs were allocated for the 2009 to 2010 planning period, some of the requested ARRs were prorated in Stage 2 as a result of binding transmission constraints. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints affecting the ARR allocation in these two stages. For the 2008 to 2009 planning period, no ARRs were prorated in Stage 1A of the annual ARR allocation. In Stage 1B, the only constraint affecting the ARR allocation was the Cedar Grove — Clifton line. There were 605.4 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint.

- **ARRs and FTRs as a Hedge against Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The first is to compare the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The second is to compare the congestion revenue received by FTR holders to the costs of those FTRs. The final and comprehensive method is to compare the revenue received by all ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the 2008 to 2009 planning period, all ARRs and FTRs hedged more than 100 percent of the congestion costs within PJM. During the first seven months of the 2009 to 2010 planning period, total ARR and FTR revenues hedged 93.5 percent of the congestion costs within PJM.

- **ARRs and FTRs as a Hedge against Total Energy Costs.** The hedge provided by ARRs can also be measured by comparing the value of the ARR and self-scheduled FTRs that sink in a zone to the cost of real time energy in the zone. This is a measure of the value of the hedge against real time energy costs provided by ARRs received by loads during this period. The total value of ARRs was 3.5 percent of the total real time energy charges in calendar year 2009. The hedge provided by FTRs can also be measured by comparing the value of the FTRs that sink in a zone to the cost of real time energy in the zone. The total net value of FTRs was -0.9 percent of the total real time energy charges in calendar year 2009 because the purchase cost exceeded the value of the credits. When combined, the sum is a measure of the total value of ARRs plus FTRs. The total value of ARRs plus FTRs was 2.6 percent of the total real time energy charges in calendar year 2009.

Conclusion

The annual ARR allocation and the FTR auctions provide market participants with hedging instruments. These instruments can be used for hedging positions or for speculation. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR

Auctions provide a market valuation of FTRs. The FTR auction results for the 2009 to 2010 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. This would include both FTRs that are directly self scheduled and FTRs on paths identical to the ARR, which are financially equivalent to self scheduled FTRs. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. The underlying FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches.

ARRs were 100 percent revenue adequate for both the 2008 to 2009 and the 2009 to 2010 planning periods. FTRs were paid at 100 percent of the target allocation level for the 12-month period of the 2008 to 2009 planning period, and at 97.7 percent of the target allocation level for the first seven months of the 2009 to 2010 planning period. Revenue adequacy for a planning period is not final until the end of the period.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to the costs of purchasing the FTRs. For the 2008 to 2009 planning period the total cost of all FTRs exceeded the FTR credits received, based on the value of the congestion costs for which they were purchased as a hedge. After the cost to obtain the FTRs was subtracted from the total FTR revenue, the net value of all FTRs was negative and thus the FTRs were unprofitable.The total of ARR and FTR revenues hedged more than 100 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2008 to 2009 planning period and 93.5 percent of the congestion costs in PJM for the first seven months of the 2009 to 2010 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.

Financial Transmission Rights

While FTRs have been available to eligible participants since the 1998 introduction of LMP, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. Since the 2006 to 2007 planning period, the auction has covered all control zones.

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[6] The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs,

6 For additional information on marginal losses, see the *2009 State of the Market Report for PJM*, Volume II, Section 2, “Energy Market, Part 1,” at “Real-Time Annual LMP Loss Component.”

control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation represents what the holders would receive if sufficient revenues are collected to fund FTRs.

Depending on the amount of FTR revenues collected, FTR holders with a positively valued FTR may receive congestion credits between zero and their target allocations. FTR holders with a negatively valued FTR are required to pay charges equal to their target allocations. When FTR holders receive their target allocations, the associated FTRs are fully funded. The objective function of all FTR auctions is to maximize the bid-based value of FTRs awarded in each auction.

FTRs can be bought, sold and self scheduled. Buy bids are FTRs that are bought in the auctions; sell offers are existing FTRs that are sold in the auctions; and self scheduled bids are FTRs that have been directly converted from ARRs.

There are two FTR hedge type products: obligations and options. An obligation provides a credit, positive or negative, equal to the product of the FTR MW and the congestion price difference between FTR sink (destination) and source (origin) that occurs in the Day-Ahead Energy Market. An option provides only positive credits and options are available for only a subset of the possible FTR transmission paths.

There are three FTR class type products: 24-hour, on peak and off peak. The 24-hour products are effective 24 hours a day, seven days a week, while the on peak products are effective during on peak periods defined as the hours ending 0800 through 2300, Eastern Prevailing Time (EPT) Mondays through Fridays, excluding North American Electric Reliability Council (NERC) holidays. The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

FTR buy bids and sell offers may be made as obligations or options and as any of the three class types. FTR self scheduled bids are available only as obligations and 24-hour class types, consistent with the associated ARRs.

Market Structure

Prior to implementation of the Annual FTR Auction, only network service and long-term, firm, point-to-point transmission service customers were able to directly obtain Annual FTRs. Now all transmission service customers and PJM members can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Supply

Throughout the year, PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[7] The Annual FTR Auction includes the ability to directly convert allocated ARRs into self scheduled FTRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included, while known outages of five days or more are included for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[8] But, the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may not be planned in advance or may be emergency in nature. FTRs can be traded between market participants through bilateral transactions.

During the 2009 to 2010 planning period, binding transmission constraints prevented the award of all requested FTRs in the Long Term FTR Auction, the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions.[9] Table 8-1 and Table 8-2 list the top 10 binding constraints along with their corresponding control zones in the Long Term FTR Auction and the Annual FTR Auction, respectively. They are listed in order of severity, irrespective of auction round. For each of the top 10 binding constraints, a numerical ranking in order of severity for each auction round is also listed. The order of severity is determined by the marginal value of the binding constraint. The marginal value measures the value gained by relieving a constraint by 1 MW. The marginal value is computed and generated in the optimization engine for both on peak and off peak hours.[10] Table 8-1 and Table 8-2 demonstrate the marginal value for on peak hours only.

Table 8-1 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2010 to 2013[11]

			Severity Ranking by Auction Round	
Constraint	Type	Control Zone	1	2
Carroll	Transformer	AP	1	NA
Philipsburg - Shawville	Line	PENELEC	21	1
Smith - Wylie Ridge	Line	AP	NA	2
Oak Grove - Galesburg	Flowgate	External	2	3
MECS - IMO	Flowgate	External	46	4
Arnold - Hazleton	Flowgate	External	52	5
Roxbury - Shade Gap	Line	PENELEC	3	8
Doubs - Mount Storm	Line	500	4	19
Bull Run - Volunteer	Line	AEP	5	58
Branchburg - Ramapo	Line	PSEG	6	25

7 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 38.
8 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 54.
9 Binding constraints for Monthly Balance of Planning Period Auctions are posted to the PJM website in monthly files at <http://www.pjm.com/markets-and-operations/ftr/auction-user-info/historical-ftr-auction.aspx>.
10 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 57.
11 The transmission facilities that were not constrained during a certain auction round are listed as NA (not applicable).

Table 8-2 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2009 to 2010

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
AP South	Interface	AP	1	1	1	1
Mahans Lane - Tidd	Line	AEP	2	3	2	2
Albright - Mt. Zion	Line	AP	36	2	7	13
Kingwood - Pruntytown	Line	AP	22	4	3	5
Mount Storm - Pruntytown	Line	AP	3	6	4	4
Pana North	Flowgate	External	8	5	6	3
Mt. Jackson - Edinburg	Line	Dominion	4	7	9	6
Monroe - Shieldalloy	Line	AECO	5	10	8	7
Tiltonsville - Windsor	Line	AP	9	9	5	8
Keisters - Campbell OE	Flowgate	External	10	8	45	166

Long Term FTR Auction

During the 2008 to 2009 planning period, a new Long Term FTR Auction was introduced.[12] PJM conducts a Long Term FTR Auction for the three consecutive planning periods immediately following the planning period during which the Long Term FTR Auction is conducted. The capacity offered for sale in Long Term FTR Auctions is the residual system capability after the assumption that all ARRs allocated in the immediately prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The Long Term FTR Auction consists of two rounds. In each round 50 percent of the feasible FTR available capability is awarded.[13]

- **Round 1.** The first round is conducted approximately 11 months prior to the start of the term covered by the Long Term FTR Auction. Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- **Round 2.** The second round is conducted approximately 4 months after the first round.[14] FTRs purchased in the first round may be offered for sale in the second round.

FTRs obtained in the Long Term Auctions may have terms of one year or a term of three years.

12 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Open Access Transmission Tariff and the Amended and Restated Operating Agreement pursuant to Section 205 of the Federal Power Act. The proposed revisions modify the FTR auction rules in the PJM Interchange Energy Market by establishing a Long Term FTR Auction process, Docket No. ER08-1016-000, (May 28, 2008).

13 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 38.

14 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 42.

Annual FTR Auction

Each April, PJM conducts an Annual FTR Auction during which all eligible market participants may bid on FTRs for the next planning period consistent with total transmission system capability, excluding the FTRs approved in prior Long Term FTR Auctions. The auction takes place over four rounds with 25 percent of the feasible transmission system capability awarded in each round:

- **Round 1.** Market participants make offers for FTRs between any source and sink. These offers can be 24-hour, on peak or off peak FTR obligations or FTR options. Locational prices are determined by maximizing the net revenue based on offer-based value of FTRs.[15] Any transmission service customer or PJM member can bid for available FTRs. ARR holders wishing to directly convert their previously allocated ARRs into self scheduled FTRs must initiate that process in this round. One quarter of each self scheduled FTR clears as a 24-hour FTR in each of the four rounds. Self scheduled FTRs must have the same source and sink as the corresponding ARR. Self scheduled FTRs clear as price-taking FTR bids that are not eligible to set auction price.

- **Rounds 2 to 4.** Market participants make offers for FTRs. Locational prices are determined by maximizing the offer-based value of FTRs cleared. FTRs purchased in earlier rounds can be offered for sale in later rounds.

By self scheduling ARRs as price-taking bids in the Annual FTR Auction, customers with ARRs receive FTRs for their ARR paths. ARR holders are guaranteed that they will receive their requested FTRs. ARRs can be self scheduled only as 24-hour FTR obligations. ARR holders that self schedule ARRs as FTRs still hold the associated ARR. Self scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue based on holding the ARR and is left with ownership of the FTR as a hedge. The following is an illustrative example of self scheduling ARRs as FTRs. An ARR holder has received an allocation of 1 MW from source A to sink B. The ARR holder self schedules the 1 MW allocated ARR as an FTR. In the Annual FTR Auction, the price for a 1 MW FTR from A to B is $100. The ARR holder pays $100 to buy the 1 MW FTR in the Annual FTR Auction, but receives a $100 ARR target credit based on the associated 1 MW ARR. In addition, the ARR holder obtains the corresponding FTR target allocation as a hedge.

Monthly Balance of Planning Period FTR Auctions

The Monthly Balance of Planning Period FTR Auctions make available the residual FTR capability on the PJM transmission system after the Long Term and Annual FTR Auctions are concluded. They are single-round monthly auctions that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. Market participants can bid for or offer monthly FTRs for any of the next three months remaining in the planning period, or quarterly FTRs for any of the quarters remaining in the balance of the planning period. FTRs in the auctions can be either obligations or options and can be 24-hour, on peak or off peak products.[16]

15 Long Term, Annual and Monthly Balance of Planning Period FTR Auctions determine nodal prices as a function of market participants' FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces maximum net revenue, thus maximizing the value of transmission assets. A feasible set of FTR bids is a set that does not impose a flow on any transmission facility in excess of its rating.

16 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 39.

Under the auction rules, market participants may bid to buy or offer to sell FTRs that have the following two terms. The first term is for one month for any of the next three months remaining in the planning period. For example, if the auction is conducted in May, any FTR valid for the months of June, July and August is included in the auction. The second term is for three months for any of the quarters remaining in the planning period (if technically feasible within the specified market time frame). For example, for planning period quarter 1 (Q1), the auction period would be June, July and August. For planning period quarter 2 (Q2), the auction period would be September, October and November. Similarly, December, January and February would be for planning period quarter 3 (Q3) and March, April and May would be for planning period quarter 4 (Q4). For example, an auction held in May would have all four quarters available, while an auction held in June would include quarter 2, quarter 3 and quarter 4, but not quarter 1.

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM-administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions that are done outside of PJM's secondary bilateral market system.

For bilateral trades done through PJM, the FTR transmission path must remain the same; FTR obligations must remain obligations and FTR options must remain options. However, an individual FTR may be split up into multiple, smaller FTRs, down to increments of 0.1 MW. FTRs can also be given different start and end times, but the start time cannot be earlier than the original FTR start time and the end time cannot be later than the original FTR end time.

Demand

Under current rules, participants may submit unlimited bids for FTRs for any single auction round in the Annual FTR Auction or for any single Monthly Balance of Planning Period FTR Auction.

FTR Credit Issues

Default

One participant defaulted for a small amount, which was covered by collateral, in 2009, and one participant had losses on annual FTRs that extended into 2009. PJM made multiple filings in 2008 and 2009 to reform its credit policies, focusing particularly on ensuring an appropriate level of credit to cover positions acquired by market participants in counter flow FTRs. On April 3, 2009, the FERC conditionally approved the second in a series of filings by PJM aimed at reform of its credit policies.[17] Effective June 1, 2009, PJM performs weekly rather than monthly billing for the majority of invoice line items, reduced the unsecured credit allowance by two-thirds, eliminated the Unsecured Credit Allowance in support of trading in FTRs, and implemented procedures that allow

17 127 FERC ¶ 61,017. In 2008, the FERC approved a number of PJM's earlier revisions. 122 FERC ¶ 61,279.

it to close out and liquidate forward FTR positions held by market participants who have defaulted on their obligations.

Prevailing flow FTRs hedge congestion on a path. Participants purchase prevailing flow FTRs for a positive price with the expectation that the FTR revenues will exceed the cost of the FTRs. Counter flow FTRs expose the owner to paying congestion on a path. Participants receive a payment to take counter flow FTRs with the expectation that the payment will exceed the FTR charges they must pay. The risk of a prevailing flow FTR is generally limited to the purchase price, although risk could increase if congestion reversed. The risk of a counter flow FTR derives from the underlying congestion and is, therefore, not limited to a fixed payment. The risk is substantially greater for a counter flow FTR than for a prevailing flow FTR.

FTR Credit Rules

In response to a series of high profile defaults, PJM began in 2007 an effort to reform its credit policies that continued into 2009.[18] On February 3, 2009, PJM proposed tariff revisions that would reduce the per member allowance of unsecured credit by two thirds, limit the unsecured credit allowance for a family of affiliates to an aggregate $150 million, eliminate unsecured credit allowances for FTR trading activity, shorten settlement periods by transitioning to weekly from monthly billing for invoice line items that represent most of PJM's billings, and allow PJM to close and liquidate a member's FTR positions after a declaration of that member's default.[19]

By order issued April 3, 2009, the Commission accepted PJM's revisions subject to conditions.[20] The provisions concerning the FTR market, including the elimination of unsecured credit in those markets, became effective April 6, 2009.[21] The Commission conditioned its approval on PJM's filing and justifying revisions to allow appropriate collateral reductions for LSEs having physical assets that reduce the risk of default. PJM filed revisions on May 4, 2009, proposing to (i) allow 25 percent of current planning year ARR credits to offset each planning year's undiversified credit requirement in the Long Term FTR auctions and (ii) qualify the definition and calculation of "FTR Portfolio Auction Value" to exclude negatively priced FTRs that sink at such an LSE's location (as determined from the effective ARR allocation) and to require that the MW quantity of FTRs not exceed the peak load of the LSE at each location.[22] The Commission found PJM's filing deficient, and requested responses to questions by letter dated October 8, 2009. PJM responded in a submittal dated November 9, 2009. Further action on PJM's filing is now pending before the FERC.

The MMU supports PJM's actions to reduce unsecured credit including the elimination of unsecured credit in PJM's FTR markets. The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.[23]

18 See the *2008 State of the Market Report for PJM* at 393 through 395 for discussion of reforms made effective in 2007 through 2008.
19 PJM filed proposed revisions to Attachment Q in Docket No. ER09-650-000.
20 127 FERC ¶61,017.
21 *Id.* at 30.
22 PJM Compliance filing in ER09-650-002 at 3–4.
23 PJM has indicated, as part of its Counterparty Initiative, that its ability to assert claims for deficiencies in a bankruptcy proceeding may be further compromised by its current lack of privity in such transactions insofar as this affects the ability to net credits and charges. *See*, *e.g.*, presentation of Suzanne Daugherty and Vincent Duane to the October 22, 2009 meeting of the PJM Tariff Advisory Committee, "Counterparty Initiative—Follow-up Items from First Information Session", which can be accessed at the following link: <http://www.pjm.com/~/media/committees-groups/committees/tac/20091022/20091022-item-02a-counterparty-initiative-second-information-session.ashx>.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counter flow FTRs is descriptive and is not necessarily a measure of actual or potential FTR market structure issues, as the ownership positions result from competitive auctions. The percentage of FTR ownership shares may change when FTR owners buy or sell FTRs in the Monthly Balance of Planning Period FTR Auctions or secondary bilateral market.

The ownership concentration of cleared FTR buy bids resulting from the 2009 to 2010 Annual FTR Auction was low to moderate for FTR obligations and high for FTR options.

For cleared FTR buy-bid obligations in the 2009 to 2010 Annual FTR Auction, the HHIs were 1038 for 24-hour, 821 for on peak and 835 for off peak FTR products while maximum market shares were 20 percent for 24-hour, which is associated with a physical entity, 14 percent for on peak, which is associated with a financial entity, and 13 percent for off peak FTR products, which is associated with a financial entity.

For cleared FTR buy-bid options in the 2009 to 2010 Annual FTR Auction, HHIs were 4399 for 24-hour, 1868 for on peak and 2040 for off peak products while maximum market shares were 58 percent for 24-hour, which is associated with a physical entity, 27 percent for on peak, which is associated with a financial entity, and 31 percent for off peak FTR products, which is associated with a financial entity.

In order to evaluate the ownership of prevailing flow and counter flow FTRs, the MMU categorized all participants owning FTRs in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. International market participants that primarily take financial positions in PJM markets are generally considered to be financial entities even if they are utilities in their own countries.

Table 8-3 presents the 2010 to 2013 Long Term FTR Auction market cleared FTRs by organization type and FTR direction. The results show that financial entities own 77 percent of prevailing flow FTRs and 80 percent of counter flow FTRs. Overall, financial entities own about 78 percent of all Long Term FTRs.

Table 8-3 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2010 to 2013

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	23.3%	20.4%	22.0%
Financial	76.7%	79.6%	78.0%
Total	100.0%	100.0%	100.0%

Table 8-4 presents the Annual FTR Auction market cleared FTRs in the 2009 to 2010 planning period by organization type and FTR direction. The results show that physical entities own 61 percent of prevailing flow FTRs while financial entities own 57 percent counter flow FTRs. Overall, financial entities own about 43 percent of all Annual FTRs.

Table 8-4 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2009 to 2010

		FTR Direction		
Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Physical	Yes	36.7%	5.9%	29.6%
	No	24.4%	36.8%	27.3%
	Total	61.2%	42.7%	56.9%
Financial	No	38.8%	57.3%	43.1%
Total		100.0%	100.0%	100.0%

Table 8-5 presents the Monthly Balance of Planning Period FTR Auction market cleared FTRs in calendar year 2009 by organization type and FTR direction. The results show that financial entities own 68 percent of prevailing flow FTRs and 82 percent of counter flow FTRs. Overall, financial entities own 74 percent of all Monthly Balance of Planning Period FTRs.

Table 8-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: Calendar year 2009

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	32.3%	18.2%	26.3%
Financial	67.7%	81.8%	73.7%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-6 shows the 2010 to 2013 Long Term FTR Auction volume by trade type, FTR direction and period type.[24] The total volume was 1,064,620 MW for FTR buy bids and 51,582 MW for FTR sell offers in the 2010 to 2013 Long Term FTR Auction. This is up from the total volume of 803,911 MW for FTR buy bids and 15,757 MW for FTR sell offers in the 2009 to 2012 Long Term FTR Auction.

The 2010 to 2013 Long Term FTR Auction cleared 86,108 MW (8.1 percent) leaving 978,513 MW (91.9 percent) of uncleared FTR buy bids. There were 5,147 MW (10.0 percent) of cleared FTR sell offers leaving 46,435 MW (90.0 percent) of uncleared FTR sell offers. This is up from the total of 52,369 MW (6.5 percent) of cleared FTR buy bids and 1,010 MW (6.4 percent) of cleared FTR sell offers in the 2009 to 2012 Long Term FTR Auction.

In the 2010 to 2013 Long Term FTR Auction, there were 38,000 MW (14.0 percent) cleared out of 271,944 MW counter flow FTR buy bids and 48,108 MW (6.1 percent) cleared out of 792,676 MW prevailing flow FTR buy bids. In the 2010 to 2013 Long Term FTR Auction, there were 2,225 MW

24 Calculated values shown in Section 8, "Financial Transmission and Auction Revenue Rights," are based on unrounded, underlying data and may differ from calculations based on the rounded values in the tables.

(13.7 percent) cleared out of 16,210 MW counter flow FTR sell offers and 2,922 MW (8.3 percent) cleared out of 35,373 MW prevailing flow FTR offers.

Table 8-6 Long Term FTR Auction market volume: Planning periods 2010 to 2013

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	34,672	129,869	17,627	13.6%	112,241	86.4%
		Year 2	15,258	93,733	9,849	10.5%	83,884	89.5%
		Year 3	12,569	47,954	10,517	21.9%	37,437	78.1%
		Year All	25	389	7	1.7%	382	98.3%
		Total	62,524	271,944	38,000	14.0%	233,944	86.0%
	Prevailing Flow	Year 1	68,326	313,683	17,779	5.7%	295,904	94.3%
		Year 2	49,950	252,781	15,206	6.0%	237,574	94.0%
		Year 3	43,037	226,172	15,102	6.7%	211,070	93.3%
		Year All	7	40	20	50.0%	20	50.0%
		Total	161,320	792,676	48,108	6.1%	744,568	93.9%
	Total		223,844	1,064,620	86,108	8.1%	978,513	91.9%
Sell offers	Counter Flow	Year 1	2,503	7,800	1,473	18.9%	6,327	81.1%
		Year 2	1,468	5,190	727	14.0%	4,462	86.0%
		Year 3	1,032	3,220	25	0.8%	3,195	99.2%
		Year All	NA	NA	NA	NA	NA	NA
		Total	5,003	16,210	2,225	13.7%	13,985	86.3%
	Prevailing Flow	Year 1	4,445	17,211	1,552	9.0%	15,659	91.0%
		Year 2	3,367	13,294	1,191	9.0%	12,103	91.0%
		Year 3	1,267	4,868	179	3.7%	4,689	96.3%
		Year All	NA	NA	NA	NA	NA	NA
		Total	9,079	35,373	2,922	8.3%	32,451	91.7%
	Total		14,082	51,582	5,147	10.0%	46,435	90.0%

Table 8-7 shows the Annual FTR Auction volume by trade type, hedge type and FTR direction for the 2009 to 2010 planning period. The total volume was 1,436,335 MW for FTR buy bids and 142,154 MW for FTR sell offers for the 2009 to 2010 planning period. This is down from the total volume of 2,181,273 MW for FTR buy bids and up from 83,453 MW for FTR sell offers for the 2008 to 2009 planning period.

There were 155,612 MW (10.8 percent) of cleared FTR buy bids and 7,399 MW (5.2 percent) of cleared FTR sell offers for the 2009 to 2010 planning period. This is down from the total of 204,349 MW (9.4 percent) of cleared FTR buy bids and up from 4,534 MW (5.4 percent) of cleared FTR sell offers for the 2008 to 2009 planning period.

For the 2009 to 2010 planning period, there were 48,017 MW (15.6 percent) cleared out of 307,750 MW counter flow FTR buy bids and 107,595 MW (9.5 percent) cleared out of 1,128,585 MW prevailing flow FTR buy bids. During the 2009 to 2010 planning period, there were 2,390 MW (5.3 percent) cleared out of 44,772 MW counter flow FTR sell offers and 5,009 MW (5.1 percent) cleared out of 97,381 MW prevailing flow FTR offers.

Table 8-7 Annual FTR Auction market volume: Planning period 2009 to 2010

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	80,464	304,889	45,356	14.9%	259,533	85.1%
		Prevailing Flow	179,814	986,613	84,161	8.5%	902,452	91.5%
		Total	260,278	1,291,502	129,517	10.0%	1,161,985	90.0%
	Options	Counter Flow	26	2,861	2,661	93.0%	200	7.0%
		Prevailing Flow	6,242	141,972	23,433	16.5%	118,538	83.5%
		Total	6,268	144,833	26,095	18.0%	118,738	82.0%
	Total	Counter Flow	80,490	307,750	48,017	15.6%	259,733	84.4%
		Prevailing Flow	186,056	1,128,585	107,595	9.5%	1,020,990	90.5%
		Total	266,546	1,436,335	155,612	10.8%	1,280,723	89.2%
Self-scheduled bids	Obligations	Counter Flow	620	3,175	3,175	100.0%	0	0.0%
		Prevailing Flow	8,796	65,414	65,414	100.0%	0	0.0%
		Total	9,416	68,589	68,589	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	81,084	308,064	48,531	15.8%	259,533	84.2%
		Prevailing Flow	188,610	1,052,027	149,576	14.2%	902,452	85.8%
		Total	269,694	1,360,091	198,107	14.6%	1,161,985	85.4%
	Options	Counter Flow	26	2,861	2,661	93.0%	200	7.0%
		Prevailing Flow	6,242	141,972	23,433	16.5%	118,538	83.5%
		Total	6,268	144,833	26,095	18.0%	118,738	82.0%
	Total	Counter Flow	81,110	310,925	51,192	16.5%	259,733	83.5%
		Prevailing Flow	194,852	1,193,999	173,009	14.5%	1,020,990	85.5%
		Total	275,962	1,504,924	224,201	14.9%	1,280,723	85.1%
Sell offers	Obligations	Counter Flow	13,789	42,950	2,390	5.6%	40,560	94.4%
		Prevailing Flow	21,608	83,797	4,869	5.8%	78,929	94.2%
		Total	35,397	126,747	7,259	5.7%	119,489	94.3%
	Options	Counter Flow	19	1,822	0	0.0%	1,822	100.0%
		Prevailing Flow	940	13,584	140	1.0%	13,444	99.0%
		Total	959	15,406	140	0.9%	15,266	99.1%
	Total	Counter Flow	13,808	44,772	2,390	5.3%	42,382	94.7%
		Prevailing Flow	22,548	97,381	5,009	5.1%	92,372	94.9%
		Total	36,356	142,154	7,399	5.2%	134,755	94.8%

Table 8-8 shows that for the 2009 to 2010 planning period, eligible market participants converted 68,589 MW of ARRs out of a possible 109,413 MW into Annual FTRs. In comparison, during the 2008 to 2009 planning period, eligible market participants converted 72,851 MW of ARRs out of a possible 112,011 MW.

Table 8-8 Comparison of self scheduled FTRs: Planning periods 2008 to 2009 and 2009 to 2010

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2008/2009	72,851	112,011	65.0%
2009/2010	68,589	109,413	62.7%

Table 8-9 shows that there were 5,166,634 MW of FTR buy bid obligations and 1,621,113 MW of FTR sell offer obligations for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2009 to 2010 planning period through December 31, 2009. The monthly auctions cleared 555,727 MW (10.8 percent) leaving 4,610,907 MW (89.2 percent) of uncleared FTR buy bid obligations. There were 129,451 MW (8.0 percent) of cleared FTR sell offer obligations leaving 1,491,662 MW (92.0 percent) of uncleared FTR sell offer obligations.

There were 173,184 MW of FTR buy bid options and 341,723 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2009 to 2010 planning period through December 31, 2009. The monthly auctions cleared 13,015 MW (7.5 percent) leaving 160,169 MW (92.5 percent) of uncleared FTR buy bid options. There were 47,846 MW (14.0 percent) of cleared FTR sell offer options leaving 293,878 MW (86.0 percent) of uncleared FTR sell offer options.

The Monthly Balance of Planning Period FTR Auctions for the full 12-month 2008 to 2009 planning period had a total demand of 10,223,437 MW for FTR buy bids and 2,172,401 MW for FTR sell offers. The monthly auctions cleared 804,215 MW (7.9 percent) of FTR buy bids and 258,747 MW (11.9 percent) of FTR sell offers.

Table 8-9 Monthly Balance of Planning Period FTR Auction market volume: Calendar year 2009

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-09	Obligations	Buy bids	166,943	648,482	59,472	9.2%	589,011	90.8%
		Sell offers	36,552	172,413	17,489	10.1%	154,924	89.9%
	Options	Buy bids	473	25,043	3,628	14.5%	21,415	85.5%
		Sell offers	475	13,010	1,871	14.4%	11,139	85.6%
Feb-09	Obligations	Buy bids	167,297	613,252	54,064	8.8%	559,188	91.2%
		Sell offers	33,278	135,132	13,663	10.1%	121,469	89.9%
	Options	Buy bids	1,000	26,021	1,408	5.4%	24,613	94.6%
		Sell offers	399	11,925	1,370	11.5%	10,555	88.5%
Mar-09	Obligations	Buy bids	153,613	542,094	54,409	10.0%	487,685	90.0%
		Sell offers	43,579	176,838	14,931	8.4%	161,907	91.6%
	Options	Buy bids	738	38,982	4,626	11.9%	34,356	88.1%
		Sell offers	472	12,300	1,382	11.2%	10,918	88.8%
Apr-09	Obligations	Buy bids	121,034	417,636	49,603	11.9%	368,034	88.1%
		Sell offers	31,574	131,945	12,924	9.8%	119,021	90.2%
	Options	Buy bids	204	22,992	614	2.7%	22,379	97.3%
		Sell offers	353	8,776	1,607	18.3%	7,168	81.7%
May-09	Obligations	Buy bids	79,272	285,448	31,020	10.9%	254,428	89.1%
		Sell offers	19,030	70,521	8,843	12.5%	61,678	87.5%
	Options	Buy bids	131	9,750	183	1.9%	9,567	98.1%
		Sell offers	195	2,585	1,345	52.0%	1,240	48.0%
Jun-09	Obligations	Buy bids	202,097	807,023	72,951	9.0%	734,073	91.0%
		Sell offers	79,699	276,795	24,514	8.9%	252,281	91.1%
	Options	Buy bids	734	40,968	2,552	6.2%	38,416	93.8%
		Sell offers	5,377	69,781	11,567	16.6%	58,214	83.4%
Jul-09	Obligations	Buy bids	196,831	802,217	67,977	8.5%	734,240	91.5%
		Sell offers	79,359	300,588	22,533	7.5%	278,055	92.5%
	Options	Buy bids	547	47,525	2,954	6.2%	44,570	93.8%
		Sell offers	4,264	60,406	7,011	11.6%	53,396	88.4%
Aug-09	Obligations	Buy bids	202,379	702,162	76,065	10.8%	626,096	89.2%
		Sell offers	70,434	245,516	17,981	7.3%	227,535	92.7%
	Options	Buy bids	101	6,290	1,287	20.5%	5,003	79.5%
		Sell offers	3,264	48,784	4,111	8.4%	44,673	91.6%
Sep-09	Obligations	Buy bids	173,626	681,422	79,711	11.7%	601,711	88.3%
		Sell offers	67,180	237,135	18,347	7.7%	218,788	92.3%
	Options	Buy bids	474	36,824	2,180	5.9%	34,644	94.1%
		Sell offers	3,565	53,891	6,546	12.1%	47,345	87.9%
Oct-09	Obligations	Buy bids	198,431	783,022	85,207	10.9%	697,815	89.1%
		Sell offers	62,543	216,852	15,759	7.3%	201,093	92.7%
	Options	Buy bids	293	14,047	1,317	9.4%	12,730	90.6%
		Sell offers	2,529	41,741	6,436	15.4%	35,305	84.6%
Nov-09	Obligations	Buy bids	184,294	729,780	82,710	11.3%	647,070	88.7%
		Sell offers	46,896	155,974	12,043	7.7%	143,931	92.3%
	Options	Buy bids	463	15,553	1,679	10.8%	13,874	89.2%
		Sell offers	1,943	29,609	6,769	22.9%	22,840	77.1%
Dec-09	Obligations	Buy bids	157,014	661,008	91,106	13.8%	569,902	86.2%
		Sell offers	52,471	188,253	18,275	9.7%	169,978	90.3%
	Options	Buy bids	367	11,978	1,046	8.7%	10,932	91.3%
		Sell offers	2,278	37,512	5,407	14.4%	32,105	85.6%
2008/2009*	Obligations	Buy bids	2,143,034	9,449,644	782,007	8.3%	8,667,637	91.7%
		Sell offers	504,152	1,991,496	226,544	11.4%	1,764,952	88.6%
	Options	Buy bids	11,754	773,793	22,209	2.9%	751,584	97.1%
		Sell offers	6,550	180,904	32,203	17.8%	148,701	82.2%
2009/2010**	Obligations	Buy bids	1,314,672	5,166,634	555,727	10.8%	4,610,907	89.2%
		Sell offers	458,582	1,621,113	129,451	8.0%	1,491,662	92.0%
	Options	Buy bids	2,979	173,184	13,015	7.5%	160,169	92.5%
		Sell offers	23,220	341,723	47,846	14.0%	293,878	86.0%

* Shows Twelve Months for 2008/2009; ** Shows seven months ended 31-Dec-2009 for 2009/2010

Table 8-10 shows the bid and cleared volume for FTR buy bids in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2009 through December 2009.

Table 8-10 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): Calendar year 2009

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-09	Bid	299,268	129,139	99,968				145,151	673,525
	Cleared	41,932	9,425	3,985				7,758	63,100
Feb-09	Bid	311,274	106,999	93,220				127,781	639,274
	Cleared	37,183	6,216	5,347				6,727	55,472
Mar-09	Bid	305,146	120,085	115,103				40,741	581,075
	Cleared	41,859	8,073	6,687				2,415	59,034
Apr-09	Bid	306,763	133,866						440,629
	Cleared	41,884	8,332						50,216
May-09	Bid	295,198							295,198
	Cleared	31,204							31,204
Jun-09	Bid	283,451	121,774	119,403	24,320	104,418	102,266	92,358	847,992
	Cleared	33,822	9,100	8,599	2,500	7,967	7,524	5,991	75,503
Jul-09	Bid	306,644	133,812	95,573		100,333	107,062	106,318	849,742
	Cleared	38,785	8,346	3,991		5,869	6,325	7,615	70,932
Aug-09	Bid	314,301	85,842	75,477		69,309	79,140	84,383	708,452
	Cleared	47,960	6,627	6,057		4,214	5,276	7,219	77,353
Sep-09	Bid	342,826	89,939	86,533		22,245	90,764	85,939	718,246
	Cleared	52,579	7,095	6,539		2,150	6,268	7,260	81,891
Oct-09	Bid	464,697	91,286	76,482			85,335	79,268	797,069
	Cleared	58,957	9,039	5,096			6,019	7,413	86,524
Nov-09	Bid	409,943	78,942	76,920			96,707	82,822	745,333
	Cleared	57,249	5,494	6,121			7,423	8,102	84,389
Dec-09	Bid	351,985	101,436	98,036			24,867	96,662	672,986
	Cleared	55,233	10,906	9,364			3,379	13,269	92,152

Table 8-11 shows the secondary bilateral FTR market volume and weighted-average cleared prices by hedge type and class type for the 2008 to 2009 and the 2009 to 2010 planning periods. There were 1,643 MW of total bilateral FTR activity for the 2009 to 2010 planning period through December 31, 2009 while there were 1,948 MW during the 2008 to 2009 planning period. During the 2009 to 2010 planning period through December 31, 2009, the weighted-average prices of bilateral FTR obligations and options were $0.37 per MWh and $5.93 per MWh, respectively. Comparable weighted-average prices were $0.59 per MWh for bilateral FTR obligations and $6.25 per MWh for bilateral FTR options for the 2008 to 2009 planning period.

Table 8-11 Secondary bilateral FTR market volume and weighted-average cleared prices (Dollars per MWh): Planning periods 2008 to 2009 and 2009 to 2010[25]

Planning Period	Hedge Type	Class Type	Volume (MW)	Price
2008/2009	Obligation	24-Hour	800	$0.46
		On Peak	1,133	$1.14
		Off Peak	9	$0.84
		Total	1,942	$0.59
	Option	24-Hour	0	NA
		On Peak	6	$6.25
		Off Peak	0	NA
		Total	6	$6.25
2009/2010*	Obligation	24-Hour	1,468	$0.38
		On Peak	20	($0.23)
		Off Peak	125	($1.79)
		Total	1,613	$0.37
	Option	24-Hour	30	$5.93
		On Peak	0	NA
		Off Peak	0	NA
		Total	30	$5.93

* Shows seven months ended 31-Dec-2009

Price

Table 8-12 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2010 to 2013 Long Term FTR Auction. Only FTR obligation products are available in Long Term FTR Auctions. In this auction, weighted-average, buy-bid FTR prices were $0.10 per MWh while weighted-average sell offer FTR prices were $0.35 per MWh. Comparable weighted-average, buy-bid FTR prices were $0.16 per MWh while weighted-average sell offer FTR prices were $0.29 per MWh in the 2009 to 2012 Long Term FTR Auction.

25 The 2009 to 2010 planning period covers the 2009 to 2010 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through the December 2009 FTR Auction.

Table 8-12 Long Term FTR Auction weighted-average cleared prices (Dollars per MWh): Planning periods 2010 to 2013

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.62)	($0.32)	($0.46)	($0.54)
		Year 2	($2.48)	($0.38)	($0.50)	($0.58)
		Year 3	($2.34)	($0.24)	($0.36)	($0.38)
		Year All	($1.80)	NA	NA	($1.80)
		Total	($1.88)	($0.31)	($0.44)	($0.51)
	Prevailing Flow	Year 1	$3.16	$0.40	$0.62	$0.73
		Year 2	$3.35	$0.25	$0.44	$0.56
		Year 3	$2.19	$0.27	$0.38	$0.43
		Year All	$3.91	$2.62	$5.37	$3.64
		Total	$3.00	$0.31	$0.49	$0.59
	Total		$0.53	$0.03	$0.10	$0.10
Sell offers	Counter Flow	Year 1	($0.18)	($0.02)	($0.03)	($0.02)
		Year 2	NA	($0.01)	($0.01)	($0.01)
		Year 3	NA	($0.09)	($0.09)	($0.09)
		Year All	NA	NA	NA	NA
		Total	($0.18)	($0.02)	($0.03)	($0.02)
	Prevailing Flow	Year 1	$0.51	$0.39	$0.66	$0.55
		Year 2	NA	$0.50	$1.06	$0.78
		Year 3	NA	$0.69	$0.47	$0.57
		Year All	NA	NA	NA	NA
		Total	$0.51	$0.46	$0.80	$0.64
	Total		$0.47	$0.23	$0.47	$0.35

The 2010 to 2013 Long Term FTR Auction price duration curve for cleared buy bids in Figure 8-1 shows that 93.7 percent of Long Term FTRs were purchased for less than $1 per MWh, 96.6 percent for less than $2 per MWh and 97.2 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs).

Figure 8-1 Long Term FTR auction clearing price duration curve: Planning periods 2010 to 2013

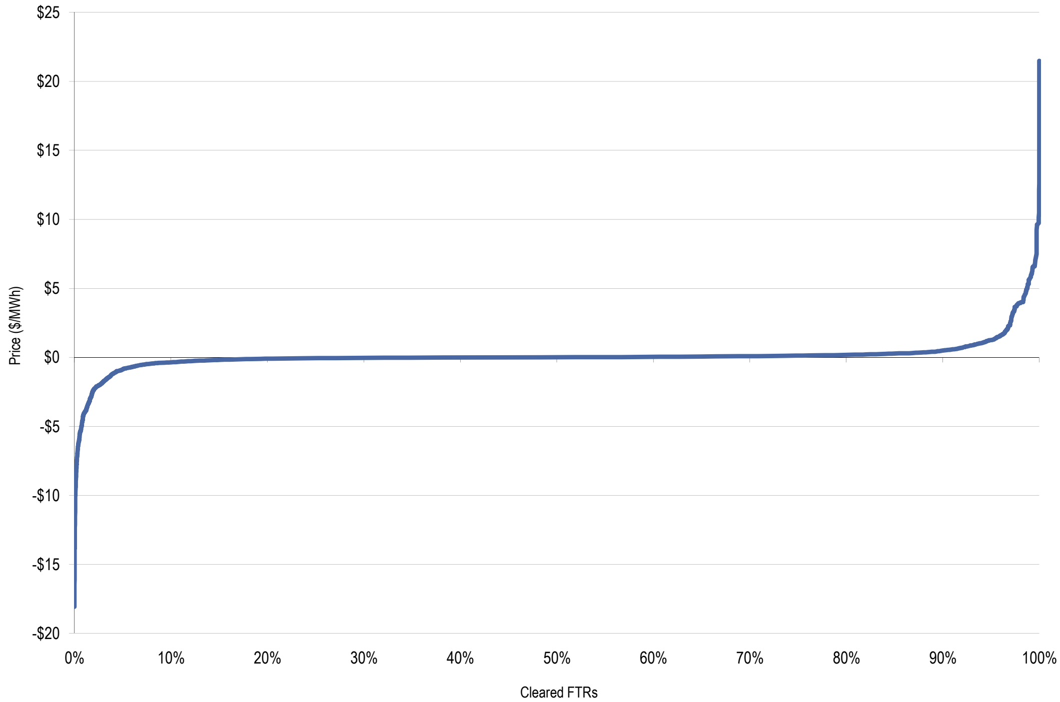


Table 8-13 shows the cleared, weighted-average prices by trade type, hedge type, FTR direction and class type for Annual FTRs during the 2009 to 2010 planning period. For the 2009 to 2010 planning period, weighted-average, buy-bid FTR obligation prices were $0.53 per MWh while weighted-average, buy-bid FTR option prices were $0.35 per MWh. Comparable weighted-average prices for the 2008 to 2009 planning period were $0.69 per MWh for buy-bid FTR obligations and $0.24 per MWh for buy-bid FTR options.

During the 2009 to 2010 planning period, weighted-average sell offer FTR obligation prices were $0.28 per MWh while weighted-average sell offer FTR option prices were $0.11 per MWh. Comparable weighted-average prices for the 2008 to 2009 planning period were $0.86 per MWh for sell offer FTR obligations and $0.84 per MWh for sell offer FTR options.

On average during the 2009 to 2010 planning period in the Annual FTR Auction, self scheduled FTRs were priced $1.05 per MWh higher than buy-bid obligation FTRs. They were priced $1.25 per MWh less than the cleared, weighted-average price of self scheduled FTRs during the 2008 to 2009 planning period.

During the 2009 to 2010 planning period, weighted-average, buy-bid FTR obligation prices were -$0.58 per MWh for counter flow FTRs and $1.13 per MWh for prevailing flow FTRs. Weighted-average sell offer FTR obligation prices were -$0.42 per MWh for counter flow FTRs and $0.63 per MWh for prevailing flow FTRs during the 2009 to 2010 planning period. On average during the 2009 to 2010 planning period in the Annual FTR Auction, self scheduled counter flow FTRs were priced

$0.26 per MWh higher than buy-bid counter flow obligation FTRs and self scheduled prevailing FTRs were priced $0.54 per MWh higher than buy-bid prevailing flow obligation FTRs.

Table 8-13 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning period 2009 to 2010

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.75)	($0.56)	($0.49)	($0.58)
		Prevailing Flow	$1.35	$1.13	$0.95	$1.13
		Total	$0.66	$0.57	$0.40	$0.53
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.53	$0.50	$0.32	$0.41
		Total	$0.18	$0.46	$0.30	$0.35
Self-scheduled bids	Obligations	Counter Flow	($0.32)	NA	NA	($0.32)
		Prevailing Flow	$1.67	NA	NA	$1.67
		Total	$1.58	NA	NA	$1.58
Buy and self-scheduled bids	Obligations	Counter Flow	($0.61)	($0.56)	($0.49)	($0.55)
		Prevailing Flow	$1.62	$1.13	$0.95	$1.44
		Total	$1.37	$0.57	$0.40	$1.03
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.53	$0.50	$0.32	$0.41
		Total	$0.18	$0.46	$0.30	$0.35
Sell offers	Obligations	Counter Flow	($1.76)	($0.24)	($0.37)	($0.42)
		Prevailing Flow	$0.49	$0.80	$0.37	$0.63
		Total	($0.28)	$0.52	$0.06	$0.28
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.04	$0.03	$0.26	$0.11
		Total	$0.04	$0.03	$0.26	$0.11

The 2009 to 2010 planning period price duration curve for cleared buy bids in Figure 8-2 shows that 83.2 percent of Annual FTRs were purchased for less than $1 per MWh, 90.6 percent for less than $2 per MWh and 93.4 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs. The 2009 to 2010 planning period FTR obligation price duration curve for cleared buy bids in Figure 8-2 shows that 81.7 percent of annual FTR obligations were purchased for less than $1 per MWh, 89.1 percent for less than $2 per MWh and 92.3 percent for less than $3 per MWh. The 2009 to 2010 planning period FTR option price duration curve for cleared buy bids in Figure 8-2 shows that 90.7 percent of annual FTR options were purchased for less than $1 per MWh, 98.0 percent for less than $2 per MWh and 99.0 percent for less than $3 per MWh.

Figure 8-2 Annual FTR auction clearing price duration curves: Planning period 2009 to 2010

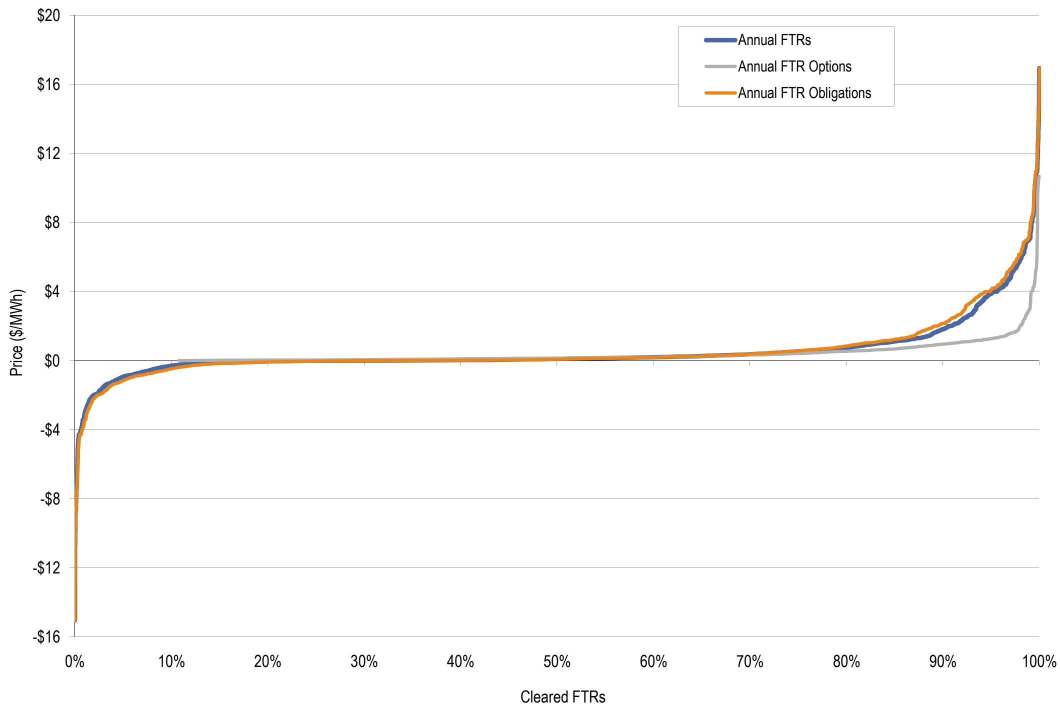


Table 8-14 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2009 through December 2009. For example, for the June 2009 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the June 2009 Monthly Balance of Planning Period FTR Auction.

The cleared, weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2009 to 2010 planning period was $0.20 per MWh, compared with $0.30 per MWh for the full 12-month 2008 to 2009 planning period.

Table 8-14 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): Calendar year 2009

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-09	$0.08	$0.18	$0.24				$0.04	$0.09
Feb-09	$0.10	$0.28	$0.21				$0.21	$0.16
Mar-09	$0.11	$0.25	$0.17				$0.55	$0.18
Apr-09	$0.12	$0.24						$0.14
May-09	$0.09							$0.09
Jun-09	$0.17	$0.25	$0.17	$1.16	$0.37	$0.48	$0.46	$0.38
Jul-09	$0.17	$0.40	$0.17		$0.25	$0.31	$0.23	$0.24
Aug-09	$0.06	$0.15	$0.19		$0.16	$0.15	$0.16	$0.12
Sep-09	$0.12	$0.28	$0.23		$0.10	$0.37	$0.34	$0.22
Oct-09	$0.08	$0.15	$0.06			$0.21	$0.18	$0.12
Nov-09	$0.09	$0.07	$0.12			$0.23	$0.26	$0.16
Dec-09	$0.05	$0.13	$0.12			$0.73	$0.16	$0.15

Revenue

Long Term FTR Auction Revenue

Table 8-15 shows Long Term FTR Auction revenue data by trade type, FTR direction, period type, and class type. The 2010 to 2013 Long Term FTR Auction netted $31.14 million in revenue, with buyers paying $39.11 million and sellers receiving $7.97 million. The 2009 to 2012 Long Term FTR Auction netted $38.93 million in revenue, with buyers paying $40.21 million and sellers receiving $1.28 million.

For the 2010 to 2013 Long Term FTR Auction, the counter flow FTRs netted -$87.68 million in revenue, with buyers receiving $87.89 million and sellers paying $0.21 million, and the prevailing flow FTRs netted $118.82 million in revenue, with buyers paying $127.00 million and sellers receiving $8.18 million.

Table 8-15 Long Term FTR Auction revenue: Planning periods 2010 to 2013

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($16,206,834)	($16,530,051)	($11,224,427)	($43,961,312)
		Year 2	($7,220,619)	($11,104,230)	($7,301,666)	($25,626,515)
		Year 3	($4,644,808)	($7,929,305)	($5,418,753)	($17,992,867)
		Year All	($308,164)	NA	NA	($308,164)
		Total	($28,380,426)	($35,563,586)	($23,944,847)	($87,888,858)
	Prevailing Flow	Year 1	$20,028,096	$25,041,954	$13,370,610	$58,440,661
		Year 2	$16,167,574	$14,826,317	$7,585,799	$38,579,691
		Year 3	$7,430,163	$14,050,302	$7,282,788	$28,763,253
		Year All	$513,923	$330,083	$367,681	$1,211,687
		Total	$44,139,757	$54,248,656	$28,606,879	$126,995,292
	Total		$15,759,332	$18,685,070	$4,662,032	$39,106,434
Sell offers	Counter Flow	Year 1	($1,282)	($99,514)	($60,657)	($161,453)
		Year 2	$0	($16,334)	($21,167)	($37,501)
		Year 3	NA	($6,535)	($3,484)	($10,019)
		Year All	NA	NA	NA	NA
		Total	($1,282)	($122,383)	($85,308)	($208,972)
	Prevailing Flow	Year 1	$55,249	$2,605,054	$1,037,322	$3,697,625
		Year 2	$0	$2,754,165	$1,287,066	$4,041,231
		Year 3	NA	$202,583	$238,825	$441,408
		Year All	NA	NA	NA	NA
		Total	$55,249	$5,561,802	$2,563,213	$8,180,264
	Total		$53,967	$5,439,419	$2,477,905	$7,971,292

Figure 8-3 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the 2010 to 2013 Long Term FTR Auction.[26] The top 10 positive revenue producing FTR sinks accounted for $62.43 million of the total revenue of $31.14 million paid in the auction.[27] They also comprised 8.2 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$23.04 million of revenue and constituted 3.5 percent of all FTRs bought in the auction.

26 As some FTRs are bid with negative prices, some winning FTR bidders are paid to take FTRs. These are counter flow FTRs. These payments reduce net auction revenue. Therefore, the sum of the highest revenue producing FTRs can exceed net auction revenue.

27 The total positive revenue producing FTR sinks was $92.12 million and the total negative revenue producing FTR sinks was -$60.98 million. The overall revenue paid in the auction was $31.14 million.

Figure 8-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2010 to 2013[28]

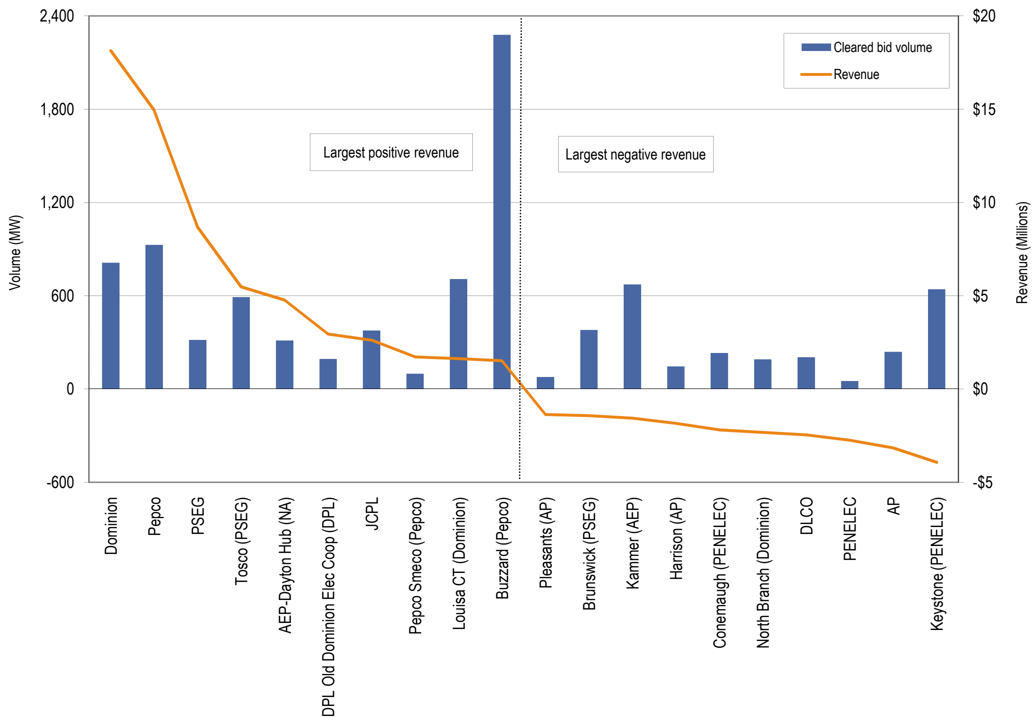
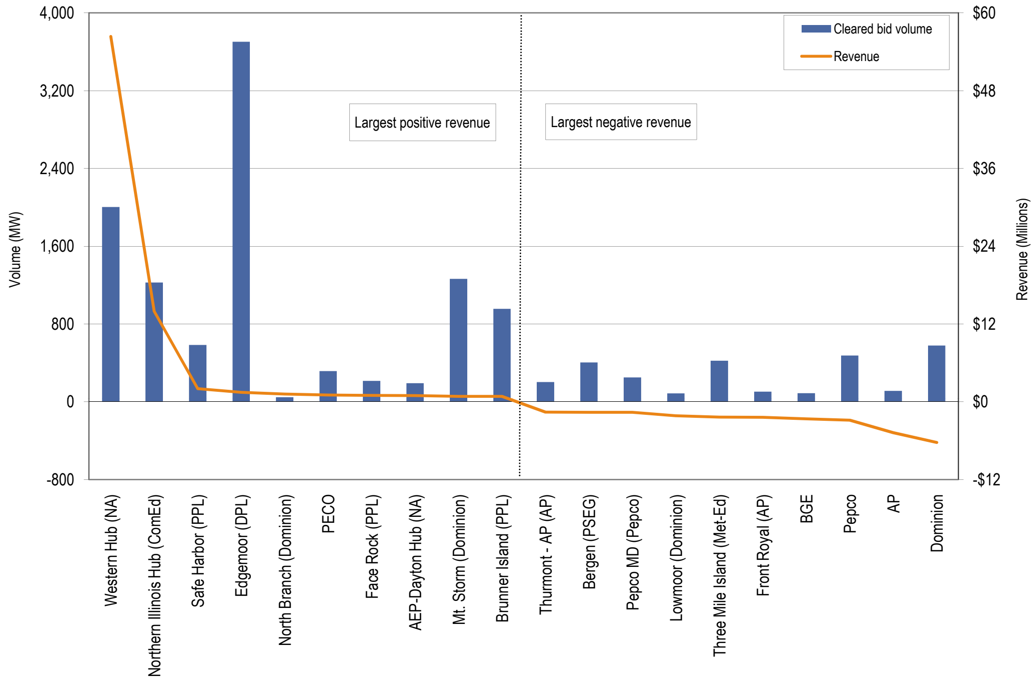


Figure 8-4 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the 2010 to 2013 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $79.63 million of the total revenue of $31.14 million paid in the auction. They also comprised 13.0 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$28.32 million of revenue and constituted 3.4 percent of all FTRs bought in the auction.

28 For Figure 8-3 through Figure 8-10, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-4 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2010 to 2013



Annual FTR Auction Revenue

Table 8-16 shows Annual FTR Auction revenue data by trade type, hedge type, FTR direction and class type. For the 2009 to 2010 planning period, the Annual FTR Auction netted $1,329.80 million in revenue, with buyers paying $1,338.88 million and sellers receiving $9.09 million. For the 2008 to 2009 planning period, the Annual FTR Auction netted $2,422.55 million in revenue, with buyers paying $2,442.57 million and sellers receiving $20.02 million.

For the 2009 to 2010 planning period, the counter flow FTRs in the Annual FTR Auction netted -$135.76 million in revenue, with buyers receiving $140.33 million and sellers paying $4.57 million, and the prevailing flow FTRs in the Annual FTR Auction netted $1,465.56 million in revenue, with buyers paying $1,479.21 million and sellers receiving $13.65 million.

Table 8-16 Annual FTR Auction revenue: Planning period 2009 to 2010

						Class Type
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($43,363,985)	($44,760,870)	($43,432,206)	($131,557,061)
		Prevailing Flow	$158,105,703	$185,216,383	$136,397,384	$479,719,470
		Total	$114,741,718	$140,455,513	$92,965,178	$348,162,410
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$2,457,455	$22,913,596	$17,326,182	$42,697,232
		Total	$2,457,455	$22,913,596	$17,326,182	$42,697,232
	Total	Counter Flow	($43,363,985)	($44,760,870)	($43,432,206)	($131,557,061)
		Prevailing Flow	$160,563,158	$208,129,979	$153,723,566	$522,416,703
		Total	$117,199,173	$163,369,109	$110,291,360	$390,859,642
Self-scheduled bids	Obligations	Counter Flow	($8,772,739)	NA	NA	($8,772,739)
		Prevailing Flow	$956,797,012	NA	NA	$956,797,012
		Total	$948,024,273	NA	NA	$948,024,273
Buy and self-scheduled bids	Obligations	Counter Flow	($52,136,724)	($44,760,870)	($43,432,206)	($140,329,799)
		Prevailing Flow	$1,114,902,715	$185,216,383	$136,397,384	$1,436,516,482
		Total	$1,062,765,992	$140,455,513	$92,965,178	$1,296,186,683
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$2,457,455	$22,913,596	$17,326,182	$42,697,232
		Total	$2,457,455	$22,913,596	$17,326,182	$42,697,232
	Total	Counter Flow	($52,136,724)	($44,760,870)	($43,432,206)	($140,329,799)
		Prevailing Flow	$1,117,360,170	$208,129,979	$153,723,566	$1,479,213,715
		Total	$1,065,223,446	$163,369,109	$110,291,360	$1,338,883,915
Sell offers	Obligations	Counter Flow	($1,385,244)	($1,089,452)	($2,094,504)	($4,569,201)
		Prevailing Flow	$736,568	$9,964,413	$2,864,123	$13,565,105
		Total	($648,676)	$8,874,961	$769,619	$8,995,904
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$15,598	$5,268	$68,488	$89,353
		Total	$15,598	$5,268	$68,488	$89,353
	Total	Counter Flow	($1,385,244)	($1,089,452)	($2,094,504)	($4,569,201)
		Prevailing Flow	$752,166	$9,969,681	$2,932,611	$13,654,458
		Total	($633,078)	$8,880,229	$838,107	$9,085,257

Figure 8-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the Annual FTR Auction for the 2009 to 2010 planning period. The top 10 positive revenue producing FTR sinks accounted for $1,096.93 million (82.5 percent) of the total revenue of $1,329.80 million paid in the auction. They also comprised 37.7 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing

FTR sinks accounted for -$24.50 million of revenue and constituted 2.4 percent of all FTRs bought in the auction.

Figure 8-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2009 to 2010

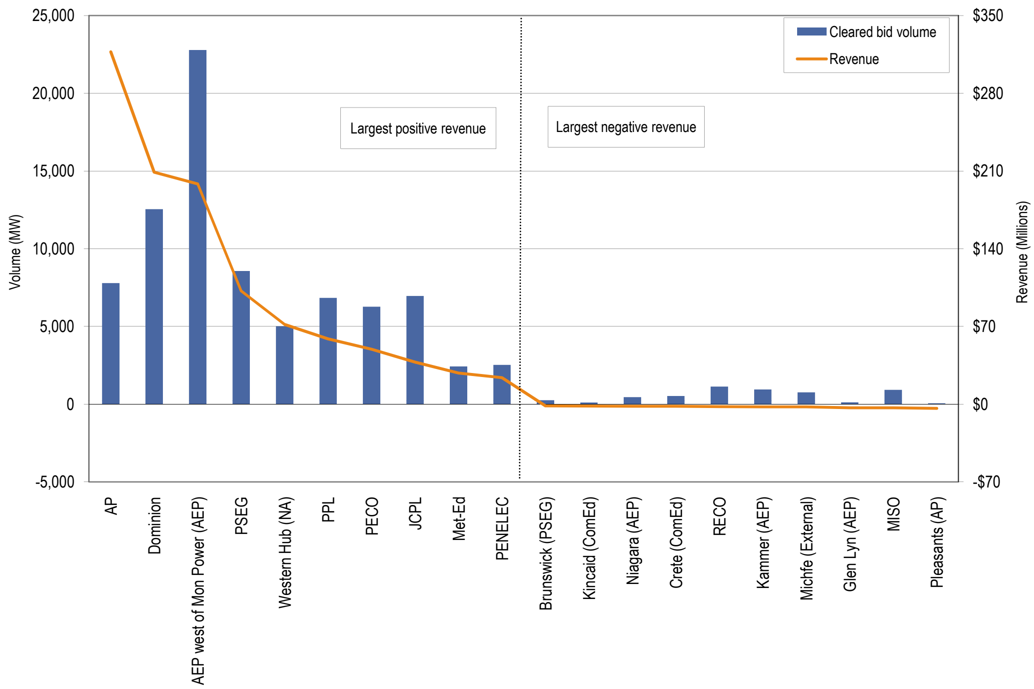
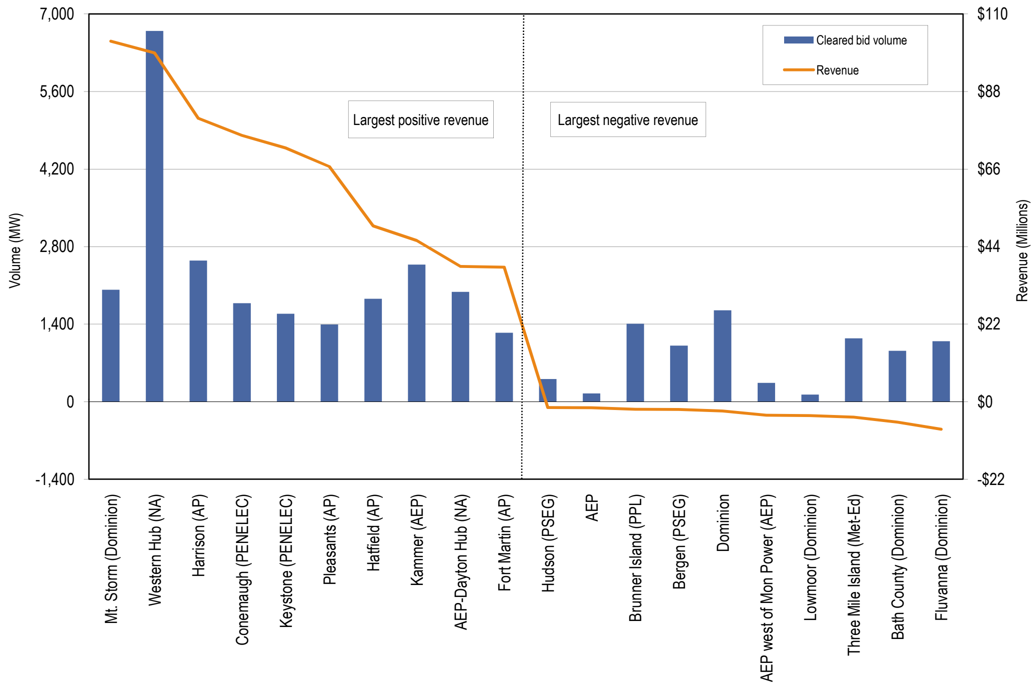


Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Annual FTR Auction for the 2009 to 2010 planning period. The top 10 positive revenue producing FTR sources accounted for $667.87 million (50.2 percent) of the total revenue of $1,329.80 million paid in the auction. They also comprised 10.9 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$36.35 million of revenue and constituted 3.8 percent of all FTRs bought in the auction.

Figure 8-6 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2009 to 2010



Monthly Balance of Planning Period FTR Auction Revenue

Table 8-17 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, hedge type and class type. For the 2009 to 2010 planning period through December 31, 2009, the Monthly Balance of Planning Period FTR Auctions netted $13.07 million in revenue, with buyers paying $60.22 million and sellers receiving $47.15 million. For the 2008 to 2009 planning period, the Monthly Balance of Planning Period FTR Auctions netted $67.05 million in revenue, with buyers paying $128.97 million and sellers receiving $61.92 million.

Table 8-17 Monthly Balance of Planning Period FTR Auction revenue: Calendar year 2009

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-09	Obligations	Buy bids	$1,207,292	$934,011	$244,584	$2,385,888
		Sell offers	$248,591	$573,963	$77,911	$900,466
	Options	Buy bids	$26,505	$140,359	$145,245	$312,108
		Sell offers	$0	$203,453	$129,447	$332,900
Feb-09	Obligations	Buy bids	($83,145)	$2,193,269	$1,332,926	$3,443,050
		Sell offers	$413,446	$1,442,454	$530,041	$2,385,941
	Options	Buy bids	$31,233	$278,934	$178,062	$488,229
		Sell offers	$0	$193,821	$118,916	$312,737
Mar-09	Obligations	Buy bids	$395,276	$2,107,188	$1,467,981	$3,970,446
		Sell offers	$308,687	$1,724,949	$1,167,153	$3,200,789
	Options	Buy bids	$34,097	$435,416	$54,453	$523,967
		Sell offers	$0	$181,733	$52,487	$234,221
Apr-09	Obligations	Buy bids	($223,411)	$1,471,041	$1,062,859	$2,310,489
		Sell offers	$19,324	$954,279	$602,223	$1,575,826
	Options	Buy bids	$1,511	$291,731	$15,883	$309,126
		Sell offers	$0	$260,520	$67,733	$328,253
May-09	Obligations	Buy bids	($234,075)	$902,305	$371,453	$1,039,683
		Sell offers	($12,927)	$429,537	$118,031	$534,641
	Options	Buy bids	$0	$10,099	$8,754	$18,854
		Sell offers	$1,336	$115,521	$48,174	$165,031
Jun-09	Obligations	Buy bids	($455,827)	$9,859,792	$7,471,308	$16,875,272
		Sell offers	$940,697	$4,742,041	$3,783,072	$9,465,811
	Options	Buy bids	$0	$454,961	$67,016	$521,977
		Sell offers	$21,245	$3,150,642	$1,819,405	$4,991,291
Jul-09	Obligations	Buy bids	$415,277	$4,786,066	$4,229,832	$9,431,174
		Sell offers	($59,890)	$2,992,345	$2,645,320	$5,577,775
	Options	Buy bids	$25,700	$221,441	$78,308	$325,449
		Sell offers	$1,231	$959,249	$766,196	$1,726,677
Aug-09	Obligations	Buy bids	$300,985	$2,594,442	$1,835,069	$4,730,497
		Sell offers	($35,209)	$1,385,079	$1,265,654	$2,615,525
	Options	Buy bids	NA	$151,123	$3,931	$155,054
		Sell offers	$130	$512,880	$284,359	$797,368
Sep-09	Obligations	Buy bids	$1,017,942	$4,713,934	$3,266,091	$8,997,967
		Sell offers	$453,760	$3,108,304	$2,190,037	$5,752,101
	Options	Buy bids	$42,397	$103,279	$85,804	$231,480
		Sell offers	$2,554	$1,000,222	$537,203	$1,539,979
Oct-09	Obligations	Buy bids	$217,461	$2,417,026	$2,329,518	$4,964,005
		Sell offers	($3,094)	$1,182,029	$1,200,681	$2,379,616
	Options	Buy bids	NA	$61,586	$68,144	$129,730
		Sell offers	$22,884	$764,026	$649,044	$1,435,954
Nov-09	Obligations	Buy bids	($2,883,260)	$5,357,702	$3,927,246	$6,401,688
		Sell offers	$288,449	$1,459,674	$1,306,985	$3,055,109
	Options	Buy bids	$0	$168,017	$55,779	$223,796
		Sell offers	$35,176	$1,289,570	$852,156	$2,176,902
Dec-09	Obligations	Buy bids	$2,273,482	$3,395,670	$1,346,904	$7,016,056
		Sell offers	$1,035,061	$2,107,920	$1,227,779	$4,370,760
	Options	Buy bids	$29,551	$98,932	$88,190	$216,673
		Sell offers	$6,525	$667,140	$595,297	$1,268,963
2008/2009*	Obligations	Buy bids	$18,536,366	$62,983,127	$39,113,790	$120,633,283
		Sell offers	$10,238,514	$20,746,786	$12,003,977	$42,989,277
	Options	Buy bids	$164,213	$5,175,296	$2,995,811	$8,335,320
		Sell offers	$26,515	$13,614,983	$5,286,634	$18,928,133
2009/2010**	Obligations	Buy bids	$886,061	$33,124,632	$24,405,967	$58,416,660
		Sell offers	$2,619,774	$16,977,392	$13,619,529	$33,216,695
	Options	Buy bids	$97,648	$1,259,338	$447,173	$1,804,159
		Sell offers	$89,745	$8,343,729	$5,503,660	$13,937,134

* Shows Twelve Months for 2008/2009; ** Shows seven months ended 31-Dec-2009 for 2009/2010

Figure 8-7 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2009 to 2010 planning period. The top 10 positive revenue producing FTR sinks accounted for $46.80 million of revenue and 13.1 percent of all FTRs bought in the Monthly Balance of Planning Period FTR Auctions. In the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2009 to 2010 planning period, there were 551 MW cleared bids for FTRs sunk at the new Neptune 230 kV line which generated $0.1 million of revenue. In the Monthly Balance of Planning Period FTR Auctions during the 2008 to 2009 planning period, there were 1,013 MW cleared bids for FTRs sunk at the new Neptune 230 kV line which generated $2.4 million of revenue. There were no FTRs sunk at the new Linden VFT line during the first seven months of the 2009 to 2010 planning period. The top 10 negative revenue producing FTR sinks accounted for -$12.91 million of revenue and constituted 2.0 percent of all FTRs bought in the auctions. The net market volume sunk into the Western Hub was negative since the total cleared volume of the monthly FTR buy bids sunk into the West Interface Hub was less than the total cleared volume of the monthly FTR sell offers sunk into the West Interface Hub.

Figure 8-7 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through December 31, 2009

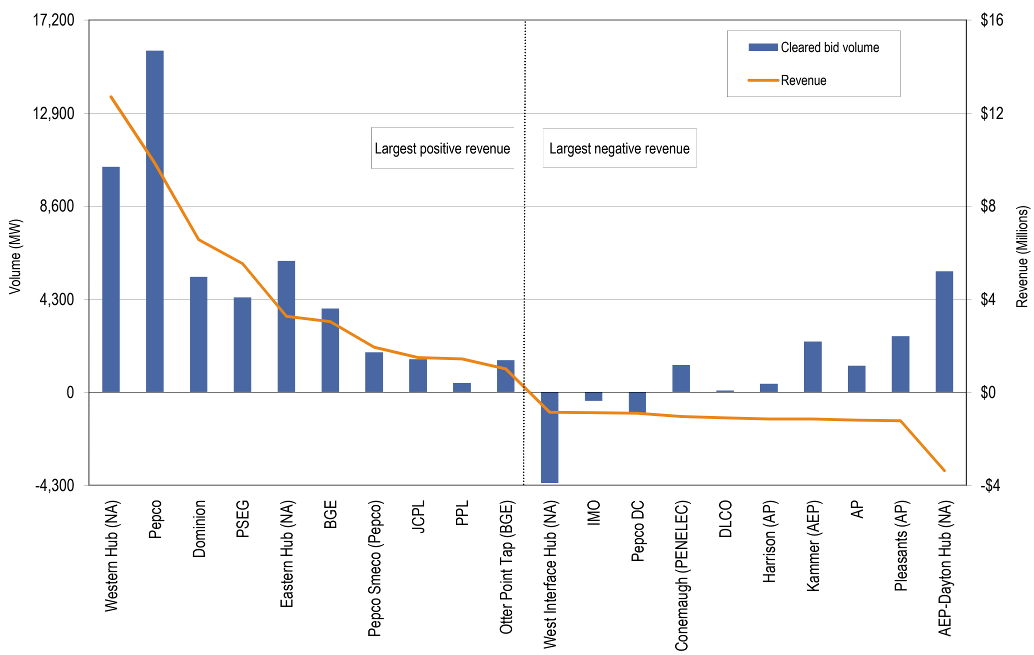
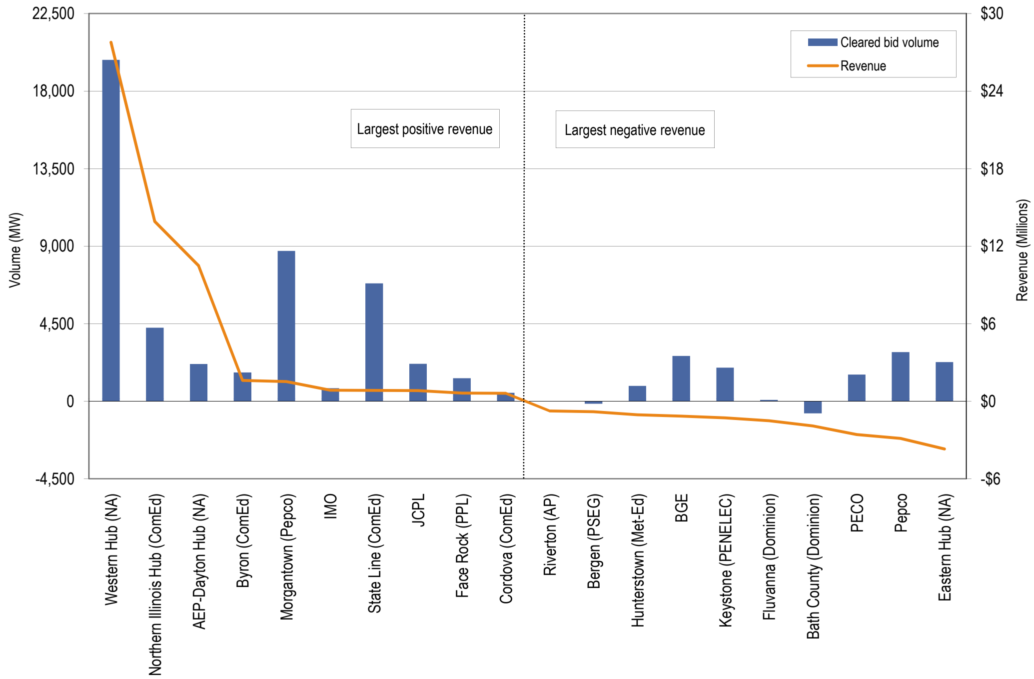


Figure 8-8 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2009 to 2010 planning period. The top 10 positive revenue producing FTR sources accounted for $59.05 million and 12.3 percent of all FTRs bought in the auctions. The top 10 negative revenue producing FTR sources accounted for -$17.64 million of revenue and constituted 2.9 percent of all FTRs bought in the auctions.

Figure 8-8 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2009 to 2010 through December 31, 2009



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The MW of load exceeds the MW of generation in constrained areas because a part of the load is served by imports using transmission capability into the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in a constrained area receives the congestion price and all load in the constrained area pays the congestion price. As a result, load congestion payments are usually greater than the congestion-related increase in payments to generation.[29] In general, FTR revenue adequacy exists when the sum of congestion credits is as great as the sum of congestion across the positively valued FTRs.

Revenue adequacy must be distinguished from the adequacy of FTRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which FTRs were available and purchased. The adequacy of FTRs as a hedge against congestion compares FTR revenues to total congestion on the system as a measure of the extent to which FTRs hedged market participants against actual, total congestion across all paths, regardless of the availability or purchase of FTRs.

29 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *2009 State of the Market Report for PJM*, Volume II, Appendix G, "Financial Transmission and Auction Revenue Rights."

FTRs are paid out for each month from congestion revenues, FTR auction revenues and excess revenues carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2008 to 2009 planning period, FTRs were fully funded and thus no uplift charge was collected. Table 8-18 shows the composition of FTR target allocations and FTR revenues for the 2008 to 2009 and the 2009 to 2010 planning periods, with the latter shown through December 31, 2009. FTR targets are composed of FTR target allocations and associated adjustments. Other adjustments may be made for items such as modeling changes or errors.

FTR revenues are primarily comprised of hourly congestion revenue and net negative congestion. FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 8-18 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[30] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $0.5 million in congestion charges to Con Edison in the 2009 to 2010 planning period through December 31, 2009.[31,32]

30 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 11, 2008) (Accessed January 19, 2010), Section 6.1 <http://www.pjm.com/~/Media/documents/agreements/joa-complete.ashx> (1,528 KB).

31 111 FERC ¶ 61,228 (2005).

32 See the *2009 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "Con Edison and PSE&G Wheeling Contracts 2009 Update" and Appendix D, "Interchange Transactions" at Table D-1, "Con Edison and PSE&G wheel settlements data: Calendar year 2009."

Table 8-18 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010

Accounting Element	2008/2009	2009/2010*
ARR information		
ARR target allocations	$2,361.3	$747.6
FTR auction revenue	$2,489.6	$799.1
ARR excess	$128.3	$51.5
FTR targets		
FTR target allocations	$1,747.9	$398.1
Adjustments:		
Adjustments to FTR target allocations	($4.1)	($0.5)
Total FTR targets	$1,743.8	$397.6
FTR revenues		
ARR excess	$128.3	$51.5
Competing uses	$0.7	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($59.0)	($20.1)
Hourly congestion revenue	$1,735.7	$380.9
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($52.3)	($23.4)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($3.1)	($0.5)
Adjustments:		
Excess revenues carried forward into future months	$36.8	$23.5
Excess revenues distributed back to previous months	$16.1	$8.5
Other adjustments to FTR revenues	($2.0)	($0.2)
Total FTR revenues	$1,801.2	$420.2
Excess revenues distributed to other months	($30.0)	($31.9)
Excess revenues distributed to CEPSW for end-of-year distribution	$0.5	$0.0
Excess revenues distributed to FTR holders	$4.0	$0.0
Total FTR congestion credits	$1,743.8	$388.3
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,751.4	$388.8
Remaining deficiency	$0.0	$9.3

* Shows seven months ended 31-Dec-09

FTR target allocations are based on hourly prices in the Day-Ahead Energy Market for the respective FTR paths and equal the revenue required to hedge FTR holders fully against congestion on the specific paths for which the FTRs are held. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 8-19 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies. FTRs were paid at 100 percent of the target allocation level for the 2008 to 2009 planning period and were paid at 97.7 percent of the target allocation level for the 2009 to 2010 planning period through December 31, 2009.

The total row in Table 8-19 is not the simple sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues carried back from later months. For example, August 2009 FTR revenues are shown as $90.0 million, which includes revenues from congestion charges for the month, excess revenues carried forward from prior months ($12.8 million) and excess revenues carried back from later months ($2.2 million). For the 2008 to 2009 planning period, the total FTR revenues were $1,748.3 million which is the sum of total FTR credits ($1,743.8 million) and total excess credits ($4.5 million). For the first seven months of the 2009 to 2010 planning period, the total FTR revenues were $388.3 million, which equal the total FTR credits ($388.3 million) because there were credit deficiencies of $9.3 million.

Table 8-19 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010

Period	FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Jun-08	$436.9	$432.3	$432.3	100%	$0	$4.7
Jul-08	$371.4	$364.2	$364.2	100%	$0	$7.2
Aug-08	$140.5	$125.0	$125.0	100%	$0	$15.4
Sep-08	$154.6	$154.6	$154.6	100%	$0	$0.0
Oct-08	$109.4	$109.4	$109.4	100%	$0	$0.0
Nov-08	$97.2	$97.2	$97.2	100%	$0	$0.0
Dec-08	$85.3	$77.6	$77.6	100%	$0	$7.7
Jan-09	$159.5	$151.1	$151.1	100%	$0	$8.4
Feb-09	$92.0	$84.3	$84.3	100%	$0	$7.7
Mar-09	$86.7	$86.7	$86.7	100%	$0	$0.0
Apr-09	$32.8	$31.1	$31.1	100%	$0	$1.7
May-09	$34.8	$30.3	$30.3	100%	$0	$4.5
Summary for Planning Period 2008 to 2009						
Total	$1,748.3	$1,743.8	$1,743.8	100%	$0	$4.5
Jun-09	$54.6	$43.9	$43.9	100%	$0	$10.7
Jul-09	$53.2	$40.4	$40.4	100%	$0	$12.8
Aug-09	$90.0	$92.4	$90.0	97.4%	$2.4	$0.0
Sep-09	$29.3	$31.4	$29.3	93.5%	$2.0	$0.0
Oct-09	$52.9	$57.8	$52.9	91.5%	$4.9	$0.0
Nov-09	$38.2	$37.9	$37.9	100%	$0.0	$0.3
Dec-09	$101.9	$93.8	$93.8	100%	$0.0	$8.2
Summary for Planning Period 2009 to 2010 through Dec 31, 2009						
Total	$388.3	$397.6	$388.3	97.7%	$9.3	$0.0

FTR target allocations were examined separately. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source for the 2009 to 2010 planning period through December 31, 2009. Figure 8-9 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 64.8 percent of total positive target allocations during the first seven months of the 2009 to 2010 planning period. FTRs with the AP Control Zone as the sink included 13.0 percent of all positive target allocations. The sinks with the highest positive target allocations are all control zones or large aggregates. The top 10 sinks that created liability accounted for 43.9 percent of total negative target allocations. FTRs with the Northern Illinois Hub as the sink encompassed 6.4 percent of all negative target allocations.

Figure 8-9 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2009 to 2010 through December 31, 2009

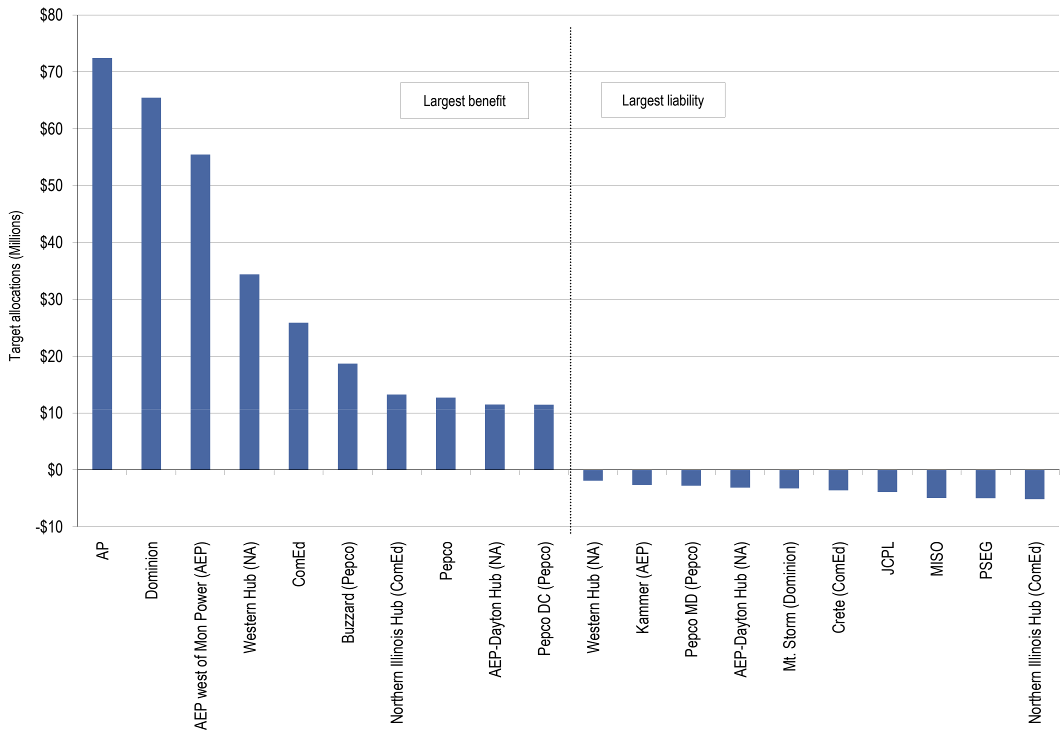
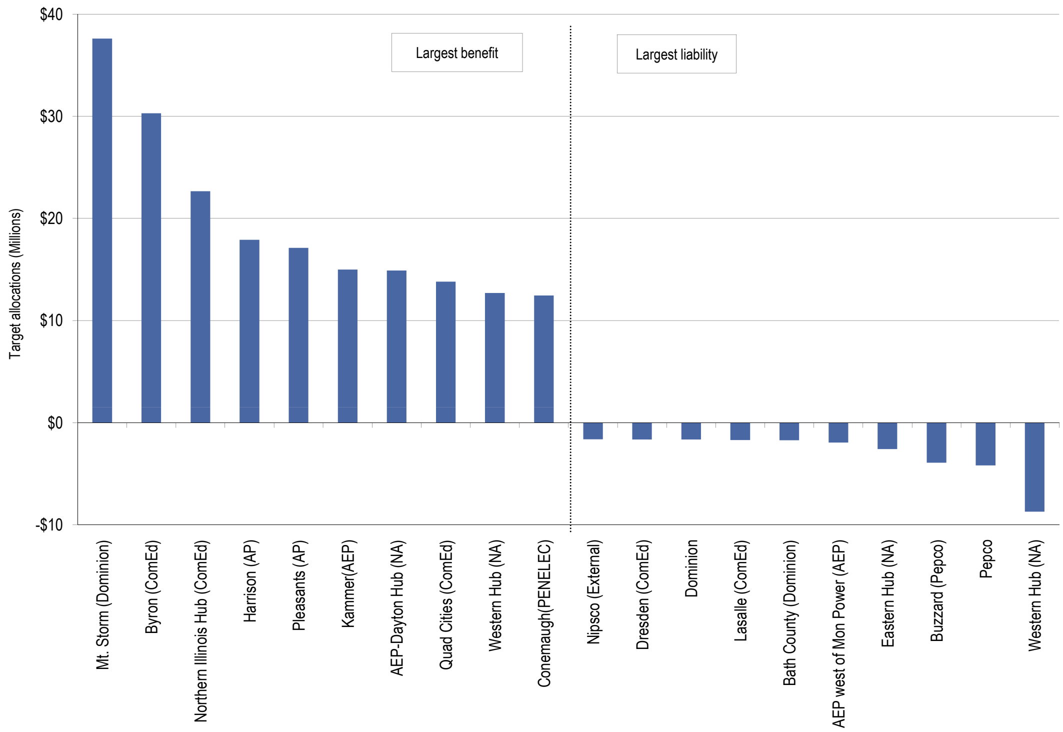


Figure 8-10 shows the FTR sources with the largest positive and negative target allocations during the first seven months of the 2009 to 2010 planning period. The top 10 sources with a positive target allocation accounted for 39.8 percent of total positive target allocations. FTRs with the Mount Storm aggregate as their source included 7.7 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 32.6 percent of total negative target allocations. FTRs with the Western Hub as the source encompassed 9.6 percent of all negative target allocations.

Figure 8-10 Ten largest positive and negative FTR target allocations summed by source: Planning period 2009 to 2010 through December 31, 2009



Auction Revenue Rights

FTRs and ARRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational congestion price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or to pay charges based on prices determined in the Annual FTR Auction.[33] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the sink-minus-source price difference, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. All ARR holders receive ARR credits equal to

33 These nodal prices are a function of the market participants' annual FTR bids and binding transmission constraints. An optimization algorithm selects the set of feasible FTR bids that produces the most net revenue.

their target allocations if total net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than, or equal to, the sum of all ARR target allocations. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are less than that, available revenue is proportionally allocated among all ARR holders.

ARRs are available only as obligation hedge type and 24-hour class type products. An ARR obligation provides a credit, positive or negative, equal to the product of the ARR MW and the price difference between ARR sink and source that occurs in the Annual FTR Auction. The 24-hour products are effective 24 hours a day, seven days a week.

When a new control zone is integrated into PJM, the participants in that control zone must choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are ineligible for directly allocated FTRs.

Market Structure

ARRs have been available to network service and firm, point-to-point transmission service customers since June 1, 2003, when the annual ARR allocation was first implemented for the 2003 to 2004 planning period. The initial allocation covered the Mid-Atlantic Region and the AP Control Zone. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the AEP, DAY, DLCO and Dominion control zones. For the 2007 to 2008 and subsequent planning periods, all eligible market participants were allocated ARRs.

Supply

ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of ARRs that are feasible.

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[34] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10 planning period time frame. Long Term ARR holders can opt out of any planning period during the 10 planning period timeline and self schedule their Long Term ARRs as FTRs.

Each March, PJM allocates ARRs to eligible customers in a three-stage process, whereby the first and second stages are each one round and the third stage is a three-round allocation procedure:

34 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain Long Term ARRs, up to their share of the zonal base load, after taking into account generation resources that historically have served load in each control zone and up to 50 percent of their historical nonzone network load. Nonzone network load is load that is located outside of the PJM footprint. Firm, point-to-point transmission service customers can obtain Long Term ARRs, based on up to 50 percent of the MW of long-term, firm, point-to-point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARR holders can also opt out of any planning period during the 10-planning-period timeline and self schedule their Long Term ARRs as FTRs.

- **Stage 1B.** ARRs unallocated in Stage 1A are available in the Stage 1B allocation. Network transmission service customers can obtain ARRs, up to their share of the zonal peak load, based on generation resources that historically have served load in each control zone and up to 100 percent of their transmission responsibility for nonzone network load. Firm, point-to-point transmission service customers can obtain ARRs based on the MW of long-term, firm, point-to-point service provided between the receipt and delivery points for the historical reference year. These long-term point-to-point service agreements must also remain in effect for the planning period covered by the allocation.

- **Stage 2.** The third stage of the annual ARR allocation is a three-step procedure, with one-third of the remaining system capability allocated in each step of the process. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in Stage 1A or Stage 1B. Firm, point-to-point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[35] Participants may seek additional ARRs in the Stage 2 allocation.

ARRs can also be traded between LSEs, but these trades must be made before the first round of the Annual FTR Auction. LSEs trading ARRs must trade all of their ARRs associated with a control zone and their zonal network service peak load is also reassigned to the new LSE. Traded ARRs are effective for the full 12-month planning period.

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on reasonable assumptions about the configuration and availability of transmission capability during the planning period.[36] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is

35 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 21.
36 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.

not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 8-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) • (Individual requested MW / Total requested MW) • (1 / MW effect on line).[37]

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested MW of ARR that would have a power flow on the binding constraint. The PJM methodology prorates those ARR requests with the greatest impact on the binding constraint to avoid prorating more requests but having smaller or minimal impact on the binding constraint. PJM's method results in the prorating of ARRs that cause the greatest flows on the binding constraint instead of those that produce less flow on it. Were all ARR requests prorated equally, irrespective of their proportional impact on the binding constraints, the result would be a significant reduction in market participants' ARRs even when they have little impact on the binding constraints and the reduction of ARRs, and their associated benefits, with primary impacts on unrelated constraints.

Residual ARRs

On June 19, 2007, PJM submitted to the FERC revisions to the OATT to include a new type of ARR known as a residual ARR.[38] On August 13, 2007, the FERC issued an order accepting the revisions to the PJM OATT with an effective date of August 20, 2007.[39] Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs would be available if additional transmission system capability were added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs would be effective on the first day of the month in which the additional transmission system capability is included in FTR auctions and would exist until the end of the planning period. For the following planning period, any residual ARRs would be available as ARRs in the annual ARR allocation process as they would be included in the power flow model. The amount of a residual ARR would be the difference between the ARR holder's Stage 1A or Stage 1B request and their actual prorated Stage 1A or Stage 1B ARR MW. Stage 1 ARR holders have a priority right to ARRs and those holders who had ARRs prorated because of the simultaneous feasibility requirement previously had no recourse from the impact of proration. Residual ARRs are a separate product from incremental ARRs. No residual ARRs have been allocated to date.

37 See the *2009 State of the Market Report for PJM*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

38 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff pursuant to Section 205 of the Federal Power Act, Docket No. ER07-1053-000 (June 19, 2007).

39 *PJM Interconnection, L.L.C.*, Letter Order accepting PJM Interconnection, L.L.C.'s June 19, 2007, filing of Second Revised Sheet No. 6A et al to the Third Revised Rate Schedule, FERC No. 24 et al, Docket No. ER07-1053-000 (August 13, 2007).

Incremental ARRs

Market participants constructing generation interconnection or transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[40] Incremental ARRs are available in a three-round allocation process with a single point-to-point combination requested and one-third of the incremental ARR MW allocated in each round. Incremental ARRs can be accepted or refused after rounds one and two. If accepted, that ARR is removed from availability in subsequent rounds; if it is refused, that ARR is available in the next rounds. Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, in place of continuing this 30-year ARR, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall the system simultaneous feasibility can be Table 8-20 lists the incremental ARR allocation volume for the 2008 to 2009 and the 2009 to 2010 planning periods. For the 2009 to 2010 planning period, there were bids for 531 MW and 100 percent of the bids were cleared. For the 2008 to 2009 planning period, there were bids for 891 MW and 100 percent of the bids were cleared.

Table 8-20 Incremental ARR allocation volume: Planning periods 2008 to 2009 and 2009 to 2010

Planning Period	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	891	891	100%	0	0%
2009/2010	14	531	531	100%	0	0%

Table 8-21 lists the top 10 principal binding constraints, along with their corresponding control zones in order of severity that limited supply in the annual ARR allocation for the 2009 to 2010 planning period. The order of severity is determined by the violation degree of the binding constraint as computed in the simultaneous feasibility test.[41] The violation degree is a measure of the MW that a constraint is over the limit for a type of facility; a higher number indicates a more severe constraint.

Table 8-21 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2009 to 2010

Constraint	Type	Control Zone
AP South	Interface	AP
Electric Junction - Frontenac	Line	ComEd
Linden - North Ave	Line	PSEG
East Frankfort - Braidwood	Line	ComEd
Des Plaines	Transformer	ComEd
Doubs	Transformer	AP
North Seaford - Pine Street	Line	DPL
Garman - Westover	Line	PENELEC
Logans Ferry - Universal	Line	DLCO
Joliet - Joliet Central	Line	ComEd

40 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 30.
41 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 54-55.

Demand

PJM's OATT specifies the types of transmission services that are available to eligible customers. Eligible customers submit requests to PJM for network and firm, point-to-point transmission service through the PJM Open Access Same-Time Information System (OASIS). ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can also be requested through the PJM OASIS.[42] PJM evaluates each transmission service request for its impact on the system and approves or denies the request accordingly. All approved transmission services can be accommodated by the PJM transmission system. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm, point-to-point transmission service, ARR supply should equal ARR demand if ARR nominations are consistent with the historic use of the transmission system. However, the demand for some ARRs could be left unmet if the same resources are nominated as ARR source points by multiple parties for delivery across shared paths and the result exceeds the stated capability of the transmission system to deliver from those sources to load. The combination might not be simultaneously feasible. When the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches among LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[43] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the hedge.

The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. This would include both FTRs that are directly self scheduled and FTRs on paths identical to the ARR, which are financially equivalent to self scheduled FTRs. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. The underlying FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches.

42 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 16-17.
43 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 28.

Table 8-22 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2008 and December 2009. About 10,531 MW of ARRs associated with $195,300 per MW-day of revenue were automatically reassigned in the first seven months of the 2009 to 2010 planning period. About 15,326 MW of ARRs with $533,900 per MW-day of revenue were reassigned for the entire 12-month 2008 to 2009 planning period.

Table 8-22 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2008, through December 31, 2009

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2008/2009 (12 months)	2009/2010 (7 months)*	2008/2009 (12 months)	2009/2010 (7 months)*
AECO	501	327	$16.1	$6.0
AEP	11	244	$0.2	$5.8
AP	707	413	$164.7	$48.0
BGE	3,361	2,112	$124.3	$43.7
ComEd	3,074	1,760	$10.0	$5.4
DAY	1	2	$0.0	$0.0
DLCO	471	217	$2.1	$0.6
Dominion	5	0	$0.4	$0.0
DPL	1,404	747	$24.8	$8.5
JCPL	1,094	864	$45.0	$13.1
Met-Ed	0	10	$0.0	$0.2
PECO	47	20	$1.4	$0.3
PENELEC	0	1	$0.0	$0.0
Pepco	3,040	1,949	$79.9	$19.9
PPL	35	282	$2.2	$5.8
PSEG	1,537	1,535	$62.7	$38.0
RECO	40	50	$0.0	$0.0
Total	15,326	10,531	$533.9	$195.3

* Through 31-Dec-09

Market Performance

Volume

Table 8-23 lists the annual ARR allocation volume by stage and round for the 2008 to 2009 and the 2009 to 2010 planning periods. For the 2009 to 2010 planning period, there were 64,987 MW (46.4 percent of total demand) bid in Stage 1A, 26,517 MW (18.9 percent of total demand) bid in Stage 1B and 48,533 MW (34.7 percent of total demand) bid in Stage 2. Of 140,037 MW in total ARR requests, 64,913 MW were allocated in Stage 1A and 26,514 MW were allocated in Stage 1B while 17,986 MW were allocated in Stage 2 for a total of 109,413 MW (78.1 percent) allocated. Eligible market participants subsequently converted 68,589 MW of these allocated ARRs into Annual FTRs (62.7 percent of total allocated ARRs), leaving 40,824 MW of ARRs outstanding. For the 2008 to 2009 planning period, there had been 64,546 MW (45.9 percent of total demand) bid in Stage 1A, 27,291 MW (19.4 percent of total demand) bid in Stage 1B and 48,831 MW (34.7 percent of total demand) bid in Stage 2. Of 140,668 MW in total ARR requests, 64,520 MW were allocated in Stage 1A and 26,685 MW were allocated in Stage 1B while 20,806 MW were allocated in Stage 2 for a total of 112,011 MW (79.6 percent) allocated. There were 72,851 MW or 65.0 percent of the allocated ARRs converted into FTRs. Immediately after the Stage 1B ARR allocation for the 2009 to 2010 planning period, ARR holders relinquished 2.9 MW of the allocated Stage 1B ARRs. In comparison, for the 2008 to 2009 planning period, ARR holders relinquished 26.8 MW of the allocated Stage 1A ARRs and 0.3 MW of the allocated Stage 1B ARRs. The uncleared volume in Table 8-23 includes ARRs that were relinquished.

Table 8-23 Annual ARR allocation volume: Planning periods 2008 to 2009 and 2009 to 2010

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	1A	0	7,845	64,546	64,520	100.0%	26	0.0%
	1B	1	3,147	27,291	26,685	97.8%	606	2.2%
	2	2	1,691	16,737	6,753	40.3%	9,984	59.7%
		3	1,312	15,464	6,304	40.8%	9,160	59.2%
		4	1,118	16,630	7,749	46.6%	8,881	53.4%
		Total	4,121	48,831	20,806	42.6%	28,025	57.4%
	Total		15,113	140,668	112,011	79.6%	28,657	20.4%
2009/2010	1A	0	7,527	64,987	64,913	99.9%	74	0.1%
	1B	1	3,582	26,517	26,514	100.0%	3	0.0%
	2	2	1,580	16,521	5,680	34.4%	10,841	65.6%
		3	1,157	16,413	6,013	36.6%	10,400	63.4%
		4	994	15,599	6,293	40.3%	9,306	59.7%
		Total	3,731	48,533	17,986	37.1%	30,547	62.9%
	Total		14,840	140,037	109,413	78.1%	30,624	21.9%

Revenue

As ARRs are allocated to qualifying customers rather than sold, there is no ARR revenue comparable to the revenue that results from the FTR auctions.

Revenue Adequacy

The degree to which ARR credits provide a hedge against congestion on specific ARR paths is determined by the prices that result from the Annual FTR Auction. The resultant ARR credit could be greater than, less than, or equal to the actual congestion on the selected path. This is the same concept as FTR revenue adequacy.

Customers that are allocated ARRs can choose to retain the underlying FTRs linked to their ARRs through a process termed self scheduling. Just like any other FTR, the underlying FTRs have a target hedge value based on actual day-ahead congestion on the selected path.

As with FTRs, revenue adequacy for ARRs must be distinguished from the adequacy of ARRs as a hedge against congestion. Revenue adequacy is a narrower concept that compares the revenues available to cover congestion across specific paths for which ARRs were available and allocated. The adequacy of ARRs as a hedge against congestion compares ARR revenues to total congestion sinking in the participant's load zone as a measure of the extent to which ARRs hedged market participants against actual, total congestion into their zone, regardless of the availability or allocation of ARRs.

ARR holders will receive $1,273.5 million in credits from the Annual FTR Auction during the 2009 to 2010 planning period, with an average hourly ARR credit of $1.33 per MWh. During the comparable 2008 to 2009 planning period, ARR holders received $2,361.3 million in ARR credits, with an average hourly ARR credit of $2.41 per MWh.

Table 8-24 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2008 to 2009 and the 2009 to 2010 (through December 31, 2009) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for both planning periods. The 2009 to 2010 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $69.4 million in auction net revenue through December 31, 2009, above the amount needed to pay 100 percent of ARR target allocations. The whole 2008 to 2009 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $128.3 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-24 ARR revenue adequacy (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010

	2008/2009	2009/2010
Total FTR auction net revenue	$2,489.6	$1,342.9
Annual FTR Auction net revenue	$2,422.6	$1,329.8
Monthly Balance of Planning Period FTR Auction net revenue*	$67.1	$13.1
ARR target allocations	$2,361.3	$1,273.5
ARR credits	$2,361.3	$1,273.5
Surplus auction revenue	$128.3	$69.4
ARR payout ratio	100%	100%
FTR payout ratio*	100%	97.7%

* Shows twelve months for 2008/2009 and seven months ended 31-Dec-09 for 2009/2010

ARR Proration

During the annual ARR allocation process, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. If all the ARR requests made during the annual ARR allocation process are not feasible, then ARRs are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.[44,45]

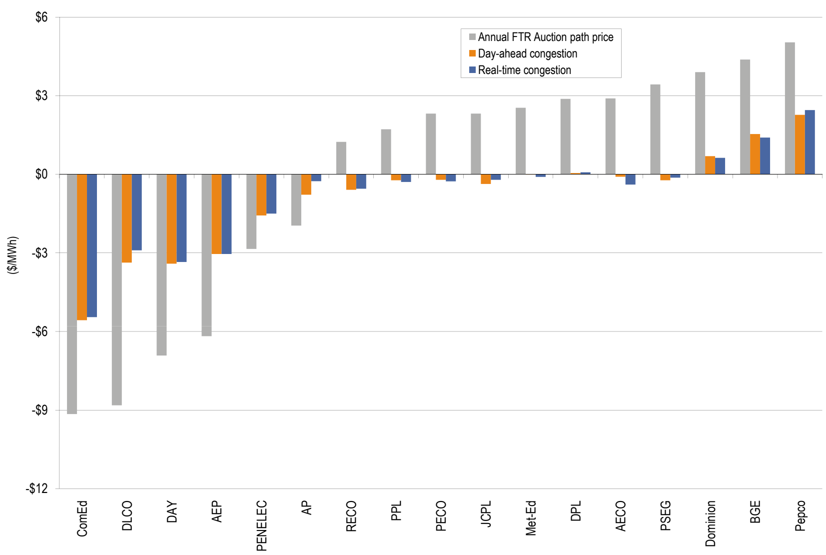
When ARRs were allocated for the 2009 to 2010 planning period, some of the requested ARRs were prorated in Stage 2 in order to ensure simultaneous feasibility. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints affecting the ARR allocation in these two stages.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-11 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2009 to 2010 planning period through December 31, 2009. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $2.32 per MWh in the Annual FTR Auction and that about -$0.21 per MWh of day-ahead congestion and -$0.27 per MWh of real-time congestion existed between the Western Hub and the PECO Control Zone. The data show that congestion costs, approximated in this way, were only positive for the Dominion, BGE and Pepco control zones and negative for all other PJM control zones. This is in contrast to prior years when congestion costs, approximated in this way, were positive for most control zones located east of the Western Hub. The Annual FTR Auction prices exceeded the price differential for every zone, again in contrast to prior years.

Figure 8-11 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2009 to 2010 through December 31, 2009



44 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 24-25.

45 See the *2009 State of the Market Report for PJM*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining the ARR prorating method.

Effectiveness of ARRs as a Hedge against Congestion

One measure of the effectiveness of ARRs as a hedge against congestion is a comparison of the revenue received by the holders of ARRs and the congestion across the corresponding paths. The revenue which serves as a hedge for ARR holders comes from the FTR auctions while the hedge for FTR holders is provided by the congestion payments derived directly from the Day-Ahead Energy Market and the balancing energy market. Thus, ARRs are an indirect hedge against actual congestion in both the Day-Ahead Energy Market and the balancing energy market.

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market is presented by control zone in Table 8-25. ARRs and self scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[46] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and, depending on market conditions, may be less than the target allocation. The FTR payout ratio equals the percentage of the target allocation that FTR holders actually receive as credits. The FTR payout ratio was 100 percent of the target allocation for the 2008 to 2009 planning period.

The “Congestion” column shows the amount of congestion in each control zone from the Day-Ahead Energy Market and the balancing energy market and includes only the congestion costs incurred by the organizations that hold ARRs or self scheduled FTRs. The last column shows the difference between the total revenue and the congestion for each ARR control zone sink.

Data shown are for the 2008 to 2009 planning period summed by ARR control zone sink. For example, the table shows that for the 2008 to 2009 planning period, ARRs allocated to the JCPL Control Zone received a total of $70.1 million in revenue which was the sum of $64.5 million in ARR credits and $5.6 million in credits for self scheduled FTRs. This total revenue was $15.7 million less than the congestion costs of $85.8 million from the Day-Ahead Energy Market and the balancing energy market incurred by organizations in the JCPL Control Zone that held ARRs or self scheduled FTRs.

46 For Table 8-25 through Table 8-28, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The “PJM” Control Zone does not include all the buses in PJM, but does include all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

Table 8-25 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2008 to 2009

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$26,640,842	$5,126,844	$31,767,686	$87,321,948	($55,554,262)	36.4%
AEP	$4,952,682	$231,856,718	$236,809,400	$210,288,401	$26,520,999	>100%
AP	$50,310,148	$512,353,151	$562,663,299	$334,688,945	$227,974,354	>100%
BGE	$93,238,869	$4,134,804	$97,373,673	$2,288,903	$95,084,770	>100%
ComEd	$15,791,877	$12,658,294	$28,450,171	$164,815,901	($136,365,730)	17.3%
DAY	$9,353,214	$1,119,768	$10,472,982	$6,769,503	$3,703,479	>100%
DLCO	$4,691,151	$0	$4,691,151	$31,730,929	($27,039,778)	14.8%
Dominion	$24,970,748	$4,221,089	$29,191,837	$48,544,486	($19,352,649)	60.1%
DPL	$6,990,231	$246,078,596	$253,068,827	$108,153,653	$144,915,174	>100%
JCPL	$64,463,301	$5,636,585	$70,099,886	$85,816,579	($15,716,693)	81.7%
Met-Ed	$220,814	$28,242,556	$28,463,370	$48,289,989	($19,826,619)	58.9%
PECO	$4,336,906	$55,831,240	$60,168,146	($18,644,822)	$78,812,968	>100%
PENELEC	$49,024,464	$24,861,452	$73,885,916	$54,514,680	$19,371,236	>100%
Pepco	$58,344,157	$648,017	$58,992,174	$289,001,211	($230,009,037)	20.4%
PJM	$10,528,746	($9,203,133)	$1,325,613	$9,855,465	($8,529,852)	13.5%
PPL	$1,841,709	$63,076,348	$64,918,057	$32,505,809	$32,412,248	>100%
PSEG	$119,733,671	$17,949,360	$137,683,031	($3,415,832)	$141,098,863	>100%
RECO	$0	$0	$0	$6,870,494	($6,870,494)	0.0%
Total	$545,433,530	$1,204,591,689	$1,750,025,219	$1,499,396,241	$250,628,978	>100%

During the 2008 to 2009 planning period, congestion costs associated with the 112,011 MW of allocated ARRs were $1,499.4 million. As Table 8-8 indicates, 72,851 MW of ARRs were converted into FTRs through the self scheduling option, with 39,160 MW remaining as ARRs. The 39,160 MW of remaining ARRs provided $545.4 million of ARR credits, representing a hedge of 36.4 percent of the $1,499.4 million in congestion costs incurred, while the self scheduled FTRs provided $1,204.6 million of revenue, hedging an additional 80.3 percent of congestion costs. Total congestion was fully hedged by both. (See Table 8-25) The effectiveness of ARRs as a hedge depends both on the ARR value which is a function of the FTR auction prices, on congestion patterns in the Day-Ahead and Real-Time Energy Markets and on the FTR payout ratio.

Effectiveness of FTRs as a Hedge against Congestion

FTRs provide a direct hedge against congestion costs. Table 8-26 compares the total FTR credits and the total FTR auction revenues that sink in each control zone and the congestion costs in each control zone for the 2008 to 2009 planning period. FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. The “FTR Credits” column represents the total FTR target allocations for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR

MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the 2007 to 2008 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any self scheduled FTRs. The FTR hedge is the difference between the FTR credits and the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the FTR hedge and the congestion for each control zone.

The total cost of all FTRs exceeded the FTR credits received, based on the value of the congestion costs for which they were purchased as a hedge. That is, after the cost to obtain the FTRs was subtracted from the total FTR revenue, the net value of all FTRs was negative and thus the FTRs were unprofitable. For example, the table shows that for the 2008 to 2009 planning period, all FTRs sunk in the Pepco Control Zone received a total of $204.6 million in FTR credits (with -$26.0 million from counter flow FTRs and $230.6 million from prevailing flow FTRs) while these FTRs cost $260.9 million in the FTR auctions (with -$52.4 million from counter flow FTRs and $313.3 million from prevailing flow FTRs) resulting in a loss of -$56.3 million. This was not the case in every control zone. For example, the FTR credits received exceeded the cost of FTRs in the AEP Control Zone. Given that the cost of FTRs exceeded the FTR credits received, FTRs did not provide a hedge against congestion for this period. In the Pepco Control Zone, the total FTR position was $206.8 million less than the cost of congestion in the Day-Ahead Energy Market and the balancing energy market. All FTRs provided a hedge of -$741.4 million against $1,422.1 million in congestion costs incurred.[47]

47 The congestion costs in Table 8-25 are the congestion costs for organizations that held ARRs while the congestion costs in Table 8-26, Table 8-27 and Table 8-28 (2008 to 2009 planning period) are the congestion costs for all organizations. The congestion costs in Table 8-25 do not equal the congestion costs in Table 8-26, Table 8-27 and Table 8-28 (2008 to 2009 planning period) because the congestion costs in Table 8-25 include congestion only for organizations that held ARRs.

Table 8-26 FTR congestion hedging by control zone: Planning period 2008 to 2009

Control Zone	FTR Direction	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
AECO	Counter Flow	($2,104,717)	($9,736,127)	$7,631,410			
	Prevailing Flow	$38,963,612	$42,669,675	($3,706,064)			
	Total	$36,858,894	$32,933,548	$3,925,346	$43,970,115	($40,044,770)	8.9%
AEP	Counter Flow	($66,608,764)	($112,426,082)	$45,817,317			
	Prevailing Flow	$276,411,670	$316,511,145	($40,099,475)			
	Total	$209,802,906	$204,085,063	$5,717,843	$155,842,889	($150,125,047)	3.7%
AP	Counter Flow	($37,785,200)	($52,972,978)	$15,187,778			
	Prevailing Flow	$565,711,180	$833,217,106	($267,505,926)			
	Total	$527,925,980	$780,244,128	($252,318,148)	$298,746,849	($551,064,997)	<0%
BGE	Counter Flow	($13,378,212)	($24,751,969)	$11,373,757			
	Prevailing Flow	$52,323,115	$81,912,465	($29,589,350)			
	Total	$38,944,903	$57,160,496	($18,215,593)	$89,929,323	($108,144,916)	<0%
ComEd	Counter Flow	($40,127,883)	($36,435,643)	($3,692,239)			
	Prevailing Flow	$13,975,621	$32,115,569	($18,139,948)			
	Total	($26,152,262)	($4,320,075)	($21,832,187)	$264,565,267	($286,397,454)	<0%
DAY	Counter Flow	($5,562,537)	($7,323,185)	$1,760,648			
	Prevailing Flow	$7,307,409	$5,296,615	$2,010,794			
	Total	$1,744,872	($2,026,571)	$3,771,443	$5,493,146	($1,721,704)	68.7%
DLCO	Counter Flow	($16,801,149)	($22,611,480)	$5,810,330			
	Prevailing Flow	$7,459,145	$6,325,094	$1,134,051			
	Total	($9,342,004)	($16,286,386)	$6,944,382	$14,972,671	($8,028,289)	46.4%
Dominion	Counter Flow	($24,949,028)	($64,995,263)	$40,046,235			
	Prevailing Flow	$369,161,337	$587,519,630	($218,358,294)			
	Total	$344,212,309	$522,524,367	($178,312,059)	$254,898,027	($433,210,086)	<0%
DPL	Counter Flow	($10,925,470)	($10,885,580)	($39,890)			
	Prevailing Flow	$61,148,336	$53,699,473	$7,448,863			
	Total	$50,222,866	$42,813,893	$7,408,973	$79,599,656	($72,190,683)	9.3%
JCPL	Counter Flow	($14,281,610)	($31,473,090)	$17,191,480			
	Prevailing Flow	$20,011,860	$135,728,462	($115,716,602)			
	Total	$5,730,251	$104,255,372	($98,525,121)	$92,985,545	($191,510,667)	<0%
Met-Ed	Counter Flow	($1,749,069)	($17,057,141)	$15,308,072			
	Prevailing Flow	$38,291,273	$77,247,955	($38,956,682)			
	Total	$36,542,204	$60,190,813	($23,648,610)	($1,271,642)	($22,376,968)	<0%
PECO	Counter Flow	($1,689,120)	($20,496,906)	$18,807,786			
	Prevailing Flow	$67,235,084	$97,218,293	($29,983,209)			
	Total	$65,545,964	$76,721,387	($11,175,423)	($47,350,955)	$36,175,533	<0%
PENELEC	Counter Flow	($51,999,686)	($96,975,856)	$44,976,170			
	Prevailing Flow	$170,697,684	$231,308,984	($60,611,300)			
	Total	$118,697,998	$134,333,128	($15,635,130)	$112,271,697	($127,906,827)	<0%
Pepco	Counter Flow	($26,020,597)	($52,417,603)	$26,397,006			
	Prevailing Flow	$230,620,973	$313,328,160	($82,707,187)			
	Total	$204,600,376	$260,910,557	($56,310,182)	$150,501,458	($206,811,640)	<0%
PJM	Counter Flow	($6,601,308)	($12,860,773)	$6,259,465			
	Prevailing Flow	$2,797,949	$15,856,630	($13,058,681)			
	Total	($3,803,359)	$2,995,857	($6,799,216)	($119,445,094)	$112,645,878	<0%
PPL	Counter Flow	($10,080,144)	($15,198,354)	$5,118,210			
	Prevailing Flow	$84,990,420	$97,234,669	($12,244,249)			
	Total	$74,910,276	$82,036,315	($7,126,039)	$4,627,831	($11,753,870)	<0%
PSEG	Counter Flow	($10,194,108)	($24,945,718)	$14,751,609			
	Prevailing Flow	$81,949,642	$173,322,349	($91,372,706)			
	Total	$71,755,534	$148,376,631	($76,621,097)	$15,850,146	($92,471,243)	<0%
RECO	Counter Flow	($99,442)	($139,574)	$40,132			
	Prevailing Flow	$103,319	$2,800,521	($2,697,202)			
	Total	$3,877	$2,660,947	($2,657,070)	$5,941,446	($8,598,516)	<0%
Total	Counter Flow	($340,958,046)	($613,703,323)	$272,745,277			
	Prevailing Flow	$2,089,159,629	$3,103,312,795	($1,014,153,166)			
	Total	$1,748,201,583	$2,489,609,472	($741,407,889)	$1,422,128,376	($2,163,536,265)	<0%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-27 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2008 to 2009 planning period. This compares the total hedge provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the price difference (sink minus source) for the ARR path from the Annual FTR Auction. The "FTR Credits" column represents the total FTR target allocation for FTRs that sink in each control zone from the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 100 percent of the target allocation for the 2008 to 2009 planning period. The "FTR Auction Revenue" column shows the amount paid for FTRs that sink in each control zone in the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR hedge is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The "Congestion" column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

The results indicate that the value of ARRs and FTRs together were higher than total congestion costs by about $130.2 million because the positive value of the ARRs exceeded the net negative value of the FTRs.

During the 2008 to 2009 planning period, the 112,011 MW of cleared ARRs produced $2,361.3 million of ARR credits while the total of all FTR credits was $1,748.2 million. Together, the ARR credits and FTR credits provided $4,109.5 million in total revenue. When calculating the total ARR and FTR hedge, the cost to obtain the FTRs must be subtracted from the total ARR and FTR revenue. This cost is the sum of the FTR auction revenues, which was $2,489.6 million for the 2008 to 2009 planning period. The total ARR and FTR value equals $1,619.9 million, which is in excess of the $1,422.1 million of congestion in the Day-Ahead Energy Market and the balancing energy market. For example, the table shows that all ARRs and FTRs that sink in the AP Control Zone received $786.1 million in ARR credits and $527.9 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $780.2 million, the total ARR and FTR hedge was $533.8 million. The total value of the ARRs and FTRs was $235.1 million higher than the $298.7 million of congestion in the Day-Ahead Energy Market and the balancing energy market.

Table 8-27 ARR and FTR congestion hedging by control zone: Planning period 2008 to 2009

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$31,771,370	$36,858,894	$32,933,548	$35,696,716	$43,970,115	($8,273,399)	81.2%
AEP	$286,629,442	$209,802,906	$204,085,063	$292,347,285	$155,842,889	$136,504,396	>100%
AP	$786,115,867	$527,925,980	$780,244,128	$533,797,719	$298,746,849	$235,050,870	>100%
BGE	$98,283,955	$38,944,903	$57,160,496	$80,068,362	$89,929,323	($9,860,961)	89.0%
ComEd	$24,695,477	($26,152,262)	($4,320,075)	$2,863,290	$264,565,267	($261,701,977)	1.1%
DAY	$9,926,586	$1,744,872	($2,026,571)	$13,698,029	$5,493,146	$8,204,883	>100%
DLCO	$4,691,151	($9,342,004)	($16,286,386)	$11,635,533	$14,972,671	($3,337,138)	77.7%
Dominion	$463,320,908	$344,212,309	$522,524,367	$285,008,850	$254,898,027	$30,110,823	>100%
DPL	$28,077,406	$50,222,866	$42,813,893	$35,486,379	$79,599,656	($44,113,277)	44.6%
JCPL	$98,171,902	$5,730,251	$104,255,372	($353,219)	$92,985,545	($93,338,764)	<0%
Met-Ed	$50,979,701	$36,542,204	$60,190,813	$27,331,092	($1,271,642)	$28,602,734	>100%
PECO	$75,104,737	$65,545,964	$76,721,387	$63,929,314	($47,350,955)	$111,280,269	>100%
PENELEC	$95,333,189	$118,697,998	$134,333,128	$79,698,059	$112,271,697	($32,573,638)	71.0%
Pepco	$59,162,442	$204,600,376	$260,910,557	$2,852,261	$150,501,458	($147,649,197)	1.9%
PJM	$20,562,228	($3,803,359)	$2,995,857	$13,763,012	($119,445,094)	$133,208,106	>100%
PPL	$73,844,704	$74,910,276	$82,036,315	$66,718,665	$4,627,831	$62,090,834	>100%
PSEG	$154,621,742	$71,755,534	$148,376,631	$78,000,645	$15,850,146	$62,150,499	>100%
RECO	$0	$3,877	$2,660,947	($2,657,070)	$5,941,446	($8,598,516)	<0%
Total	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,422,128,376	$197,756,546	>100%

Table 8-28 shows that for the 2008 to 2009 planning period, the total value of the ARR and FTR positions was $130.2 million higher than the total congestion within PJM. All ARRs and FTRs fully covered the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the first seven months of the 2009 to 2010 planning period, the FTR payout ratio was 97.7 percent of the target allocation. All ARRs and FTRs covered 93.5 percent of the total congestion costs within PJM for the first seven months of the 2009 to 2010 planning period. The total value of the ARR and FTR positions was less than the cost of congestion by $23.4 million.

Table 8-28 TARR and FTR congestion hedging: Planning periods 2008 to 2009 and 2009 to 2010[48]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2008/2009	$2,361,292,807	$1,748,201,585	$2,489,609,470	$1,619,884,922	$1,489,647,665	$130,237,257	>100%
2009/2010*	$747,598,320	$388,741,220	$799,140,566	$337,198,974	$360,608,751	($23,409,777)	93.5%

* Shows seven months ended 31-Dec-09

48 The FTR credits do not include after-the-fact adjustments. For the 2009 to 2010 planning period, the ARR credits were the total credits allocated to all ARR holders for the first seven months (June through December 2009) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first seven months of this planning period and the portion of Annual FTR Auction revenue distributed to the first seven months.

ARRs and FTRs as a Hedge against Total Real Time Energy Charges

The hedge provided by ARRs and self scheduled FTRs can also be measured by comparing the value of the ARR and self-scheduled FTRs that sink in a zone to the cost of real time energy in the zone. This is a direct measure of the net price of energy rather than a comparison of the ARR/FTR credits to an accounting measure of congestion. This is a measure of the value of the hedge against real time energy costs provided by ARRs received by loads during this period. Table 8-29 shows the results of this measure by control zone for January through December 2009. As an example, Table 8-29 shows the total value of ARR and self-scheduled FTR credits in the AP Control Zone was $204.6 million, which was 11.3 percent of the $1,815.0 in total real time energy charges in the AP Control Zone.

Table 8-29 ARRs and self-scheduled FTR credits as a hedge against energy charges by control zone: January through December, 2009

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and Self-Scheduled FTR Credits
AECO	$20,597,972	$437,541	$21,035,513	$461,146,506	4.6%
AEP	$4,561,042	$144,550,225	$149,111,267	$4,521,818,925	3.3%
AP	$47,461,725	$157,111,180	$204,572,905	$1,814,978,586	11.3%
BGE	$65,812,175	$1,640,293	$67,452,468	$1,462,148,148	4.6%
ComEd	$15,063,621	$35,377,358	$50,440,979	$2,937,210,035	1.7%
DAY	$7,508,653	$624,238	$8,132,891	$579,595,373	1.4%
DLCO	$3,377,699	$1,324	$3,379,023	$468,046,410	0.7%
Dominion	$6,488,260	$109,517,031	$116,005,290	$3,930,796,513	3.0%
DPL	$19,933,162	$962,469	$20,895,631	$795,666,592	2.6%
JCPL	$43,154,697	$2,212,990	$45,367,687	$983,469,839	4.6%
Met-Ed	$155,199	$10,011,872	$10,167,070	$634,581,943	1.6%
PECO	$2,926,977	$14,173,419	$17,100,396	$1,691,108,089	1.0%
PENELEC	$33,746,839	$9,827,605	$43,574,444	$643,838,042	6.8%
Pepco	$36,917,119	$1,021,829	$37,938,948	$1,391,452,420	2.7%
PJM	$8,886,304	($9,087,024)	($200,719)	NA	NA
PPL	$1,408,223	$12,857,478	$14,265,700	$1,686,349,753	0.8%
PSEG	$98,728,236	$4,960,710	$103,688,945	$1,900,334,329	5.5%
RECO	($24,305)	$0	($24,305)	$61,457,329	(0.0%)
Total	$416,703,596	$496,200,538	$912,904,134	$26,008,223,006	3.5%

The hedge provided by FTRs can also be measured by comparing the value of the FTRs that sink in a zone to the cost of real time energy in the zone. This is a direct measure of the net price of energy rather than a comparison of the FTR credits to an accounting measure of congestion. This is a measure of the value of the hedge against real time energy costs provided by FTRs purchased for this period. Table 8-30 shows the results of this measure by control zone for January through

December 2009. When the purchase cost of the FTRs exceeds the FTR credits, the hedge is negative.

Table 8-30 FTRs as a hedge against energy charges by control zone: January through December, 2009

Control Zone	FTR Credits (Excluding Self-Scheduled FTRs)	FTR Auction Revenue (Excluding Self-Scheduled FTRs)	Total FTR Hedge (Excluding Self-Scheduled FTRs)	Total Energy Charges	Percent of Energy Charges Covered by FTR Credits (Excluding Self-Scheduled FTRs)
AECO	$5,416,677	$24,348,793	($18,932,116)	$461,146,506	(4.1%)
AEP	$12,430,993	($32,434,705)	$44,865,698	$4,521,818,925	1.0%
AP	$19,798,820	$35,860,828	($16,062,008)	$1,814,978,586	(0.9%)
BGE	$28,212,716	$40,599,207	($12,386,491)	$1,462,148,148	(0.8%)
ComEd	$8,590,467	($7,760,858)	$16,351,326	$2,937,210,035	0.6%
DAY	$1,451,205	($1,579,623)	$3,030,828	$579,595,373	0.5%
DLCO	($1,702,295)	($9,462,717)	$7,760,422	$468,046,410	1.7%
Dominion	$19,609,059	$45,984,131	($26,375,072)	$3,930,796,513	(0.7%)
DPL	$13,767,438	$34,571,957	($20,804,519)	$795,666,592	(2.6%)
JCPL	$2,432,397	$51,098,545	($48,666,149)	$983,469,839	(4.9%)
Met-Ed	$3,262,702	$7,491,200	($4,228,498)	$634,581,943	(0.7%)
PECO	$3,116,099	$7,595,873	($4,479,775)	$1,691,108,089	(0.3%)
PENELEC	$41,509,540	$56,165,056	($14,655,516)	$643,838,042	(2.3%)
Pepco	$91,130,294	$150,832,795	($59,702,501)	$1,391,452,420	(4.3%)
PJM	$938,250	($6,595,056)	$7,533,305	NA	NA
PPL	$5,431,156	$8,745,511	($3,314,355)	$1,686,349,753	(0.2%)
PSEG	$21,897,739	$107,264,636	($85,366,897)	$1,900,334,329	(4.5%)
RECO	($510,771)	($473,088)	($37,684)	$61,457,329	(0.1%)
Total	$276,782,485	$512,252,486	($235,470,001)	$26,008,223,006	(0.9%)

Table 8-31 combines the results for the ARR related hedge and the FTR related hedge by zone. This is a measure of the total value of ARRs received by those who pay for the transmission system plus the total value of FTRs received by those who purchased FTRs in the FTR auctions. The combined ARR plus FTR credits covers the largest percentage of total energy charges in the AP Control Zone (10.4 percent), and the lowest percentage of total energy charges in the Pepco Control Zone (-1.6 percent).

Table 8-31 ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2009

Control Zone	ARR Related Hedge (Including Self-Scheduled FTRs)	FTR Hedge (Excluding Self-Scheduled FTRs)	Total ARR and FTR Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and FTR Credits
AECO	$21,035,513	($18,932,116)	$2,103,396	$461,146,506	0.5%
AEP	$149,111,267	$44,865,698	$193,976,965	$4,521,818,925	4.3%
AP	$204,572,905	($16,062,008)	$188,510,897	$1,814,978,586	10.4%
BGE	$67,452,468	($12,386,491)	$55,065,978	$1,462,148,148	3.8%
ComEd	$50,440,979	$16,351,326	$66,792,305	$2,937,210,035	2.3%
DAY	$8,132,891	$3,030,828	$11,163,719	$579,595,373	1.9%
DLCO	$3,379,023	$7,760,422	$11,139,445	$468,046,410	2.4%
Dominion	$116,005,290	($26,375,072)	$89,630,218	$3,930,796,513	2.3%
DPL	$20,895,631	($20,804,519)	$91,111	$795,666,592	0.0%
JCPL	$45,367,687	($48,666,149)	($3,298,461)	$983,469,839	(0.3%)
Met-Ed	$10,167,070	($4,228,498)	$5,938,573	$634,581,943	0.9%
PECO	$17,100,396	($4,479,775)	$12,620,622	$1,691,108,089	0.7%
PENELEC	$43,574,444	($14,655,516)	$28,918,928	$643,838,042	4.5%
Pepco	$37,938,948	($59,702,501)	($21,763,553)	$1,391,452,420	(1.6%)
PJM	($200,719)	$7,533,305	$7,332,586	NA	NA
PPL	$14,265,700	($3,314,355)	$10,951,346	$1,686,349,753	0.6%
PSEG	$103,688,945	($85,366,897)	$18,322,048	$1,900,334,329	1.0%
RECO	($24,305)	($37,684)	($61,989)	$61,457,329	(0.1%)
Total	$912,904,134	($235,470,001)	$677,434,133	$26,008,223,006	2.6%