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 *2007 State of the Market Report* focuses on two FTR/ARR planning periods: the 2006 to 2007 planning period which covers June 1, 2006, through May 31, 2007, and the 2007 to 2008 planning period which covers June 1, 2007, through May 31, 2008.

Overview

Financial Transmission Rights (FTRs)

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 administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, on-peak and off-peak periods. FTRs have

1 87 FERC ¶ 61,054 (1999).

terms varying from one month to one year. 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 Annual FTR Auction for the 2007 to 2008 planning period include the Bedington — Black Oak Interface and the Meadowbrook transformer.[2] Market participants can also sell FTRs. For the 2007 to 2008 planning period, total FTR sell offers were 117,199 MW, up from 76,669 MW during the 2006 to 2007 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2007) of the 2007 to 2008 planning period, there were 1,912,181 MW of FTR sell offers.

- Demand. There is no limit on FTR demand in any FTR auction. In the Annual FTR Auction for the 2007 to 2008 planning period, total FTR buy bids were 2,223,687 MW, up from 1,570,121 MW during the 2006 to 2007 planning period. Total FTR self-scheduled bids were 71,360 MW for the 2007 to 2008 planning period, an increase from 38,301 MW for the 2006 to 2007 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2007) of the 2007 to 2008 planning period, total FTR buy bids were 8,427,824 MW.

- FTR Credit Issues. Two participants defaulted on their FTR-related payment obligations in 2007 as the result of inadequate collateral held by PJM to cover the participants' losses resulting from counterflow FTR positions. The defaults made it clear that PJM credit polices related to FTRs and particularly to counterflow FTRs were inadequate. On December 21, 2007, PJM submitted to the United States Federal Energy Regulatory Commission (FERC) revisions to its Open Access Transmission Tariff (OATT) to improve the credit requirements for FTR market participants.[3] PJM submitted an additional filing on January 31, 2008, to the FERC to increase the credit requirement for market participants with net counterflow FTR positions.[4] The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[5] These are being investigated.

- Patterns of Ownership. Ownership of FTR products is moderately concentrated and maximum market shares exceed 20 percent in some cases based on the results of the Annual FTR Auction. The FTR options market is more concentrated than the market for FTR obligations. 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 evaluate the ownership of prevailing flow and counterflow 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. Physical entities own slightly more than half of prevailing flow FTRs while financial entities own about three quarters of counterflow FTRs. Overall, the ownership of all FTRs is about evenly split between physical and financial entities.

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 planning period. For additional information on the integrations, their timing and their impact on the footprint of the PJM service territory, see the *2007 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

3 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the PJM Credit Policy Attachment Q, Docket No. ER08-376-000 (December 26, 2007).

4 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Credit Policy Attachment Q of their Open-Access Transmission Tariff, FERC Electric Tariff, Sixth Revised Volume 1, to become effective April 1, 2008, Docket No. ER08-520-000 (January 31, 2008).

5 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

Market Performance

- Volume. For the 2007 to 2008 planning period, the Annual FTR Auction cleared 208,637 MW (9.4 percent) of FTR buy bids, up from 129,866 MW (8.3 percent of demand) for the 2006 to 2007 planning period. The Annual FTR Auction also cleared 6,495 MW (5.5 percent) of FTR sell offers for the 2007 to 2008 planning period, down from 10,056 MW (13.1 percent) for the 2006 to 2007 planning period. For the first seven months of the 2007 to 2008 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 610,829 MW (7.2 percent) of FTR buy bids and 155,606 MW (8.1 percent) of FTR sell offers. There were no direct allocation FTRs for the 2007 to 2008 planning period.

- Price. For the 2007 to 2008 planning period, 85 percent of the annual FTRs were purchased for less than $1 per MWh and 90.9 percent for less than $2 per MWh. For the 2007 to 2008 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.35 per MWh for 24-hour FTRs, $0.57 per MWh for on-peak FTRs and $0.47 per MWh for off-peak FTRs. Comparable, weighted-average prices for the 2006 to 2007 planning period were $1.95 per MWh for 24-hour and $0.78 per MWh for both on-peak and off-peak FTRs. The weighted-average prices paid for 2007 to 2008 planning period annual buy-bid FTR obligations and options were $0.47 per MWh and $0.37 per MWh, respectively, compared to $1.12 per MWh and $0.29 per MWh, respectively, in the 2006 to 2007 planning period.[6] The weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2007 to 2008 planning period was $0.18 per MWh, compared with $0.22 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2006 to 2007 planning period.

- Revenue. The Annual FTR Auction generated $1,698.03 million of net revenue for all FTRs during the 2007 to 2008 planning period, up from $1,417.5 million for the 2006 to 2007 planning period. The Monthly Balance of Planning Period FTR Auctions generated $28.2 million in net revenue for all FTRs during the first seven months of the 2007 to 2008 planning period.

- Revenue Adequacy. FTRs were 100 percent revenue adequate for the 2006 to 2007 planning period. FTRs were paid at 100 percent of the target allocation level for the first seven months of the 2007 to 2008 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,532.7 million of FTR revenues during the first seven months of the 2007 to 2008 planning period and $1,906.1 million during the 2006 to 2007 planning period. For the first seven months of the 2007 to 2008 planning period, the top sink and top source with the highest positive FTR target allocations were the AP Control Zone and the Western Hub, respectively. Similarly, the top sink and top source with the largest negative FTR target allocations were the Western Hub and Atlantic, respectively.

6 Weighted-average prices for FTRs in the 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 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 (4,080 hours) and off peak (4,680 hours).

Auction Revenue Rights (ARRs)

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 2007 to 2008 planning period were the Bedington — Black Oak and AP South interfaces. A new ARR product was added for the 2007 to 2008 planning period. Long-term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs were also introduced and 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 150,822 MW for the 2007 to 2008 planning period with 62,220 MW bid in Stage 1A, 31,063 MW bid in Stage 1B and 57,539 MW bid in Stage 2. This is up from 99,412 MW for the 2006 to 2007 planning period with 56,705 MW bid in Stage 1 and 42,707 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 10,054 MW of ARRs associated with $326,800 per MW-day of revenue that were reassigned in the first seven months of the 2007 to 2008 planning period.

Market Performance

- Volume. Of 150,822 MW in ARR requests for the 2007 to 2008 planning period, 107,992 MW (71.6 percent) were allocated. There were 62,211 MW allocated in Stage 1A, 29,444 MW allocated in Stage 1B and 16,337 MW allocated in Stage 2. Eligible market participants self-scheduled 71,360 MW (66.1 percent) of these allocated ARRs as annual FTRs. Demand for ARRs increased because of load growth and the requirement that the AEP, DAY, DLCO and Dominion control zones take ARR allocations, instead of direct allocation FTRs. Of 99,412 MW in ARR requests for the 2006 to 2007 planning period, 67,568 MW (68 percent) were allocated. There were 54,430 MW allocated in Stage 1 and 13,138 MW allocated in Stage 2. Eligible market participants self-scheduled 38,301 MW (56.7 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 2007 to 2008 planning period, ARR holders will receive $1,640 million in ARR credits, with an average hourly ARR credit of $1.73 per MWh. During the 2007 to 2008 planning period, the ARR target allocations were $1,640 million while PJM collected $1,726 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 31, 2007, making ARRs revenue adequate. During the 2006 to 2007 planning period, ARR holders received $1,405 million in ARR credits, with an average hourly ARR credit of $2.37 per MWh. For the 2006 to 2007 planning period, the ARR target allocations were $1,405 million while PJM collected $1,435 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 2007 to 2008 planning period, some of the requested ARRs were prorated as a result of binding transmission constraints. For the 2007 to 2008 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 1,159.3 MW of Stage 1B ARRs denied to participants whose requested ARRs affected that binding transmission constraint.

- ARR and FTR Revenue and 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 against the congestion costs experienced by these ARR holders. The second is to compare the revenue received by FTR holders against the total congestion costs within PJM. 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. During the 2006 to 2007 planning period, total ARR and FTR revenues hedged 98.4 percent of the congestion costs within PJM. For the first seven months of the 2007 to 2008 planning period, all ARRs and FTRs hedged 92.3 percent of the congestion costs within PJM.

Conclusion

The annual ARR allocation and the Annual FTR Auction together provide long-term, firm transmission service customers with a mechanism to hedge congestion and provide all market participants increased access to long-term FTRs. 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 2007 to 2008 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs. The rules for ARR reassignment when load shifts should address the fact that in the case of ARRs self-scheduled as FTRs, the underlying FTRs do not follow the load while the ARRs do.

ARRs were 100 percent revenue adequate for both the 2007 to 2008 and the 2006 to 2007 planning periods. FTRs were paid at 100 percent of the target allocation level for the 12-month period of the 2006 to 2007 planning period, and at 100 percent of the target allocation level for the first seven months of the 2007 to 2008 planning period. The total of ARR and FTR revenues hedged 98.4 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2006 to 2007 planning period and 92.3 percent of the congestion costs in PJM in the first seven months of the 2007 to 2008 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 FTR holders, their revenues or those paying congestion.

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.

PJM faced substantial participant defaults in 2007 as a result of participant counterflow positions in the FTR markets in combination with inadequate PJM credit requirements and inadequate participant financial resources. PJM has taken steps to address the credit issue. The defaults also raised potential market gaming issues, which were addresed, in part, in a PJM filing. These are being investigated.

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. For the 2006 to 2007 and the 2007 to 2008 planning periods, the auction covered all control zones. For the 2006 to 2007 planning period, eligible participants in the AEP, DAY, DLCO and Dominion control zones could select direct allocation FTRs or ARRs. For the 2007 to 2008 planning period, direct allocation FTRs were unavailable.

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.[7] 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, 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 should 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.

7 For additional information on marginal losses, see the *2007 State of the Market Report*, Volume II, Section 2, "Energy Market, Part 1," at "Real-Time Annual LMP Loss Component."

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 Annual FTR Auction as well as the Monthly Balance of Planning Period FTR Auctions.

Supply

The principal mechanism for obtaining FTRs is the Annual FTR Auction, including the ability to directly convert allocated ARRs into self-scheduled FTRs. A second mechanism for obtaining FTRs is the Monthly Balance of Planning Period FTR Auctions. 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, transmission outages that are expected to last for two months or more are included, while 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. FTRs can be traded between market participants through bilateral transactions. FTRs can also be obtained as direct allocation FTRs that are available to customers in recently integrated control zones.

During the 2007 to 2008 planning period, binding transmission constraints prevented the award of all requested FTRs in the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions.[8] Table 8-1 lists the top 10 binding constraints in the Annual FTR Auction along with their corresponding control zones. 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 is computed and generated in the optimization engine.[9] It is the amount of value to be gained by relieving a constraint by 1 MW.

8 Binding constraints for Monthly Balance of Planning Period Auctions are posted to the PJM Web site in monthly files at http://www.pjm.com/markets/ftr/historical-ftr-auction.jsp.

9 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 51.

Table 8-1 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2007 to 2008[10]

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Bedington - Black Oak	Interface	AP	1	1	1	1
Meadowbrook	Transformer	AP	4	2	2	3
Deepwater - Quinton	Line	AECO	2	3	3	2
Double Toll Gate - Old Chapel	Line	AP	6	4	4	4
Doubs	Transformer	AP	3	6	17	23
Waverly - Sargents	Line	AEP	5	8	6	8
Bedington - Nipetown	Line	AP	18	5	5	5
Branchburg - Readington	Line	PSEG	11	7	8	7
Bedington	Transformer	AP	NA	12	7	6
Mahans Lane - Tidd	Line	AEP	7	20	25	25

Annual FTR Auction

Each April, PJM conducts an Annual FTR Auction during which all eligible market participants can bid on FTRs for the next planning period consistent with total transmission system capability. The auction takes place over four rounds with 25 percent of the total 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.[11] 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.

10 The Bedington transformer was not constrained during the first auction round and is listed as NA (not applicable).

11 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.

Monthly Balance of Planning Period FTR Auctions

Introduced at the beginning of the 2006 to 2007 planning period, the Monthly Balance of Planning Period FTR Auctions make available the residual FTR capability on the PJM transmission system after the Annual FTR Auction is 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.[12]

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. Quarter 1 would be excluded because the auction would be held midway through the first month of quarter 1 (June) and the quarters are auctioned in three-month periods only.

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.

Direct Allocation FTRs

Direct allocation FTRs can be obtained when a new control zone is integrated into PJM. After their integration date, market participants in the new control zone have two planning periods during which they are eligible for a transitional allocation of FTRs or ARRs. After that transition, those market participants are subject to the ARR allocation rules and become ineligible for directly allocated FTRs. Like other market participants, they can still receive FTRs by self-scheduling their allocated ARRs.

12 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 34-35.

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

Two participants defaulted on their FTR-related payment obligations in 2007 as the result of inadequate collateral held by PJM to cover the participants' losses resulting from counterflow FTR positions. In October, Exel Power Sources, L.L.C. defaulted on September obligations and subsequently defaulted on additional 2007 obligations with a value of approximately $5 million. In December, Power Edge, L.L.C. defaulted on November obligations and subsequently defaulted on additional 2007 obligations with a value of approximately $21 million. Del Light, Inc. and PJS Capital, L.L.C. also defaulted in January 2008 on 2007 activity with values of approximately $0.4 million and $1 million.[13]

The defaults made it clear that PJM credit polices related to FTRs and particularly to counterflow FTRs were inadequate. The defaults also raised potential market gaming issues, which were addressed, in part, in a PJM filing.[14] These are being investigated.

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. Counterflow FTRs expose the owner to paying congestion on a path. Participants receive a payment to take counterflow FTRs with the expectation that the payment will exceed the FTR charges. 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 counterflow FTR derives from the underlying congestion and is, therefore, not limited to a fixed payment. The risk is substantially greater for a counterflow FTR than for a prevailing flow FTR.

FTR Credit Rules

Under credit rules in place during 2007, PJM required participants in FTR auctions to meet defined credit requirements linked to the value of the FTRs. PJM calculates the FTR credit requirement for each market participant using FTR cost and a measure of the historical congestion on the FTR path for the planning period, discounted by 30 percent. The 30 percent adjustment does not apply to counterflow FTRs. PJM calculates a total FTR credit requirement for each market participant, which must be maintained to participate in the FTR auctions.[15]

On December 21, 2007, PJM submitted to the FERC revisions to its OATT to improve the credit requirements for FTR market participants.[16] The revisions would change the calculation period for the FTR credit requirement to a monthly from an annual basis and would also calculate and allocate offsets for ARR credits

13 Additional information on the defaults is available on the PJM Web Site at http://www.pjm.com/services/membership/default-notification.html.

14 PJM Interconnection, L.L.C. made a filing under section 205 of the Federal Power Act to amend section 15.2 of the PJM Operating Agreement concerning defaults on short FTR portfolios in Docket No. ER08-455-000, (January 18, 2008).

15 For the complete FTR Auction credit business rules, see PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp.38-41.

16 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the PJM Credit Policy Attachment Q, Docket No. ER08-376-000 (December 26, 2007).

monthly rather than annually. The credit calculation would sum only the months with positive net credit requirements and would apply a generic 10 percent adjustment to historical values of both prevailing flow FTRs and counterflow FTRs to account for likely differences from historical experience.

PJM submitted an additional filing on January 31, 2008, to the FERC to increase the credit requirement for market participants with net counterflow FTR positions.[17] Participants with net counterflow positions have potential liabilities that are not naturally limited in the way that the liabilities of prevailing flow FTRs are limited. Participants are paid to take counterflow positions in return for making a stream of payments based on actual congestion. The credit requirements for net counterflow positions would be multiplied by two and if the counterflow position is not well diversified geographically, would be multiplied by three.

Patterns of Ownership

The overall ownership structure of FTRs and the ownership of prevailing flow and counterflow FTRs are evaluated.

The ownership concentration of cleared FTR buy bids resulting from the 2007 to 2008 Annual FTR Auction was low for FTR obligations and high for FTR options. This ownership information is only descriptive and is not 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.

For cleared FTR buy-bid obligations, the HHIs were 728 for 24-hour, 724 for on-peak and 771 for off-peak FTR products while maximum market shares were 20 percent for 24-hour, 15 percent for on-peak and 12 percent for off-peak FTR products.

For cleared FTR buy-bid options, HHIs were 2508 for 24-hour, 3185 for on-peak and 3928 for off-peak products while maximum market shares were 44 percent for 24-hour, 52 percent for on-peak and 60 percent for off-peak FTR products.

In order to evaluate the ownership of prevailing flow and counterflow 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. The MMU used available public information to categorize FTR owners and while the distinctions are not perfect, they are accurate enough to support some general conclusions. Table 8-2 presents the Annual FTR Auction market concentration for cleared FTRs in the 2007 to 2008 planning period by organization type and FTR direction. The results show that physical entities own slightly more than half of prevailing flow FTRs while financial entities own about three quarters of counterflow FTRs. Overall, the ownership of all FTRs is about evenly split between physical and financial entities.

17 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Credit Policy Attachment Q of their Open-Access Transmission Tariff, FERC Electric Tariff, Sixth Revised Volume 1, to become effective April 1, 2008, Docket No. ER08-520-000 (January 31, 2008).

Table 8-2 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2007 to 2008

	FTR Direction		
Organization Type	Prevailing Flow	Counterflow	All
Physical	57.2%	25.8%	48.9%
Financial	42.8%	74.2%	51.1%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-3 shows the Annual FTR Auction volume by trade type and auction round for the 2007 to 2008 planning period. The total volume was 2,223,687 MW for FTR buy bids and 117,199 MW for FTR sell offers for the 2007 to 2008 planning period. This is up from the total volume of 1,570,121 MW for FTR buy bids and 76,669 MW for FTR sell offers for the 2006 to 2007 planning period.

There were 208,637 MW (9.4 percent) of cleared FTR buy bids and 6,495 MW (5.5 percent) of cleared FTR sell offers for the 2007 to 2008 planning period. This is an increase from the total of 129,866 MW (8.3 percent) of cleared FTR buy bids and a decrease from 10,056 MW (13.1 percent) of cleared FTR sell offers for the 2006 to 2007 planning period.

Direct allocation FTRs were unavailable for the 2007 to 2008 planning period. For the 2006 to 2007 planning period, the total demand for direct allocation FTRs in the AEP, DAY, DLCO and Dominion control zones was 43,796 MW. There were 39,901 MW (91.1 percent) cleared, leaving 3,895 MW (8.9 percent) of uncleared direct allocation FTR requests.

Table 8-3 Annual FTR Auction market volume: Planning period 2007 to 2008

Trade Type	Auction Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	1	90,733	629,439	53,093	8.4%	576,346	91.6%
	2	91,778	656,406	60,460	9.2%	595,946	90.8%
	3	64,061	456,119	46,873	10.3%	409,246	89.7%
	4	62,949	481,723	48,211	10.0%	433,512	90.0%
	Total	309,521	2,223,687	208,637	9.4%	2,015,050	90.6%
Self-scheduled bids	1	2,672	17,840	17,840	100.0%	0	0.0%
	2	2,672	17,840	17,840	100.0%	0	0.0%
	3	2,672	17,840	17,840	100.0%	0	0.0%
	4	2,672	17,840	17,840	100.0%	0	0.0%
	Total	10,688	71,360	71,360	100.0%	0	0.0%
Buy and self-scheduled bids	1	93,405	647,279	70,933	11.0%	576,346	89.0%
	2	94,450	674,246	78,300	11.6%	595,946	88.4%
	3	66,733	473,959	64,713	13.7%	409,246	86.3%
	4	65,621	499,563	66,051	13.2%	433,512	86.8%
	Total	320,209	2,295,047	279,997	12.2%	2,015,050	87.8%
Sell offers	1	NA	NA	NA	NA	NA	NA
	2	4,535	18,771	1,489	7.9%	17,282	92.1%
	3	7,531	40,507	2,441	6.0%	38,066	94.0%
	4	9,434	57,921	2,565	4.4%	55,356	95.6%
	Total	21,500	117,199	6,495	5.5%	110,704	94.5%

Table 8-4 shows that for the 2007 to 2008 planning period, eligible market participants converted 71,360 MW of ARRs out of a possible 107,992 MW into annual FTRs. In comparison, during the 2006 to 2007 planning period, eligible market participants converted 38,301 MW of ARRs out of a possible 67,568 MW.

Table 8-4 Comparison of self-scheduled FTRs: Planning periods 2006 to 2007 and 2007 to 2008

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2006/2007	38,301	67,568	56.7%
2007/2008	71,360	107,992	66.1%

Table 8-5 shows that there were 8,427,824 MW of FTR buy bids and 1,912,181 MW of FTR sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2007 to 2008 planning period through December 31, 2007. The monthly auctions cleared 610,829 MW (7.2 percent) leaving 7,816,995 MW (92.8 percent) of uncleared FTR buy bids. There were 155,606 MW (8.1 percent) of cleared FTR sell offers leaving 1,756,575 MW (91.9 percent) of uncleared FTR sell offers.

The Monthly Balance of Planning Period FTR Auctions for the full 12-month 2006 to 2007 planning period had a total demand of 10,037,353 MW for FTR buy bids and 1,760,060 MW for FTR sell offers. The monthly auctions cleared 703,677 MW (7.0 percent) of FTR buy bids and 167,933 MW (9.5 percent) of FTR sell offers.

Table 8-5 Monthly Balance of Planning Period FTR Auction market volume: January 2007 to December 2007

Monthly Auction	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-07	Buy bids	156,611	905,249	71,628	7.9%	833,621	92.1%
	Sell offers	21,907	126,983	11,814	9.3%	115,169	90.7%
Feb-07	Buy bids	157,762	969,447	77,368	8.0%	892,079	92.0%
	Sell offers	17,279	84,494	9,189	10.9%	75,305	89.1%
Mar-07	Buy bids	152,490	799,130	83,507	10.4%	715,623	89.6%
	Sell offers	25,781	137,192	13,753	10.0%	123,439	90.0%
Apr-07	Buy bids	112,934	551,601	44,709	8.1%	506,892	91.9%
	Sell offers	18,290	96,190	13,745	14.3%	82,445	85.7%
May-07	Buy bids	105,382	480,219	46,318	9.6%	433,901	90.4%
	Sell offers	8,932	47,435	9,112	19.2%	38,323	80.8%
Jun-07	Buy bids	252,773	1,166,967	85,311	7.3%	1,081,656	92.7%
	Sell offers	58,669	383,062	35,182	9.2%	347,880	90.8%
Jul-07	Buy bids	191,960	1,068,961	80,213	7.5%	988,748	92.5%
	Sell offers	46,499	274,471	28,965	10.6%	245,506	89.4%
Aug-07	Buy bids	220,050	1,224,668	84,443	6.9%	1,140,225	93.1%
	Sell offers	52,581	280,653	21,051	7.5%	259,602	92.5%
Sep-07	Buy bids	210,234	1,200,731	91,277	7.6%	1,109,454	92.4%
	Sell offers	57,428	299,447	24,666	8.2%	274,781	91.8%
Oct-07	Buy bids	210,926	1,245,798	129,154	10.4%	1,116,644	89.6%
	Sell offers	54,458	271,862	16,727	6.2%	255,135	93.8%
Nov-07	Buy bids	180,285	1,059,631	76,970	7.3%	982,661	92.7%
	Sell offers	46,644	218,305	15,379	7.0%	202,926	93.0%
Dec-07	Buy bids	190,280	1,461,068	63,461	4.3%	1,397,607	95.7%
	Sell offers	39,124	184,381	13,636	7.4%	170,745	92.6%

Table 8-6 shows the bid and cleared volume for FTR buy bids in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2007 through December 2007.

Table 8-6 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): January 2007 to December 2007

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-07	Bid	514,491	137,697	109,648				143,413	905,249
	Cleared	52,665	8,645	3,361				6,957	71,628
Feb-07	Bid	606,601	112,492	105,954				144,400	969,447
	Cleared	64,447	4,593	3,631				4,697	77,368
Mar-07	Bid	468,987	142,103	127,507				60,533	799,130
	Cleared	61,858	10,124	8,027				3,498	83,507
Apr-07	Bid	420,473	131,128						551,601
	Cleared	37,065	7,644						44,709
May-07	Bid	480,219							480,219
	Cleared	46,318							46,318
Jun-07	Bid	338,863	175,226	165,400	87,827	134,530	137,928	127,193	1,166,967
	Cleared	36,433	11,334	12,018	4,287	7,465	7,495	6,279	85,311
Jul-07	Bid	405,059	199,897	102,256		124,838	121,543	115,368	1,068,961
	Cleared	41,262	12,572	5,896		7,623	7,147	5,713	80,213
Aug-07	Bid	498,752	106,516	98,361		169,487	179,761	171,791	1,224,668
	Cleared	43,904	6,429	6,098		8,157	10,019	9,836	84,443
Sep-07	Bid	546,318	102,371	101,203		110,568	175,115	165,156	1,200,731
	Cleared	48,276	9,642	9,115		6,004	9,705	8,535	91,277
Oct-07	Bid	561,623	186,446	103,784			202,661	191,284	1,245,798
	Cleared	94,036	11,334	6,220			8,598	8,966	129,154
Nov-07	Bid	470,466	108,359	103,673			194,265	182,868	1,059,631
	Cleared	49,571	7,578	6,000			7,812	6,009	76,970
Dec-07	Bid	512,716	281,129	275,932			262,947	128,344	1,461,068
	Cleared	38,795	7,144	5,997			3,151	8,374	63,461

Table 8-7 shows the secondary bilateral FTR market volume by hedge type and class type for the 2006 to 2007 and the 2007 to 2008 planning periods. There were 2,122 MW of total bilateral FTR activity for the 2007 to 2008 planning period while there were 6,032 MW during the 2006 to 2007 planning period. There were no option FTRs traded through the PJM secondary bilateral FTR market for the 2006 to 2007 planning period.

Table 8-7 Secondary bilateral FTR market volume: Planning periods 2006 to 2007 and 2007 to 2008[18]

Planning Period	Hedge Type	Class Type	Secondary (MW)
2006/2007	Obligation	24-hour	4,225
		On peak	958
		Off peak	849
		Total	6,032
2007/2008	Obligation	24-hour	57
		On peak	1,239
		Off peak	216
		Total	1,512
	Option	24-hour	0
		On peak	446
		Off peak	164
		Total	610

Price

Table 8-8 shows the weighted-average bid price by trade type in the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions for the 2007 to 2008 planning period.

Table 8-8 Annual and Monthly Balance of Planning Period FTR Auction weighted-average bid prices (Dollars per MWh): Planning period 2007 to 2008

	Trade Type	Average Bid Price
Annual FTR Auction	Buy bids	($0.53)
	Self-scheduled bids	NA
	Sell offers	$0.72
Monthly Balance of Planning Period FTR Auctions*	Buy bids	($0.58)
	Sell offers	$1.19

* Shows seven months ended 31-Dec-07

Table 8-9 shows the cleared, weighted-average prices by trade type, hedge type, auction round and class type for annual FTRs during the 2007 to 2008 planning period. For the 2007 to 2008 planning period, weighted-average, buy-bid FTR obligation prices were $0.47 per MWh while weighted-average, buy-bid FTR option prices were $0.37 per MWh. Comparable weighted-average prices for the 2006 to 2007 planning period were $1.12 per MWh for buy-bid FTR obligations and $0.29 per MWh for buy-bid FTR options.

18 The 2007 to 2008 planning period covers the 2007 to 2008 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through December 31, 2007.

For the 2007 to 2008 planning period, weighted-average sell offer FTR obligation prices were $0.07 per MWh while weighted-average sell offer FTR option prices were -$0.94 per MWh. Comparable weighted-average prices for the 2006 to 2007 planning period were -$0.86 per MWh for sell offer FTR obligations and -$0.15 per MWh for sell offer FTR options.

On average during the 2007 to 2008 planning period in the Annual FTR Auction, self-scheduled FTRs were priced $1.47 per MWh higher than buy-bid obligation FTRs. They were also priced $0.83 per MWh lower than the cleared, weighted-average price of self-scheduled FTRs during the 2006 to 2007 planning period.

Table 8-9 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning period 2007 to 2008

			Class Type			
Trade Type	Hedge Type	Auction Round	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	1	$0.09	$0.69	$0.61	$0.47
		2	$0.52	$0.36	$0.26	$0.39
		3	$0.44	$0.56	$0.53	$0.51
		4	$0.32	$0.70	$0.56	$0.54
		Total	$0.35	$0.57	$0.47	$0.47
	Options	1	$0.15	$0.75	$0.18	$0.45
		2	$0.22	$0.53	$0.30	$0.37
		3	$0.44	$0.72	$0.19	$0.42
		4	$0.05	$0.49	$0.19	$0.28
		Total	$0.23	$0.61	$0.21	$0.37
Self-scheduled bids	Obligations	1	$1.93	NA	NA	$1.93
		2	$1.96	NA	NA	$1.96
		3	$1.95	NA	NA	$1.95
		4	$1.93	NA	NA	$1.93
		Total	$1.94	NA	NA	$1.94
Buy and self-scheduled bids	Obligations	1	$1.28	$0.69	$0.61	$1.02
		2	$1.40	$0.36	$0.26	$0.95
		3	$1.55	$0.56	$0.53	$1.18
		4	$1.52	$0.70	$0.56	$1.18
		Total	$1.43	$0.57	$0.47	$1.07
Sell offers	Obligations	1	NA	NA	NA	NA
		2	($0.13)	$0.42	$0.24	$0.09
		3	$0.53	$0.18	$0.25	$0.26
		4	($1.05)	$0.29	$0.60	($0.11)
		Total	($0.43)	$0.28	$0.39	$0.07
	Options	1	NA	NA	NA	NA
		2	($0.13)	($4.61)	($2.52)	($4.06)
		3	$0.53	($0.24)	($0.20)	($0.22)
		4	($0.83)	($0.66)	($0.08)	($0.30)
		Total	($0.83)	($1.58)	($0.35)	($0.94)

The 2007 to 2008 planning period price duration curve for cleared buy bids in Figure 8-1 shows that 85 percent of annual FTRs were purchased for less than $1 per MWh, 90.9 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.

Figure 8-1 Annual FTR auction-clearing price duration curve: Planning period 2007 to 2008

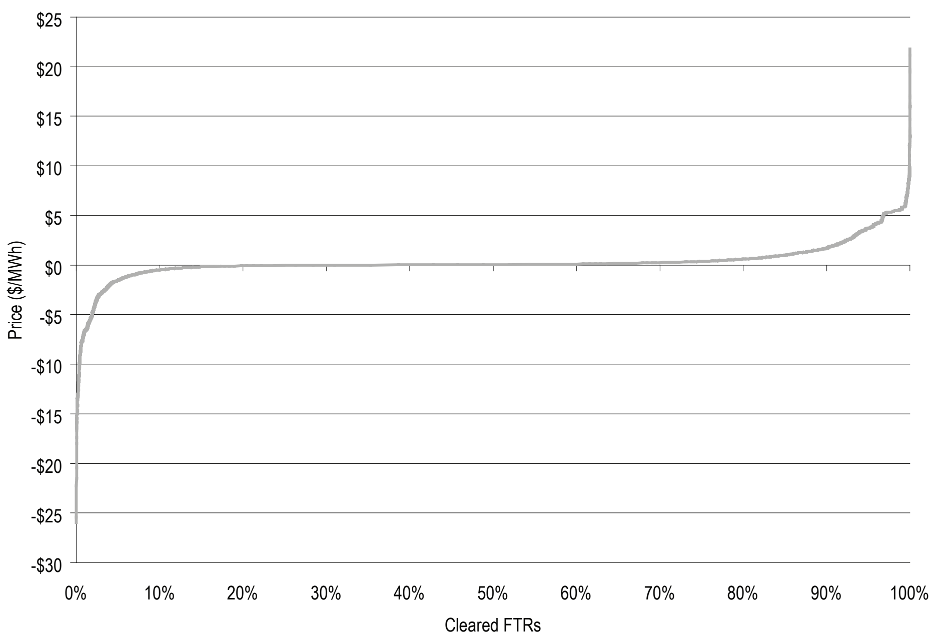


Table 8-10 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2007 through December 2007. For example, for the June 2007 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month 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 2007 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 2007 to 2008 planning period was $0.18 per MWh, compared with $0.22 per MWh for the full 12-month 2006 to 2007 planning period.

Table 8-10 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): January 2007 to December 2007

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-07	$0.13	$0.20	($0.06)				$0.45	$0.14
Feb-07	$0.03	$0.13	$0.02				$0.19	$0.07
Mar-07	$0.05	($0.15)	($0.16)				$0.84	$0.11
Apr-07	$0.15	$0.19						$0.16
May-07	$0.11							$0.11
Jun-07	$0.14	$0.33	($0.09)	$0.45	($0.03)	$0.28	$0.09	$0.16
Jul-07	$0.32	$0.92	$0.06		$0.26	$0.41	$0.51	$0.41
Aug-07	$0.19	$0.33	$0.17		$0.14	$0.28	$0.29	$0.23
Sep-07	$0.12	$0.23	$0.11		($0.06)	$0.22	$0.09	$0.12
Oct-07	$0.06	$0.18	$0.01			$0.24	$0.16	$0.11
Nov-07	$0.10	($0.22)	$0.03			$0.34	$0.10	$0.13
Dec-07	$0.05	$0.19	$0.24			$0.25	$0.13	$0.12

Revenue

Annual FTR Auction Revenue

Table 8-11 shows Annual FTR Auction revenue data by trade type, auction round and class type. For the 2007 to 2008 planning period, the Annual FTR Auction netted $1,698.03 million in revenue, with buyers paying $1,698.28 million and sellers receiving $0.25 million. For the 2006 to 2007 planning period, the Annual FTR Auction netted $1,417.5 million in revenue, with buyers paying $1,453 million and sellers receiving $35.5 million.

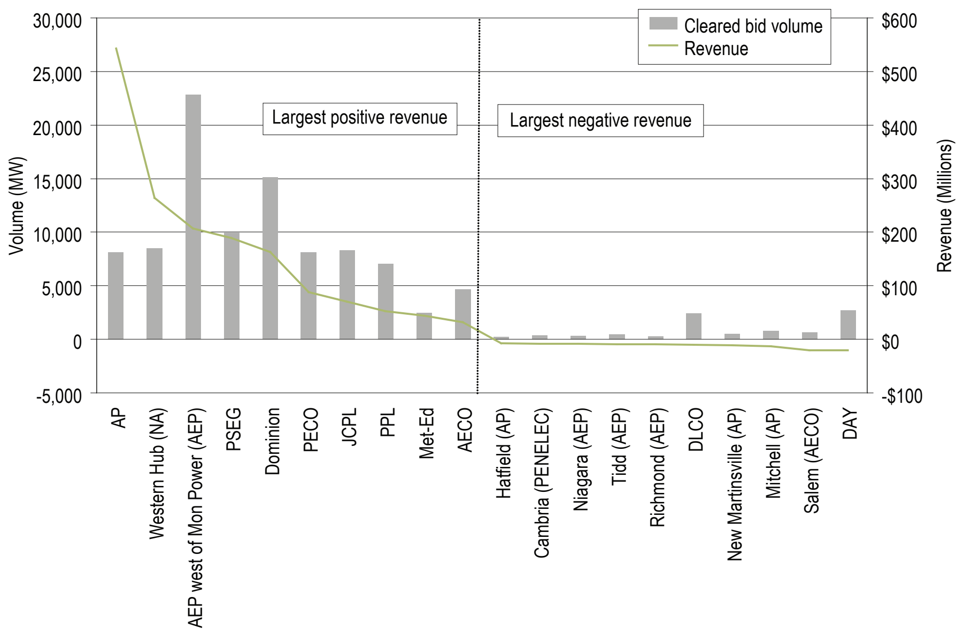
Table 8-11 Annual FTR Auction revenue: Planning period 2007 to 2008

		Class Type			
Trade Type	Auction Round	24-Hour	On Peak	Off Peak	All
Buy bids	1	$8,446,917	$73,952,697	$45,070,233	$127,469,847
	2	$54,204,137	$40,426,599	$28,626,993	$123,257,729
	3	$27,360,401	$52,798,932	$35,302,820	$115,462,153
	4	$17,004,914	$59,503,404	$38,714,096	$115,222,414
	Total	$107,016,369	$226,681,632	$147,714,142	$481,412,143
Self-scheduled bids	1	$302,959,854	NA	NA	$302,959,854
	2	$306,899,628	NA	NA	$306,899,628
	3	$305,327,391	NA	NA	$305,327,391
	4	$301,683,335	NA	NA	$301,683,335
	Total	$1,216,870,208	NA	NA	$1,216,870,208
Buy and self-scheduled bids	1	$311,406,771	$73,952,697	$45,070,233	$430,429,701
	2	$361,103,765	$40,426,599	$28,626,993	$430,157,357
	3	$332,687,792	$52,798,932	$35,302,820	$420,789,544
	4	$318,688,249	$59,503,404	$38,714,096	$416,905,749
	Total	$1,323,886,577	$226,681,632	$147,714,142	$1,698,282,351
Sell offers	1	NA	NA	NA	NA
	2	($595,128)	($427,175)	($35,394)	($1,057,697)
	3	$816,645	$721,027	$967,389	$2,505,061
	4	($4,782,618)	$1,002,334	$2,087,605	($1,692,679)
	Total	($4,561,101)	$1,296,186	$3,019,600	($245,315)

Figure 8-2 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 2007 to 2008 planning period.[19] The top 10 positive revenue producing FTR sinks accounted for $1,653.9 million (97.4 percent) of the total revenue of $1,698.03 million paid in the auction. They also comprised 33.2 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 -$117.2 million of revenue and constituted 2.9 percent of all FTRs bought in the auction.

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

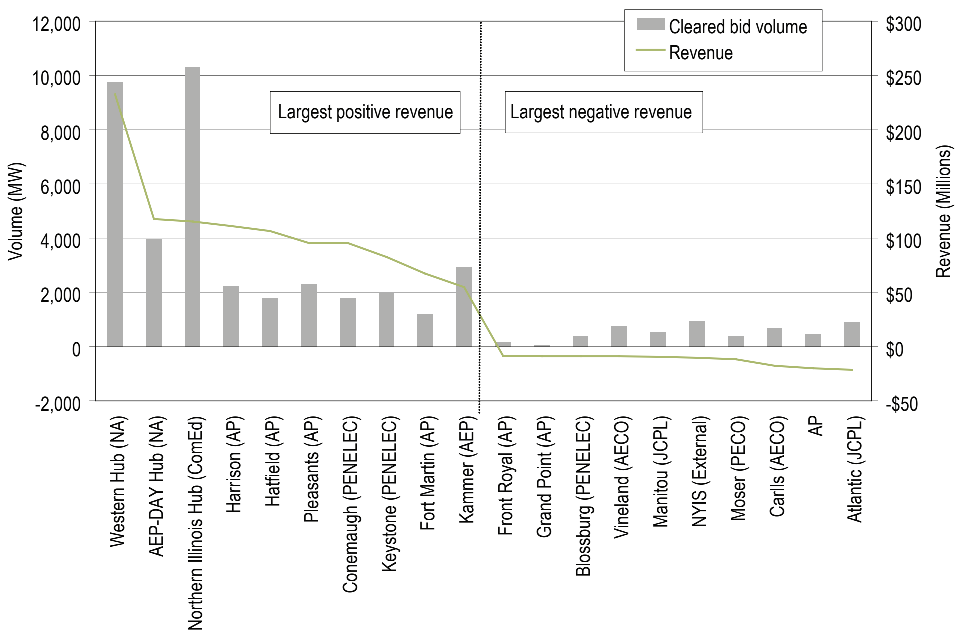
Figure 8-2 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2007 to 2008[20]



20 For Figure 8-2 through Figure 8-7, each FTR sink and source that is not a control zone has its corresponding control zone listed in parenthesis after its name. Most FTR sink and source control zone identifications for hubs; interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-3 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 2007 to 2008 planning period. The top 10 positive revenue producing FTR sources accounted for $1,077.8 million (63.5 percent) of the total revenue of $1,698.03 million paid in the auction. They also comprised 13.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$125.4 million of revenue and constituted 1.8 percent of all FTRs bought in the auction.

Figure 8-3 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2007 to 2008



Monthly Balance of Planning Period FTR Auction Revenue

Table 8-12 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type and class type. For the 2007 to 2008 planning period through December 31, 2007, the Monthly Balance of Planning Period FTR Auctions netted $28.2 million in revenue, with buyers paying $62.2 million and sellers receiving $34 million. For the 2006 to 2007 planning period, the Monthly Balance of Planning Period FTR Auctions netted $17.2 million in revenue, with buyers paying $71.2 million and sellers receiving $54 million.

Table 8-12 Monthly Balance of Planning Period FTR Auction revenue: January 2007 to December 2007

Monthly Auction	Trade Type	Class Type			
		24-Hour	On Peak	Off Peak	All
Jan-07	Buy bids	$583,017	$2,883,069	$964,794	$4,430,880
	Sell offers	($721,226)	($2,090,817)	($328,769)	($3,140,812)
Feb-07	Buy bids	($3,768,019)	$3,399,267	$2,400,432	$2,031,680
	Sell offers	($649,464)	($1,072,643)	$25,121	($1,696,986)
Mar-07	Buy bids	$1,656,411	$712,695	$1,198,393	$3,567,499
	Sell offers	($567,082)	($915,103)	($1,277,279)	($2,759,464)
Apr-07	Buy bids	($505,488)	$1,974,040	$1,085,023	$2,553,575
	Sell offers	($303,963)	($1,043,921)	($547,857)	($1,895,741)
May-07	Buy bids	$259,746	$1,043,126	$631,131	$1,934,003
	Sell offers	($360,056)	($717,855)	($307,251)	($1,385,162)
Jun-07	Buy bids	$7,101,255	$690,771	$218,269	$8,010,295
	Sell offers	($3,941,208)	$1,022,876	($1,207,028)	($4,125,360)
Jul-07	Buy bids	$5,164,135	$10,221,230	$3,343,105	$18,728,470
	Sell offers	($3,224,602)	($7,530,502)	($2,793,025)	($13,548,129)
Aug-07	Buy bids	$1,904,748	$8,485,750	$2,981,821	$13,372,319
	Sell offers	($1,574,195)	($4,719,109)	($1,074,102)	($7,367,406)
Sep-07	Buy bids	$982,636	$4,564,365	$1,016,093	$6,563,094
	Sell offers	($991,670)	($2,912,997)	$525,664	($3,379,003)
Oct-07	Buy bids	($245,677)	$5,902,053	$1,068,982	$6,725,358
	Sell offers	($1,816,099)	($2,050,370)	$1,304,930	($2,561,539)
Nov-07	Buy bids	($1,729,412)	$4,654,263	$1,978,845	$4,903,696
	Sell offers	($2,195,950)	($848,295)	$1,173,866	($1,870,379)
Dec-07	Buy bids	$765,152	$1,935,346	$1,234,802	$3,935,300
	Sell offers	($921,537)	($376,631)	$165,582	($1,132,586)

Figure 8-4 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 2007 to 2008 planning period. The top 10 positive revenue producing FTR sinks accounted for $99.5 million of revenue and 8.2 percent of all FTRs bought in the Monthly Balance of Planning Period FTR Auctions. There were 6,132 MW cleared out of 32,697 MW bid for FTRs sunk into the new Neptune 230 kV line which generated $6.3 million of revenue. The top 10 negative revenue producing FTR sinks accounted for -$36.7 million of revenue and constituted 6.4 percent of all FTRs bought in the auctions.

Figure 8-4 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2007 to 2008 through December 31, 2007

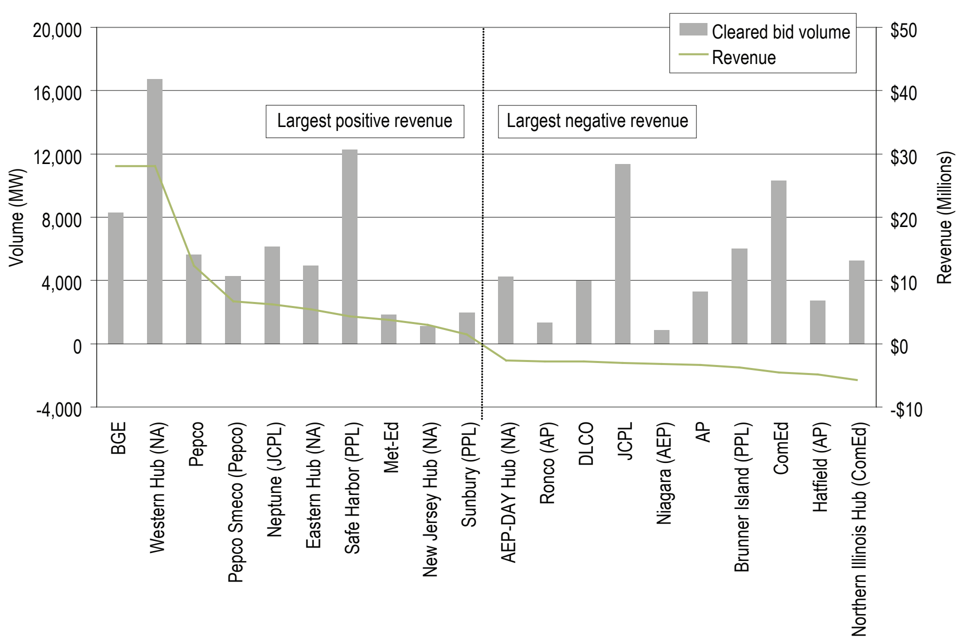
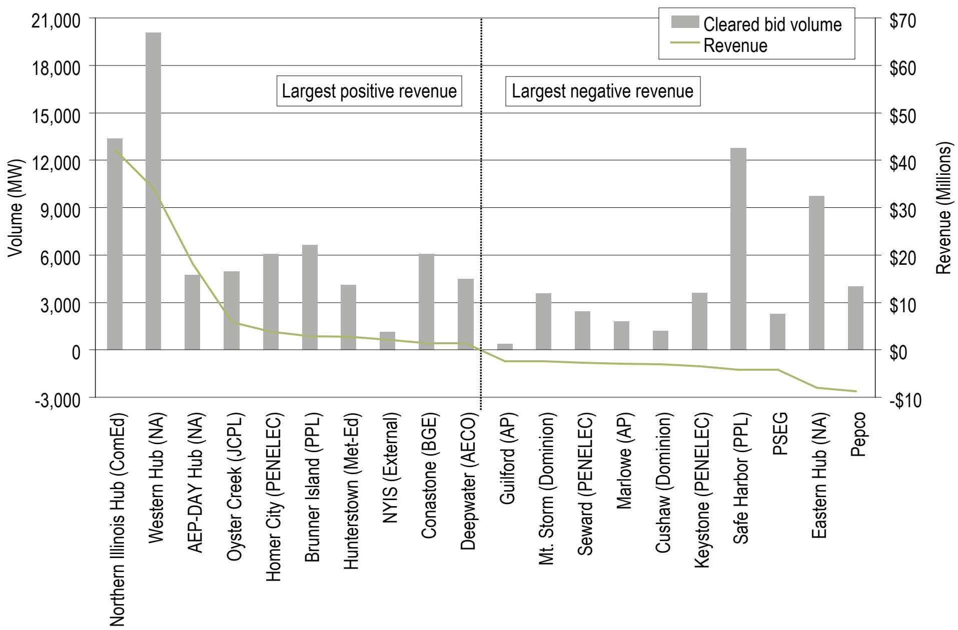


Figure 8-5 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2007 to 2008 planning period. The top 10 positive revenue producing FTR sources accounted for $114.8 million and 9.3 percent of all FTRs bought in the auctions. The top 10 negative revenue producing FTR sources accounted for -$42.1 million of revenue and constituted 5.4 percent of all FTRs bought in the auctions.

Figure 8-5 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2007 to 2008 through December 31, 2007



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 congested price and all load in the constrained area pays the congested price. As a result, load congestion payments are usually greater than the congestion-related increase in payments to generation.[21] 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.

21 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," *2007 State of the Market Report*, Volume II, Appendix G, "Financial Transmission and Auction Revenue Rights."

Table 8-13 shows the composition of FTR target allocations and FTR revenues for the 2006 to 2007 and the 2007 to 2008 planning periods, with the latter shown through December 31, 2007. 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 8-13 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.[22] 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 $1.4 million in congestion charges to Con Edison in the 2007 to 2008 planning period through December 31, 2007.[23, 24]

22 See "Joint Operating Agreement between the Midwest Independent System Operator, Inc. and PJM Interconnection, L.L.C." (December 31, 2003), Substitute Original Sheet No. 66 <http://www.pjm.com/documents/downloads/agreements/joa-complete.pdf> (1,331 KB).

23 111 FERC ¶ 61,228 (2005).

24 See the *2007 State of the Market Report*, Volume II, Section 4, "Interchange Transactions," at "Con Edison and PSE&G Wheeling Contracts 2007 Update" and Appendix D, "Interchange Transactions" at Table D-1, "Con Edison and PSE&G wheel settlements data: Calendar year 2007."

Table 8-13 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2006 to 2007 and 2007 to 2008

Accounting Element	2006/2007	2007/2008*
ARR information		
ARR target allocations	$1,392.8	$959.9
FTR auction revenue	$1,434.8	$1,009.5
ARR excess	$41.9	$49.6
FTR targets		
FTR target allocations	$1,724.8	$1,197.9
Adjustments:		
Adjustments to FTR target allocations	($1.8)	($2.5)
Total FTR targets	$1,723.0	$1,195.5
FTR revenues		
ARR excess	$41.9	$49.6
Competing uses	$0.8	$0.4
Hourly congestion revenue		
Day ahead	$1,878.7	$1,345.3
Balancing	($155.9)	($144.5)
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	$1.1	($8.8)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison	($2.6)	($1.4)
Adjustments:		
Excess revenues carried forward into future months	$138.8	$296.9
Excess revenues distributed back to previous months	$6.6	$0.0
Other adjustments to FTR revenues	($2.9)	$0.5
Total FTR revenues	$1,906.1	$1,532.7
Excess revenues distributed to other months	($183.1)	($337.3)
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to firm demand holders	$37.5	$0.0
Total FTR congestion credits	$1,723.0	$1,195.5
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$1,763.3	$1,196.8
Remaining deficiency	$0.0	$0.0
* Shows seven months ended 31-Dec-07		

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 8-14 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 2006 to 2007 planning period and the 2007 to 2008 planning period through December 31, 2007.

Table 8-14 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2006 to 2007 and 2007 to 2008

		FTR Revenues	FTR Target Allocations	FTR Credits	FTR Payout Ratio	Credits Deficiency	Credits Excess
Planning period 2006 to 2007	Jun-06	$167.8	$167.8	$167.8	100%	$0	$0.0
	Jul-06	$298.4	$293.8	$293.8	100%	$0	$4.6
	Aug-06	$374.0	$368.0	$368.0	100%	$0	$6.0
	Sep-06	$78.8	$75.2	$75.2	100%	$0	$3.6
	Oct-06	$47.1	$45.1	$45.1	100%	$0	$2.0
	Nov-06	$49.9	$44.2	$44.2	100%	$0	$5.7
	Dec-06	$100.7	$92.1	$92.1	100%	$0	$8.6
	Jan-07	$125.8	$106.4	$106.4	100%	$0	$19.4
	Feb-07	$198.4	$175.4	$175.4	100%	$0	$23.0
	Mar-07	$186.4	$147.3	$147.3	100%	$0	$39.1
	Apr-07	$151.7	$118.3	$118.3	100%	$0	$33.4
	May-07	$127.1	$89.4	$89.4	100%	$0	$37.7
	Total	$1,906.1	$1,723.0	$1,723.0	100%	$0	$183.1
	Values after excess revenues distributed						
		$1,906.1	$1,723.0	$1,723.0	100%	$0	$183.1
Planning period 2007 to 2008 (through December 31, 2007)	Jun-07	$193.0	$178.1	$178.1	100%	$0	$14.9
	Jul-07	$227.9	$178.9	$178.9	100%	$0	$49.0
	Aug-07	$264.8	$206.3	$206.3	100%	$0	$58.5
	Sep-07	$199.0	$134.2	$134.2	100%	$0	$64.8
	Oct-07	$192.0	$130.6	$130.6	100%	$0	$61.4
	Nov-07	$180.4	$132.0	$132.0	100%	$0	$48.4
	Dec-07	$275.6	$235.4	$235.4	100%	$0	$40.2
	Total	$1,532.7	$1,195.5	$1,195.5	100%	$0	$337.2

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 2007 to 2008 planning period through December 31, 2007. Figure 8-6 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 66.3 percent of total positive target allocations during the first seven months of the 2007 to 2008 planning period. FTRs with the AP Control Zone as the sink included 22.2 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 19.8 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 3.5 percent of all negative target allocations.

Figure 8-6 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2007 to 2008 through December 31, 2007

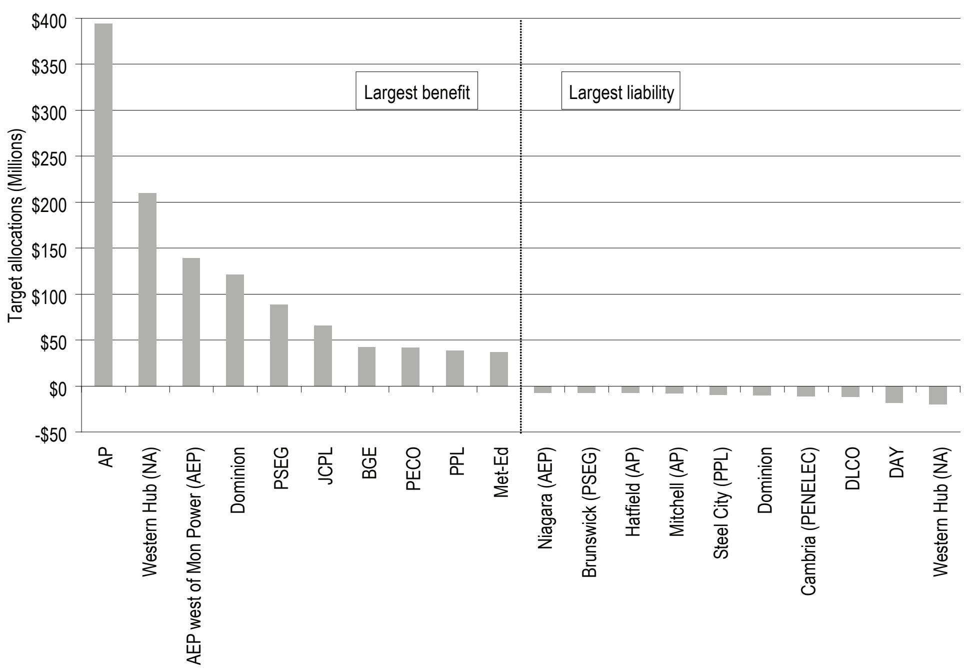
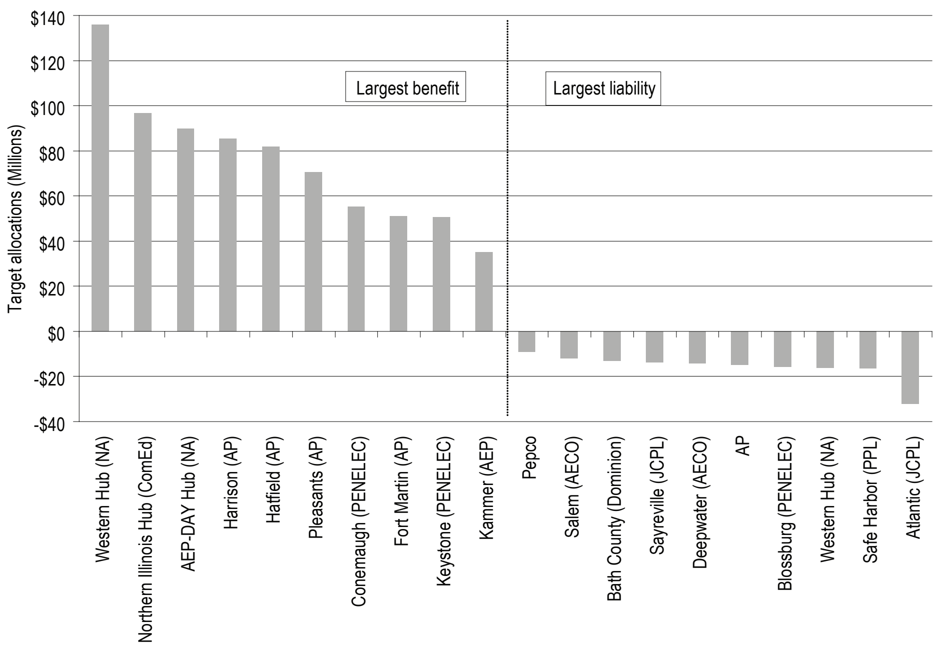


Figure 8-7 shows the FTR sources with the largest positive and negative target allocations during the first seven months of the 2007 to 2008 planning period. The top 10 sources with a positive target allocation accounted for 42.3 percent of total positive target allocations. FTRs with the Western Hub as their source included 7.6 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 27 percent of total negative target allocations. FTRs with Atlantic as the source encompassed 5.5 percent of all negative target allocations.

Figure 8-7 Ten largest positive and negative FTR target allocations summed by source: Planning period 2007 to 2008 through December 31, 2007



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.[25] 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.

25 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.

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 their target allocations if total net revenues from the 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 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 planning period, 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

On July 20, 2006, the FERC issued an order amending its regulations under the Federal Power Act to require transmission organizations that are public utilities with organized electricity markets to make available long-term, firm transmission rights that satisfy certain conditions imposed by the final rule.[26] Before its issuance, PJM had, on July 3, 2006, submitted to the FERC revisions to its OATT to include long-term ARRs and FTRs for a duration of 10 planning periods.[27] On November 22, 2006, the FERC issued an order accepting the revisions to the PJM OATT with the stipulation that they were subject to some modifications to include an uplift mechanism to ensure that long-term ARRs and FTRs would be fully funded.[28]

26 116 FERC ¶ 61,077 (2006).

27 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended and Restated Operating Agreement, Docket No. ER06-1218-000 (July 3, 2006).

28 117 FERC ¶ 61,220 (2006).

On January 22, 2007, in compliance with the FERC order, PJM submitted revisions to its OATT so as to include an uplift mechanism that would fully fund all FTRs and ARRs.[29] PJM proposed to fully fund all ARRs and FTRs by allocating uplift charges on a pro-rata basis corresponding to a market participant's FTR target allocations in proportion to the sum of all market participant's FTR target allocations. On May 17, 2007, the FERC issued an order accepting these revisions while encouraging PJM to continue to explore all possible options for an uplift mechanism and requiring it to file a status report by November 30, 2007.[30] On October 22, 2007, the FERC issued an order on clarification of the May 17 order indicating that negative FTR target allocations be excluded from the uplift mechanism.[31] PJM submitted to the FERC on November 16, 2007, revisions to the OATT to exclude negative FTR target allocations from the uplift mechanism.[32] PJM filed a status report with the FERC on November 30, 2007, that stated that an alternative to the existing uplift mechanism could not be agreed upon and, therefore, the OATT would remain the same.[33] PJM will fully fund all ARRs and FTRs by allocating uplift charges on a pro-rata basis corresponding to a market participant's net positive FTR target allocations in proportion to the sum of all market participant's net positive FTR target allocations.

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:

- 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 baseload, 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.

29 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. in compliance with the FERC's November 22, 2006, order submitted revisions to Schedule 1 of the Amended and Restated Operating Agreement, Docket No. ER06-1218-003 (January 22, 2007).

30 119 FERC ¶ 61,144 (2007).

31 121 FERC ¶ 61,073 (2007).

32 *PJM Interconnection, L.L.C.*, PJM Interconnection, L.L.C. submits revisions to the Amended & Restated Operating Agreement of PJM Interconnection, L.L.C. & its OATT to prevent the allocation of transmission rights uplift charges etc, Docket No. ER06-1218-006 (November 16, 2007).

33 *PJM Interconnection, L.L.C.*, PJM filed an informational report describing the transmission rights underfunding uplift charge allocation alternatives evaluated in the PJM stakeholder process and the results of that process, Docket No. ER06-1218-007 (November 30, 2007).

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 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 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

35 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 20-23.

36 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 48-49.

37 See the *2007 State of the Market Report*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

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.

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 maintained.

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).

40 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 28.

Table 8-15 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 2007 to 2008 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 8-15 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2007 to 2008

Constraint	Type	Control Zone
Bedington - Black Oak	Interface	AP
AP South	Interface	AP
Meadowbrook	Transformer	AP
Cedar Grove - Clifton	Line	PSEG
Whitpain	Transformer	PECO
East Frankfort - Goodings Grove	Line	ComEd
Coneprep	Transformer	AEP
Barbadoes - Plymouth Meeting	Line	PECO
Glasgow - Mount Pleasant	Line	DPL
Manor - South Akron	Line	PPL

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

41 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 48-49.

42 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), pp. 16-17.

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. When load shifts from one LSE to another in newly integrated control zones, directly allocated FTRs with positive economic value follow the load.[44]

Table 8-16 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2006 and December 2007. About 10,054 MW of ARRs associated with $326,800 per MW-day of revenue were automatically reassigned in the first seven months of the 2007 to 2008 planning period. About 20,633 MW of ARRs with $381,300 per MW-day of revenue were reassigned for the entire 12-month 2006 to 2007 planning period.

Table 8-16 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2006, to December 31, 2007

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2006/2007 (12 months)	2007/2008 (7 months)*	2006/2007 (12 months)	2007/2008 (7 months)*
AECO	151	142	$5.9	$3.8
AEP	267	27	$1.5	$1.1
AP	384	909	$79.5	$166.8
BGE	5,833	2,260	$143.0	$58.4
ComEd	7,282	2,428	$7.5	$5.6
DAY	4	0	$0.0	$0.0
DLCO	809	293	$3.2	$0.4
Dominion	2	21	$0.1	$0.0
DPL	1,132	1,096	$15.8	$15.4
JCPL	437	423	$9.9	$8.3
Met-Ed	420	3	$19.7	$0.1
PECO	111	34	$4.2	$1.2
PENELEC	175	3	$8.3	$0.1
Pepco	2,662	1,513	$50.0	$34.2
PPL	21	9	$1.0	$0.3
PSEG	936	879	$31.7	$31.0
RECO	7	14	$0.0	$0.1
Total	20,633	10,054	$381.3	$326.8
* Through 31-Dec-07				

43 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 26.
44 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 33.

Market Performance

Volume

Table 8-17 lists the annual ARR allocation volume by stage and round for the 2006 to 2007 and the 2007 to 2008 planning periods. For the 2007 to 2008 planning period, there were 62,220 MW (41.25 percent of total demand) bid in Stage 1A, 31,063 MW (20.60 percent of total demand) bid in Stage 1B and 57,539 MW (38.15 percent of total demand) bid in Stage 2. Of 150,822 MW in total ARR requests, 62,211 MW were allocated in Stage 1A and 29,444 MW were allocated in Stage 1B while 16,337 MW were allocated in Stage 2 for a total of 107,992 MW (71.6 percent) allocated. Eligible market participants subsequently converted 71,360 MW of these allocated ARRs into annual FTRs (66.1 percent of total allocated ARRs), leaving 36,632 MW of ARRs outstanding. For the 2006 to 2007 planning period, there had been 56,705 MW (57 percent of total demand) bid in Stage 1 and 42,707 MW (43 percent of total demand) bid in Stage 2. Of 99,412 MW in total ARR requests, 54,430 MW were allocated in Stage 1 while 13,138 MW were allocated in Stage 2 for a total of 67,568 MW (68 percent) allocated. There were 38,301 MW or 56.7 percent of the allocated ARRs converted into FTRs. Immediately after the Stage 1B ARR allocation for the 2007 to 2008 planning period, ARR holders relinquished 9.6 MW of the allocated Stage 1A ARRs and 459.7 MW of the allocated Stage 1B ARRs. In comparison, no ARRs were relinquished after the Stage 1 ARR allocation for the 2006 to 2007 planning period. The uncleared volume in Table 8-17 includes ARRs that were relinquished.

Demand for ARRs increased because of load growth and the requirement for the AEP, DAY, DLCO and Dominion control zones to select ARR allocations, instead of direct allocation FTRs.

Table 8-17 Annual ARR allocation volume: Planning periods 2006 to 2007 and 2007 to 2008

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2006/2007	1	0	7,294	56,705	54,430	96.0%	2,275	4.0%
	2	1	1,445	11,610	3,518	30.3%	8,092	69.7%
		2	847	9,929	3,367	33.9%	6,562	66.1%
		3	670	10,374	3,076	29.7%	7,298	70.3%
		4	617	10,794	3,177	29.4%	7,617	70.6%
		Total	3,579	42,707	13,138	30.8%	29,569	69.2%
	Total		10,873	99,412	67,568	68.0%	31,844	32.0%
2007/2008	1A	0	7,578	62,220	62,211	100.0%	9	0.0%
	1B	1	3,486	31,063	29,444	94.8%	1,619	5.2%
	2	2	1,922	19,360	4,043	20.9%	15,317	79.1%
		3	1,466	19,312	5,211	27.0%	14,101	73.0%
		4	1,072	18,867	7,083	37.5%	11,784	62.5%
		Total	4,460	57,539	16,337	28.4%	41,202	71.6%
	Total		15,524	150,822	107,992	71.6%	42,830	28.4%

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 $1,640 million in credits from the Annual FTR Auction during the 2007 to 2008 planning period, with an average hourly ARR credit of $1.73 per MWh. During the comparable 2006 to 2007 planning period, ARR holders received $1,405 million in ARR credits, with an average hourly ARR credit of $2.37 per MWh.

Table 8-18 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 and the 2007 to 2008 (through December 31, 2007) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for both planning periods. The 2007 to 2008 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $86 million in auction net revenue through December 31, 2007, above the amount needed to pay 100 percent of ARR target allocations. The whole 2006 to 2007 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $30 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-18 ARR revenue adequacy (Dollars (Millions)): Planning periods 2006 to 2007 and 2007 to 2008

	2006/2007	2007/2008
Total FTR auction net revenue	$1,435	$1,726
Annual FTR Auction net revenue	$1,418	$1,698
Monthly Balance of Planning Period FTR Auction net revenue*	$17	$28
ARR target allocations	$1,405	$1,640
ARR credits	$1,405	$1,640
Surplus auction revenue	$30	$86
ARR payout ratio	100%	100%
FTR payout ratio*	100%	100%
* Shows 12 months for 2006/2007 and seven months ended 31-Dec-07 for 2007/2008		

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.[45, 46]

When ARRs were allocated for the 2007 to 2008 planning period, some of the requested ARRs were prorated in order to ensure simultaneous feasibility. There were no ARRs prorated in Stage 1A of the annual ARR allocation. The Cedar Grove — Clifton line was the only binding constraint in Stage 1B of the annual ARR allocation, leading to 1,159.3 MW of proration.

A number of factors caused the proration of requested ARRs on the Cedar Grove — Clifton line. They include an increase in ARR requests for congested paths on the Cedar Grove — Clifton line, general load growth and increased unscheduled transmission flow across the PJM system from external sources.

ARR and FTR Revenue and Congestion

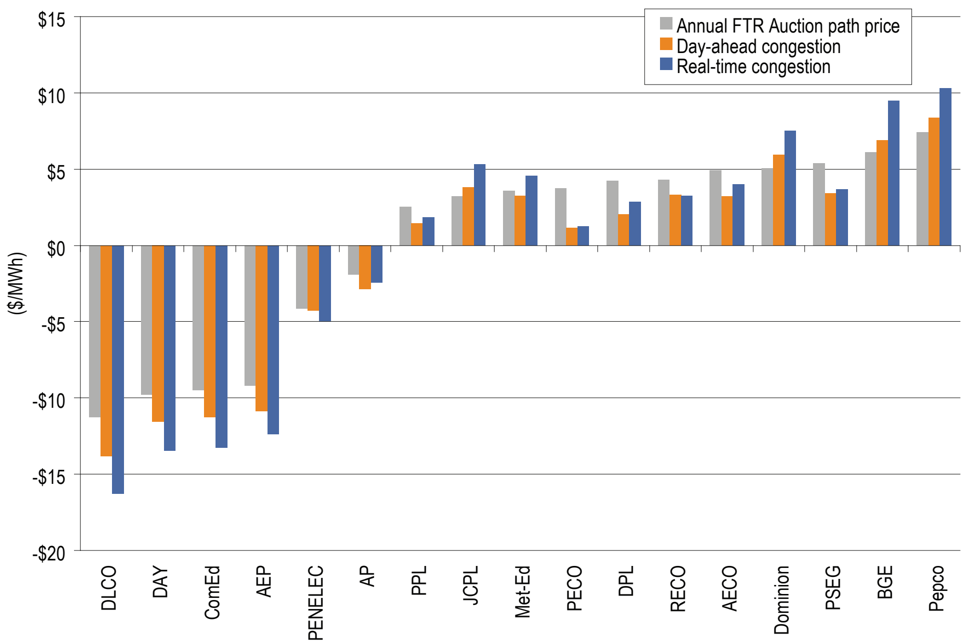
FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-8 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2007 to 2008 planning period through December 31, 2007. 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 $3.74 per MWh in the Annual FTR Auction and that about $1.17 per MWh of day-ahead congestion and $1.26 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 positive for most control zones that are located east of the Western Hub while congestion costs were negative and were more negative than the negative price of FTRs for control zones that are located west of that hub.

45 PJM. "Manual 6: Financial Transmission Rights," Revision 10 (June 1, 2007), p. 25.

46 See the *2007 State of the Market Report*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining the ARR prorating method.

Figure 8-8 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2007 to 2008 through December 31, 2007



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 8-19. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[47] 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.

47 For Table 8-19 through Table 8-22, aggregates are separated into their individual bus components and each bus is assigned to a control zone. Aggregates that are external sinks are included in the PJM Control Zone.

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 2006 to 2007 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 2006 to 2007 planning period summed by ARR control zone sink. For example, the table shows that for the 2006 to 2007 planning period, ARRs allocated to the JCPL Control Zone received a total of $48.8 million in revenue which was the sum of $38.5 million in ARR credits and $10.3 million in credits for self-scheduled FTRs. This total revenue was $99.6 million less than the congestion costs of $148.4 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.

Table 8-19 ARR and self-scheduled FTR congestion hedging by control zone: Planning period 2006 to 2007

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$37,960,325	$2,545,194	$40,505,519	$98,562,187	($58,056,668)	41.1%
AEP	$5,849,312	$1,972,819	$7,822,131	$195,769,926	($187,947,795)	4.0%
AP	$66,054,626	$560,001,705	$626,056,331	$306,893,885	$319,162,446	204.0%
BGE	$60,435,545	$3,949,724	$64,385,269	$72,164,905	($7,779,636)	89.2%
ComEd	$5,586,175	$19,654,286	$25,240,461	$38,177,869	($12,937,408)	66.1%
DAY	$2,050,472	$45,910	$2,096,382	$10,600,806	($8,504,424)	19.8%
DLCO	$2,157,721	$9,469	$2,167,190	$7,185,829	($5,018,639)	30.2%
Dominion	$38,516,691	$15,528,297	$54,044,988	$891,430,187	($837,385,199)	6.1%
DPL	$19,230,662	$7,073,286	$26,303,948	$94,773,192	($68,469,244)	27.8%
JCPL	$38,456,684	$10,348,818	$48,805,502	$148,371,543	($99,566,041)	32.9%
Met-Ed	$5,822,196	$39,098,770	$44,920,966	$74,507,634	($29,586,668)	60.3%
PECO	$11,326,155	$73,368,203	$84,694,358	($41,674,855)	$126,369,213	>100%
PENELEC	$13,454,376	$32,296,616	$45,750,992	$99,627,192	($53,876,200)	45.9%
Pepco	$41,376,839	$3,380,679	$44,757,518	$311,422,014	($266,664,496)	14.4%
PJM	$4,173,240	$2,655,850	$6,829,090	($52,528)	$6,881,618	>100%
PPL	$4,090,906	$47,202,269	$51,293,175	($19,251,625)	$70,544,800	>100%
PSEG	$118,913,460	$12,244,774	$131,158,234	$76,759,705	$54,398,529	170.9%
RECO	$1,443,947	$0	$1,443,947	$12,331,680	($10,887,733)	11.7%
Total	$476,899,332	$831,376,669	$1,308,276,001	$2,377,599,546	($1,069,323,545)	55.0%

During the 2006 to 2007 planning period, congestion costs associated with the 67,568 MW of allocated ARRs were $2,377.6 million. As Table 8-4 indicates, 38,301 MW of ARRs were converted into FTRs through the self-scheduling option, with 29,267 MW remaining as ARRs. The 29,267 MW of remaining ARRs provided $476.9 million of ARR credits, representing a hedge of 20 percent of the $2,377.6 million in congestion costs incurred, while the self-scheduled FTRs provided $831.4 million of revenue, hedging an additional 35 percent of congestion costs. Total congestion hedged by both was $1,308.3 million, or 55.0 percent. (See Table 8-19.) 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 8-20 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 2006 to 2007 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 2006 to 2007 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.

All FTRs provided a hedge of $290.1 million against $1,722.8 million in congestion costs incurred.[48] This demonstrates that all FTRs provided a 16.8 percent hedge against congestion costs in PJM. For example, the table shows that for the 2006 to 2007 planning period, all FTRs sunk in the Pepco Control Zone received a total of $141.8 million in FTR credits while these FTRs cost $132.3 million in the FTR auctions. This gives a total FTR hedge of $9.5 million against $201.2 million in congestion costs from the Day-Ahead Energy Market and the balancing energy market. This shows a deficit of $191.7 million in their total FTR hedge position versus the cost of congestion in the Day-Ahead Energy Market and the balancing energy market. It would not be expected that the value of the FTR hedge calculated in this manner would cover all congestion costs as both ARRs and FTRs are available to hedge total congestion. That comparison is provided in Table 8-21.

48 The congestion costs in Table 8-20, Table 8-21 and Table 8-22 (2006 to 2007 planning period) do not equal the congestion costs in Table 8-19 because the congestion costs for organizations that did not hold ARRs had negative congestion costs that lowered the total congestion costs compared to those of just the ARR holders.

Table 8-20 FTR congestion hedging by control zone: Planning period 2006 to 2007

Control Zone	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference	Percent Hedged
AECO	$42,768,075	$60,230,082	($17,462,007)	$67,085,194	($84,547,201)	< 0%
AEP	$164,687,852	($35,943,010)	$200,630,862	$166,314,810	$34,316,052	120.6%
AP	$569,068,207	$572,185,631	($3,117,424)	$420,202,812	($423,320,236)	< 0%
BGE	$44,177,535	$44,624,675	($447,140)	$105,375,274	($105,822,414)	< 0%
ComEd	$18,451,540	($9,118,361)	$27,569,901	$135,684,232	($108,114,331)	20.3%
DAY	$2,073,735	($6,460,296)	$8,534,031	$11,743,208	($3,209,177)	72.7%
DLCO	($6,381,093)	($21,902,476)	$15,521,383	$49,965,737	($34,444,354)	31.1%
Dominion	$243,308,757	$44,156,816	$199,151,941	$280,205,524	($81,053,583)	71.1%
DPL	$40,790,763	$44,464,780	($3,674,017)	$99,543,825	($103,217,842)	< 0%
JCPL	$41,450,855	$68,688,063	($27,237,208)	$113,257,858	($140,495,066)	< 0%
Met-Ed	$58,987,745	$50,447,353	$8,540,392	$18,714,551	($10,174,159)	45.6%
PECO	$90,294,949	$128,528,732	($38,233,783)	($55,606,384)	$17,372,601	68.8%
PENELEC	$69,419,846	$79,169,254	($9,749,408)	$120,583,245	($130,332,653)	< 0%
Pepco	$141,801,096	$132,288,429	$9,512,667	$201,191,153	($191,678,486)	4.7%
PJM	$18,234,521	$10,571,744	$7,662,777	($76,889,434)	$84,552,211	< 0%
PPL	$51,180,375	$71,887,428	($20,707,053)	($32,339,599)	$11,632,546	64.0%
PSEG	$131,199,665	$198,188,719	($66,989,054)	$85,602,232	($152,591,286)	< 0%
RECO	$3,309,712	$2,744,571	$565,141	$12,121,505	($11,556,364)	4.7%
Total	$1,724,824,135	$1,434,752,134	$290,072,001	$1,722,755,743	($1,432,683,742)	16.8%

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-21 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 2006 to 2007 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 sink-minus-source price difference 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 2006 to 2007 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 less than total congestion costs by about $28 million. During the 2006 to 2007 planning period, the 67,568 MW of cleared ARRs produced $1,404.6 million of ARR credits while the total of all FTR credits was $1,724.8 million. Together, the ARR credits and FTR credits provided approximately $3,129.5 million in total ARR and FTR 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 total sum of the FTR auction revenues which was $1,434.8 million for the 2006 to 2007 planning period. The total ARR and FTR hedge equals $1,694.7 million, a hedge of 98.4 percent of $1,722.8 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 $651.2 million in ARR credits and $569.1 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $572.2 million, the total ARR and FTR hedge was $648.1 million. Their total hedge was $227.9 million higher than the $420.2 million of congestion in the Day-Ahead Energy Market and the balancing energy market.

Table 8-21 ARR and FTR congestion hedging by control zone: Planning period 2006 to 2007

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$41,133,569	$42,768,075	$60,230,082	$23,671,562	$67,085,194	($43,413,632)	35.3%
AEP	$11,313,430	$164,687,852	($35,943,010)	$211,944,292	$166,314,810	$45,629,482	127.4%
AP	$651,180,242	$569,068,207	$572,185,631	$648,062,818	$420,202,812	$227,860,006	154.2%
BGE	$65,120,212	$44,177,535	$44,624,675	$64,673,072	$105,375,274	($40,702,202)	61.4%
ComEd	$8,862,245	$18,451,540	($9,118,361)	$36,432,146	$135,684,232	($99,252,086)	26.9%
DAY	$2,148,066	$2,073,735	($6,460,296)	$10,682,097	$11,743,208	($1,061,111)	91.0%
DLCO	$2,304,673	($6,381,093)	($21,902,476)	$17,826,056	$49,965,737	($32,139,681)	35.7%
Dominion	$60,102,387	$243,308,757	$44,156,816	$259,254,328	$280,205,524	($20,951,196)	92.5%
DPL	$24,817,167	$40,790,763	$44,464,780	$21,143,150	$99,543,825	($78,400,675)	21.2%
JCPL	$52,986,630	$41,450,855	$68,688,063	$25,749,422	$113,257,858	($87,508,436)	22.7%
Met-Ed	$50,448,008	$58,987,745	$50,447,353	$58,988,400	$18,714,551	$40,273,849	315.2%
PECO	$114,251,938	$90,294,949	$128,528,732	$76,018,155	($55,606,384)	$131,624,539	>100 %
PENELEC	$53,844,756	$69,419,846	$79,169,254	$44,095,348	$120,583,245	($76,487,897)	36.6%
Pepco	$44,747,368	$141,801,096	$132,288,429	$54,260,035	$201,191,153	($146,931,118)	27.0%
PJM	$12,103,102	$18,234,521	$10,571,744	$19,765,879	($76,889,434)	$96,655,313	>100 %
PPL	$72,426,920	$51,180,375	$71,887,428	$51,719,867	($32,339,599)	$84,059,466	>100 %
PSEG	$135,412,323	$131,199,665	$198,188,719	$68,423,269	$85,602,232	($17,178,963)	79.9%
RECO	$1,443,947	$3,309,712	$2,744,571	$2,009,088	$12,121,505	($10,112,417)	16.6%
Total	$1,404,646,983	$1,724,824,135	$1,434,752,134	$1,694,718,984	$1,722,755,743	($28,036,759)	98.4%

Table 8-22 shows that for the 2006 to 2007 planning period, the total ARR and FTR hedge was $28 million less than the total congestion within PJM. All ARRs and FTRs hedged approximately 98.4 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the first seven months of the 2007 to 2008 planning period, all ARRs and FTRs hedged 92.3 percent of the total congestion costs within PJM. The total ARR and FTR hedge position was less than the cost of congestion by $92.7 million.

Table 8-22 ARR and FTR congestion hedging: Planning periods 2006 to 2007 and 2007 to 2008[49]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2006/2007	$1,404,646,983	$1,724,824,135	$1,434,752,134	$1,694,718,984	$1,722,755,743	($28,036,759)	98.4%
2007/2008*	$1,640,453,406	$1,193,886,008	$1,726,169,098	$1,108,170,316	$1,200,838,156	($92,667,840)	92.3%

* Shows seven months ended 31-Dec-07

49 The FTR credits do not include after-the-fact adjustments.