SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

Financial Transmission Rights (FTRs) and Auction Revenue Rights (ARRs) give firm transmission customers an offset against congestion costs. An FTR provides holders revenues, or charges, equal to the difference in prices in the Day-Ahead Energy Market across the specific FTR transmission path. An ARR is a related product that provides holders 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 firm transmission 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 firm point-to-point and network service transmission customers as a hedge against congestion costs since the inception of locational marginal pricing (LMP) on April 1, 1998.[1] Effective June 1, 2003, PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.[2] Firm transmission customers can take allocated ARRs or the underlying FTRs through a process called self-scheduling.

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

The *2006 State of the Market Report* focuses on two FTR/ARR planning periods: the 2005 to 2006 planning period which covers June 1, 2005, through May 31, 2006, and the 2006 to 2007 planning period which covers June 1, 2006, through May 31, 2007.[3]

Analysis of 2006 market results requires comparison to prior years. During calendar years 2004 and 2005, PJM integrated five new control zones. When making comparisons to 2004 and 2005, the *2006 State of the Market Report* refers to three phases in calendar year 2004 and two phases in 2005 that correspond to those integrations.[4]

1 PJM network and firm long-term point-to-point transmission service customers are referred to as eligible customers.

2 87 FERC ¶ 61,054 (1999).

3 Annual FTR accounting changed from calendar year to planning period beginning with the 2003 to 2004 planning period. Transition to this new accounting period required that 2003 calendar year accounting be extended by five months and encompass January 1, 2003, through May 31, 2004.

4 For additional information on PJM's footprint and the definition of these phases, see *2006 State of the Market Report*, Volume II, Appendix A, "PJM Geography."

Overview

Financial Transmission Rights (FTRs)

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. In addition to the Annual FTR Auction, PJM conducts regular 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.[5] FTR products include FTR obligations and FTR options. Each of these is available for 24-hour, on-peak and off-peak periods. FTRs have terms varying from one month to one year. PJM submitted to the United States Federal Energy Regulatory Commission (FERC) revisions to the PJM Open Access Transmission Tariff (OATT) to include long-term ARRs and FTRs that would be in effect for 10 planning periods.[6] Long-term FTRs would be obtained by directly converting long-term ARRs into self-scheduled FTRs. 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 2006 to 2007 planning period include the Laurel–Woodstown line and the Bedington-Black Oak Interface. Prorating of FTRs is in direct proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.

- **Demand.** There is no limit on FTR demand in any FTR auction. 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 years following their integration date. In the Annual FTR Auction for the 2006 to 2007 planning period, total demand was 1,608,422 MW, up from 871,841 MW during the 2005 to 2006 planning period. The Annual FTR Auction cleared 168,167 MW (10.5 percent of demand), leaving 1,440,255 MW (89.5 percent of demand) of uncleared bids. In the monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2006) of the 2006 to 2007 planning period, the total demand was 6,331,707 MW. The monthly Balance of Planning Period FTR Auctions cleared 380,147 MW (6 percent of demand), leaving 5,951,560 MW (94 percent of demand) of uncleared bids.

- **Market Concentration.** 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. Given PJM's Annual and monthly Balance of Planning Period FTR Auctions, the market shares may fluctuate when FTR-owning entities trade, buy or sell the instruments. 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.

5 The monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 planning period are referred to as Monthly FTR Auctions in any figure, table or text that also contains data for Monthly FTR Auctions prior to June 2006.

6 *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).

Market Performance

- **Volume.** Of 1,652,218 MW in annual FTR requests, including FTR allocations, for the 2006 to 2007 planning period, 208,068 MW (12.6 percent) were cleared. Of 914,483 MW in annual FTR requests for the 2005 to 2006 planning period, 180,608 MW (19.7 percent) were cleared. This volume included the demand and supply for directly allocated FTRs for the AEP, DAY, DLCO and Dominion Control Zones.

- **Price.** For the 2006 to 2007 planning period, 87.2 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 91.5 percent for less than $2 per MWh. For the 2006 to 2007 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $1.95 per MWh for 24-hour FTRs and $0.78 per MWh for both on-peak and off-peak FTRs. Comparable, weighted-average prices for the 2005 to 2006 planning period were $1.63 per MWh for 24-hour, $0.45 per MWh for on-peak and $0.19 per MWh for off-peak FTRs. The weighted-average prices paid for 2006 to 2007 planning period annual buy-bid FTR obligations and options were $1.12 per MWh and $0.29 per MWh, respectively, compared to $0.79 per MWh and $0.21 per MWh, respectively, in the 2005 to 2006 planning period.[7] The weighted-average price paid in the monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2006) of the 2006 to 2007 planning period was $0.29 per MWh, compared with $0.23 per MWh in the Monthly FTR Auctions for the 2005 to 2006 planning period.

- **Revenue.** Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $1,117 million of FTR revenues during the first seven months (June through December 2006) of the 2006 to 2007 planning period and $2,219 million during the 12-month 2005 to 2006 planning period.[8]

- **Revenue Adequacy.** FTRs were 91 percent revenue adequate for the 2005 to 2006 planning period. FTRs were paid at 100 percent of the target allocation level for the first seven months (June through December 2006) of the 2006 to 2007 planning period.[9] For the first seven months of the 2006 to 2007 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 the Eastern Hub, respectively.

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 ARRs that are feasible.

7 Weighted-average prices for FTRs in the Annual FTR Auction and monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 planning period 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 for the 2006 to 2007 planning period 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).

8 See *2006 State of the Market Report,* Volume II, Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."

9 See *2006 State of the Market Report,* Volume II, Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period" for an additional discussion of FTR revenue adequacy.

PJM submitted to the FERC revisions to the PJM OATT to include long-term ARRs for a duration of 10 planning periods.[10]

- **Demand.** Total demand in the annual ARR allocation was 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. This is up from 84,088 MW for the 2005 to 2006 planning period with 50,955 MW bid in Stage 1 and 33,133 MW bid in Stage 2.[11] ARR demand is limited by the total amount of network and long-term, 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 zone is allocated a proportional share of positively valued ARRs within the zone based on the shifted load. There were 15,358 MW of ARRs associated with $307,500 per MW-day of revenue that were reassigned in the first seven months (June through December 2006) of the 2006 to 2007 planning period.

Market Performance

- **Volume.** 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. Demand for ARRs increased because of load growth and the eligibility of the ComEd Control Zone to take ARR allocations, instead of direct allocation FTRs. Of 84,088 MW in ARR requests for the 2005 to 2006 planning period, 59,410 MW (70.7 percent) were allocated. There were 49,577 MW allocated in Stage 1 and 9,833 MW allocated in Stage 2. Eligible market participants self-scheduled 32,631 MW (54.9 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 2005 to 2006 planning period, ARR holders received $870 million in ARR credits, with an average hourly ARR credit of $1.67 per MWh. During the 2005 to 2006 planning period, the ARR target allocations were $870 million while PJM collected $898 million from the combined Annual and Monthly FTR Auctions, making ARRs revenue adequate. During the 2006 to 2007 planning period, ARR holders will receive $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 $1,432 million from the combined Annual and monthly Balance of Planning Period FTR Auctions through the end of calendar year 2006, making ARRs revenue adequate.

- **ARR Proration Issues.** When ARRs were allocated for the 2006 to 2007 planning period, some of the

10 *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).

11 The demand for the 2005 to 2006 planning period was listed as 82,343 MW in the *2005 State of the Market Report*. This number excluded individual ARR bid requests that did not clear any MW.

requested ARRs were prorated as a result of binding transmission constraints. For the 2006 to 2007 planning period, one of the major constraints affecting the allocation of ARRs was the Bedington-Black Oak Interface which usually has power flow from the west to the east. Over 700 MW of Stage 1 ARRs were denied to participants whose requested ARRs affected that transmission constraint. On August 1, 2006, two municipalities, the Borough of Chambersburg, Pennsylvania, and the Town of Front Royal, Virginia, filed a complaint with the FERC for review of the proration of their requested ARRs.[12] PJM filed an answer to the complaint on August 23, 2006.[13] The FERC denied the complaint on November 22, 2006.[14]

- **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 and Balancing Energy Market within PJM. During the 2005 to 2006 planning period, total ARR and FTR revenues hedged 99 percent of the congestion costs within PJM. For the first seven months (June through December 2006) of the 2006 to 2007 planning period, all ARRs and FTRs hedged 98.4 percent of the congestion costs within PJM.

Conclusion

The annual ARR allocation and the Annual FTR Auction together provide long-term, firm transmission 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 Market results for the 2006 to 2007 planning year 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 ARR does. ARRs were 100 percent revenue adequate for both the 2005 to 2006 and the 2006 to 2007 planning periods. FTRs were paid at 91 percent of the target allocation level for the 12-month period of the 2005 to 2006 planning period, and at 100 percent of the target allocation level for the first seven months (June through December 2006) of the 2006 to 2007 planning period. The total of ARR and FTR revenues hedged 99 percent of the congestion costs in the Day-Ahead and Balancing Energy Market within PJM for the 2005 to 2006 planning period and 98.4 percent of the congestion costs in PJM in the first seven months of the 2006 to 2007 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

12 *Front Royal, Town of*, Complaint of the Borough of Chambersburg, PA, and the Town of Front Royal, VA, against PJM Interconnection, L.L.C., Docket No. EL06-94-000 (August 1, 2006).

13 *Front Royal, Town of*, Answer of PJM Interconnection, L.L.C. to complaint, Docket No. EL06-94-000 (August 23, 2006).

14 117 FERC ¶ 61,219 (2006).

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.

Financial Transmission Rights

While FTRs have been available to eligible participants since the 1998 introduction of LMPs, the Annual FTR Auction was first implemented for the 2003 to 2004 planning period. For the 2006 to 2007 planning period, the auction covered all control zones. Eligible participants in the AEP, DAY, DLCO and Dominion Control Zones received transitional, direct allocation FTRs at their option.[15]

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational price differences in the Day-Ahead Energy Market. The FTR target allocation is equal to the product of the FTR MW and the price differences between sink and source that occur in the Day-Ahead Energy Market. That price difference is also known as congestion. The value of an FTR can be positive or negative depending on these sink-minus-source price differences, with negative differences resulting in a liability for the holder.

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 based on their target allocations. When FTR holders receive their target allocation, 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.

There are two types of FTR product: FTR obligations and FTR options. An FTR obligation provides a credit, positive or negative, equal to the product of the FTR MW and the price difference between FTR sink and source that occurs in the Day-Ahead Energy Market. An FTR option provides only positive credits.

There are three standard FTR obligation and option 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) Monday through Friday, excluding North American Electric Reliability Council (NERC) holidays. The off-peak products are effective during all other periods.

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 qualified market participants can participate in the Annual FTR Auction as well as the monthly Balance of Planning Period FTR Auctions. In addition, auction market participants are free to request FTRs between any pricing nodes on the system, not just from designated capacity resources to network load or solely along a long-term, firm point-to-point transmission service path.

15 AEP and DAY joined PJM on October 1, 2004. DLCO joined PJM on January 1, 2005. Dominion joined PJM on May 1, 2005.

Supply

The principal mechanism for obtaining FTRs is the Annual FTR Auction, including the ability to directly convert allocated ARRs into self-scheduled FTRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, 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 also be obtained as direct allocation FTRs (available to customers in recently integrated control zones), in monthly Balance of Planning Period FTR Auctions and via bilateral trades of existing FTRs.

During the 2006 to 2007 planning period, binding constraints prevented the award of all requested FTRs in the Annual FTR Auction. Table 8-1 lists the top 10 binding constraints in order of severity, which is determined by the marginal value of the binding constraint. The marginal value is computed and generated in the optimization engine.[16] It is the amount of value to be gained by relieving a constraint by 1 MW.

Table 8-1 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2006 to 2007[17]

Constraint	Type	Control Zone
Laurel - Woodstown	Line	AECO
Bedington - Black Oak	Interface	AP
Mitchell - Shepler Hill	Line	AP
Wylie Ridge	Transformer	AP
Mount Storm - Doubs	Line	AP
Kammer	Transformer	AEP
5004/5005 Interface	Interface	NA
Bedington - Nipetown	Line	AP
Mahans Lane - Tidd	Line	AEP
Cedar Grove - Clifton	Line	PSEG

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 as follows:

- **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

16 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), p. 52.

17 The constraint control zone identification for the 5004/5005 Interface is listed as NA (not applicable) because it cannot be assigned to a specific control zone.

maximizing the net revenue based on offer-based value of FTRs.[18] Auction participation is not restricted to any class of customers, and any market participant can make offers 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 FTRs. 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.

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 and allow market participants 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.[19]

Under the new auction rules, market participants may bid to buy or offer to sell FTRs that have the following 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 timeframe). 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 first month of quarter 1 (June) would have passed and the quarters are auctioned in three-month periods only.

18 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.

19 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 34-35.

Long-Term FTRs

On July 3, 2006, PJM submitted to the FERC revisions to the OATT to include long-term ARRs and FTRs with a duration of 10 planning periods.[20] Long-term FTRs would be obtained by directly converting long-term ARRs into self-scheduled FTRs. Long-term ARR holders could opt out of any planning period during the 10-planning-period timeline and self-schedule their long-term ARRs as FTRs. Long-term ARRs and FTRs would give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10-planning-period-timeframe. The submission included an effective date of March 1, 2007, which would allow enough time to include long-term ARRs and FTRs for the 2007 to 2008 planning period. On November 22, 2006, the FERC issued an order accepting the revisions to the PJM OATT with the stipulation that they are subject to some modifications.[21]

Demand

Under the current rules, participants may submit unlimited bids for FTRs.

In addition to the Annual and monthly Balance of Planning Period FTR Auctions, FTRs can be traded between market participants through bilateral transactions. Eligible participants can trade FTRs through the PJM-administered, bilateral market, or market participants can trade FTRs among themselves without PJM involvement. Bilateral activity has increased from year to year since 2003.

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 years following their integration date. After the two year transition period, such participants receive ARRs from the annual allocation process and are ineligible for directly allocated FTRs. Like other participants, they can receive FTRs by self-scheduling their allocated ARRs. For the 2006 to 2007 planning period (June 1, 2006, through May 31, 2007), ARR allocations were provided to eligible market participants in the Mid-Atlantic Region, and AP and ComEd Control Zones. The choice of ARRs or direct allocation FTRs was available in the recently integrated AEP, DAY, DLCO and Dominion Control Zones. Table 8-2 summarizes the availability of ARRs and direct allocation FTRs within the different regions and control zones.

20 *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).

21 117 FERC ¶ 61,220 (2006).

Table 8-2 Eligibility for ARRs vs. directly allocated FTRs

Region/Control Zone	PJM Integration Date	ARRs	Direct Allocation FTRs
Mid-Atlantic	1-Apr-99	Yes	No
AP	1-Apr-02	Yes	No
ComEd	1-May-04	Yes	No
AEP/DAY	1-Oct-04	Yes	Through 2006/2007 Planning Period
DLCO	1-Jan-05	Yes	Through 2006/2007 Planning Period
Dominion	1-May-05	Yes	Through 2006/2007 Planning Period

Table 8-3 shows that for the 2006 to 2007 planning period, 168,167 MW of annual FTR bids were cleared in the Annual FTR Auction for all control zones in the PJM footprint while 39,901 MW of annual FTR allocation requests were cleared in the annual FTR allocation for the AEP, DAY, DLCO and Dominion Control Zones.

In the direct allocation of FTRs for the AEP, DAY, DLCO and Dominion Control Zones, the total demand for annual FTR allocations was 43,796 MW for the 2006 to 2007 planning period. This is up from the 42,641 MW for the ComEd, AEP, DAY, DLCO and Dominion Control Zones in the 2005 to 2006 planning period. This includes the increase of 1,946 MW for the AEP Control Zone, the increase of 369 MW for the DAY Control Zone, the decrease of 337 MW for the DLCO Control Zone, the increase of 347 MW for the Dominion Control Zone and the decrease of 1,170 MW for the ComEd Control Zone as ComEd became ineligible for direct allocation FTRs.

Table 8-3 Annual FTR market volume: Planning period 2006 to 2007

	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume (Percent)	Uncleared Volume (MW)	Uncleared Volume (Percent)
Buy and Self-Scheduled Bids (Auction)						
All PJM Control Zones	192,358	1,608,422	168,167	10.5%	1,440,255	89.5%
Bid Requests (Direct Allocation)						
AEP	1,185	23,299	22,929	98.4%	370	1.6%
DAY	67	3,507	3,317	94.6%	190	5.4%
DLCO	22	295	186	63.1%	109	36.9%
Dominion	90	16,695	13,469	80.7%	3,226	19.3%
Total (Direct Allocation)	1,364	43,796	39,901	91.1%	3,895	8.9%
Grand Total (Auction and Direct Allocation)	193,722	1,652,218	208,068	12.6%	1,444,150	87.4%
Sell Offers (Auction)						
All PJM Control Zones	16,049	76,669	10,056	13.1%	66,613	86.9%

As Table 8-3 shows, annual FTR demand for both the auction and allocation in PJM was 1,652,218 MW during the 2006 to 2007 planning period, compared with 914,483 MW for the 2005 to 2006 planning period.

Table 8-4 shows that there were 6,331,707 MW of total demand for all bidding periods in the monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2006) of the 2006 to 2007 planning period. The monthly auctions cleared 380,147 MW (6 percent of demand) leaving 5,951,560 MW (94 percent of demand) of uncleared bids. The introduction of the monthly Balance of Planning Period FTR Auctions increased the demand for FTRs compared to the previous Monthly FTR Auctions. The Monthly FTR Auctions for the full 12-month 2005 to 2006 planning period had a total demand of 3,578,720 MW with 410,898 cleared MW (11.5 percent of demand) and 3,167,822 uncleared MW (88.5 percent of demand).

Table 8-4 Monthly balance of planning period FTR auction market volume: Planning period 2006 to 2007 through December 31, 2006

Monthly Auction	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume (Percent)	Uncleared Volume (MW)	Uncleared Volume (Percent)
Jun-06	Buy Bids	172,970	925,238	53,441	5.8%	871,797	94.2%
	Sell Offers	27,394	182,145	13,172	7.2%	168,973	92.8%
Jul-06	Buy Bids	206,527	934,424	53,102	5.7%	881,322	94.3%
	Sell Offers	33,880	214,929	21,439	10.0%	193,490	90.0%
Aug-06	Buy Bids	179,968	932,469	47,753	5.1%	884,716	94.9%
	Sell Offers	32,190	194,093	21,362	11.0%	172,731	89.0%
Sep-06	Buy Bids	183,711	841,698	52,350	6.2%	789,348	93.8%
	Sell Offers	30,671	211,625	15,000	7.1%	196,625	92.9%
Oct-06	Buy Bids	177,384	888,011	65,967	7.4%	822,044	92.6%
	Sell Offers	29,743	177,966	14,773	8.3%	163,193	91.7%
Nov-06	Buy Bids	161,447	890,318	50,626	5.7%	839,692	94.3%
	Sell Offers	21,315	125,142	10,516	8.4%	114,626	91.6%
Dec-06	Buy Bids	136,656	919,549	56,908	6.2%	862,641	93.8%
	Sell Offers	27,429	161,866	14,058	8.7%	147,808	91.3%
Total	Buy Bids	1,218,663	6,331,707	380,147	6.0%	5,951,560	94.0%
	Sell Offers	202,622	1,267,766	110,320	8.7%	1,157,446	91.3%
	Net	1,421,285	7,599,473	490,467	6.5%	7,109,006	93.5%

Market Concentration

The ownership concentration of FTR products resulting from the 2006 to 2007 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 resulted from a competitive auction. 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 FTR obligations, the Herfindahl-Hirschman Index (HHI) results were 815 for 24-hour, 998 for on-peak and 1008 for off-peak FTR products while maximum market shares were 15 percent for 24-hour, 21 percent for on-peak and 21 percent for off-peak FTR products.

For FTR options, HHIs were 6878 for 24-hour, 2016 for on-peak and 2568 for off-peak products while maximum market shares were 82 percent for 24-hour, 33 percent for on-peak and 37 percent for off-peak FTR products.

Market Performance

Volume

For the entire PJM footprint for the 2006 to 2007 planning period, 208,068 MW of annual FTRs, 168,167 MW from the Annual FTR Auction and 39,901 MW from direct allocation FTRs for new control zones, were purchased or allocated out of 1,652,218 MW bid and requested. (See Table 8-3.) For the 2006 to 2007 planning period, eligible market participants converted 38,301 MW of ARRs out of a possible 67,568 MW into annual FTRs. In comparison, during the 2005 to 2006 planning period, 180,608 MW were purchased or allocated out of 914,483 MW bid and requested. For the 2005 to 2006 planning period, eligible market participants converted 32,631 MW of ARRs into annual FTRs. Table 8-5 compares self-scheduled FTRs for the 2004 to 2005, the 2005 to 2006 and the 2006 to 2007 planning periods.

Table 8-5 Comparison of self-scheduled FTRs: Planning periods 2004 to 2005, 2005 to 2006 and 2006 to 2007

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2004/2005	13,061	33,589	38.9%
2005/2006	32,631	59,410	54.9%
2006/2007	38,301	67,568	56.7%

Price

Table 8-6 shows the cleared, weighted-average prices and volumes for annual FTR obligations and options during the 2005 to 2006 and the 2006 to 2007 planning periods. For the 2006 to 2007 planning period, weighted-average buy-bid FTR obligation prices were $1.12 per MWh with 80,680 MW cleared while weighted-average buy-bid FTR option prices were $0.29 per MWh with 49,186 MW cleared. Comparable weighted-average prices for the 2005 to 2006 planning period were $0.79 per MWh for buy-bid FTR obligations with 69,452 MW cleared and $0.21 per MWh for buy-bid FTR options with 39,096 MW cleared. For the 2006 to 2007 planning period, weighted-average sell offer FTR obligation prices were -$0.86 per MWh with 6,378 MW cleared while weighted-average sell offer FTR option prices were -$0.15 per MWh with 3,678 MW cleared. Comparable weighted-average prices for the 2005 to 2006 planning period were $0.07 per MWh for sell offer FTR obligations with 3,146 MW cleared and -$0.13 per MWh for sell offer FTR options with 1,397 MW cleared.

Table 8-6 Annual cleared average prices and volume for FTR obligations and options: Planning periods 2005 to 2006 and 2006 to 2007

Planning Period	Trade Type	Hedge Type	24-Hour ($/MWh)	24-Hour (MW)	On Peak ($/MWh)	On Peak (MW)	Off Peak ($/MWh)	Off Peak (MW)
2005/2006	Buy Bids	Obligations	$1.63	14,667	$0.45	31,426	$0.19	23,359
		Options	$0.05	3,329	$0.30	17,598	$0.19	18,169
	Self-Scheduled Bids	Obligations	$1.94	32,631	NA	NA	NA	NA
	Buy and Self-Scheduled Bids	Obligations	$1.85	47,298	$0.45	31,426	$0.19	23,359
	Sell Offers	Obligations	($0.49)	643	$0.75	1,339	($0.03)	1,164
		Options	$0.00	800	($0.52)	145	($0.46)	452
2006/2007	Buy Bids	Obligations	$1.95	13,516	$0.78	37,026	$0.78	30,138
		Options	$0.12	3,959	$0.39	24,625	$0.24	20,602
	Self-Scheduled Bids	Obligations	$2.77	38,301	NA	NA	NA	NA
	Buy and Self-Scheduled Bids	Obligations	$2.55	51,817	$0.78	37,026	$0.78	30,138
	Sell Offers	Obligations	($0.89)	2,346	$0.17	1,517	($1.34)	2,515
		Options	NA	NA	($0.16)	2,475	($0.14)	1,203

Table 8-7 shows the number, MW, weighted price and revenue for buy bids, self-scheduled bids, sell offers and net revenue for the Annual FTR Auction and monthly Balance of Planning Period FTR Auctions for the 2006 to 2007 planning period. (Table 8-3 shows both annual FTR auction data and annual FTR allocation requests.) A total of 1,608,422 MW were bid and a total of 76,669 MW were offered in the Annual FTR Auction. By comparison, for the 2005 to 2006 planning period, a total of 871,841 MW were bid and requested and a total of 63,979 MW were offered.

On average during the 2006 to 2007 planning period in the Annual FTR Auction, self-scheduled FTRs were priced $1.95 per MWh higher than buy-bid FTRs. They were also priced $0.83 per MWh higher than the cleared, weighted-average price of self-scheduled FTRs from a year ago, while Mid-Atlantic Region, AP and ComEd Control Zone buy bids were up $0.48 per MWh from the weighted-average bid price of the 2005 to 2006 planning period.

The cleared, weighted-average price paid in the monthly Balance of Planning Period FTR Auctions during the first seven months (June through December 2006) of the 2006 to 2007 planning period was $0.29 per MWh (See Table 8-9.), compared with $0.23 per MWh in the Monthly FTR Auctions for the 2005 to 2006 planning period.

Table 8-7 Annual and monthly balance of planning period FTR auction volume, price and revenue: Planning period 2006 to 2007

	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Average Bid Price ($/MWh)	Average Cleared Price ($/MWh)	Revenue
Annual Auction						
Buy Bids	186,850	1,570,121	129,866	($0.31)	$0.82	$525,228,632
Self-Scheduled Bids	5,508	38,301	38,301	NA	$2.77	$927,747,627
Buy and Self-Scheduled Bids	192,358	1,608,422	168,167	($0.30)	$1.49	$1,452,976,259
Sell Offers	16,049	76,669	10,056	($0.84)	($0.65)	($35,468,499)
Net						$1,417,507,760
Monthly Auctions*						
Buy Bids	1,218,663	6,331,707	380,147	($0.68)	$0.29	$56,668,230
Sell Offers	202,622	1,267,766	110,320	($1.26)	($0.60)	($43,064,163)
Net						$13,604,067

*Shows 7 months ending 31-Dec-06

The 2006 to 2007 planning period's price duration curve for cleared buy bids in Figure 8-1 shows that 87.2 percent of the Mid-Atlantic Region, AP and ComEd Control Zones' annual FTRs were purchased for less than $1 per MWh and 91.5 percent for less than $2 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 2006 to 2007

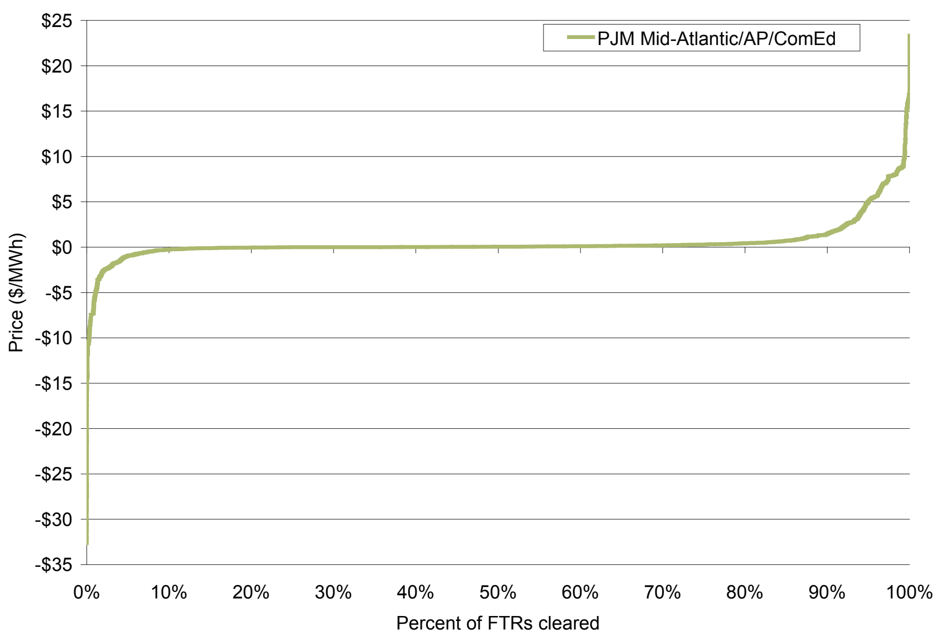


Figure 8-2 presents monthly FTR auction cleared buy-bid volume and average buy-bid clearing price. It shows that the average buy-bid clearing price dropped from 2002 to 2003 and 2004, but then rose in 2005 and dropped again in 2006. Volume steadily increased from 2002 through 2006.

Figure 8-2 Monthly FTR auction cleared buy-bid volume and average buy-bid price: Calendar years 2002 to 2006

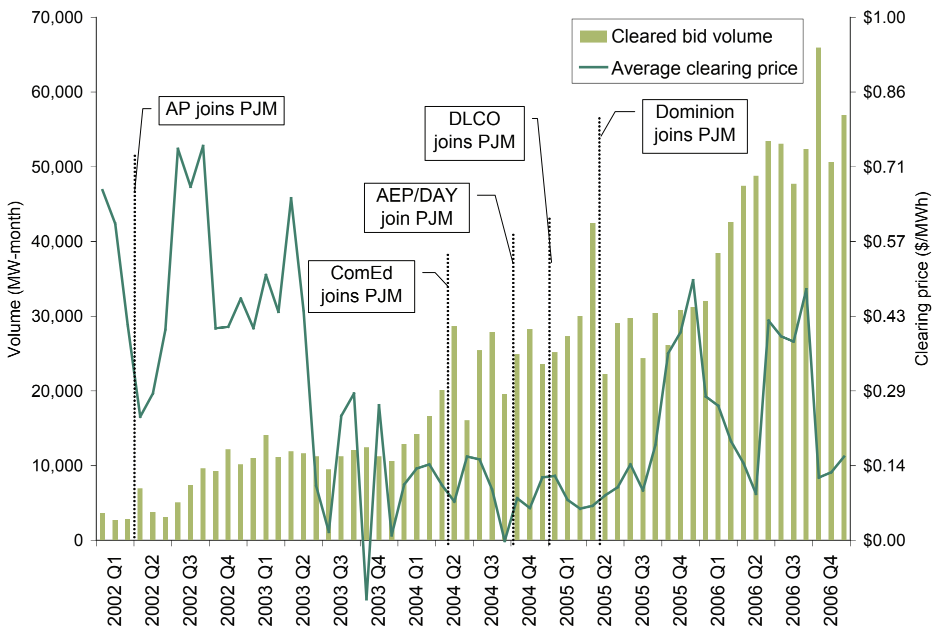


Table 8-8 and Table 8-9 show the monthly Balance of Planning Period FTR Auction results by bidding period for cleared buy-bid volume and average buy-bid price for June through December 2006. For example, for the June 2006 monthly Balance of Planning Period FTR Auction, the current month column is June, 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 the sum of all of the activity within the June 2006 monthly Balance of Planning Period FTR Auction.

Table 8-8 Monthly balance of planning period FTR auction cleared buy-bid volume (MW per period): Planning period 2006 to 2007 through December 31, 2006

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jun-06	30,936	4,258	3,882	2,067	4,077	4,138	4,083	53,441
Jul-06	36,147	6,287	1,553		2,730	3,864	2,521	53,102
Aug-06	29,416	2,678	2,680		3,780	5,077	4,122	47,753
Sep-06	36,387	4,975	3,669		1,561	2,684	3,074	52,350
Oct-06	50,305	5,916	2,550			3,225	3,971	65,967
Nov-06	37,844	3,162	2,444			2,128	5,048	50,626
Dec-06	37,031	6,350	5,654			1,929	5,944	56,908
Total	258,066	33,626	22,432	2,067	12,148	23,045	28,763	380,147

Table 8-9 Monthly balance of planning period FTR auction cleared average buy-bid price per period ($/MWh): Planning period 2006 to 2007 through December 31, 2006

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jun-06	$0.22	$0.54	$0.28	$0.05	$0.34	$1.01	$0.60	$0.42
Jul-06	$0.35	$0.66	$0.06		$0.15	$0.67	$0.21	$0.39
Aug-06	$0.50	($0.07)	($0.23)		($0.11)	$0.69	$0.38	$0.38
Sep-06	$0.21	$0.12	($0.21)		$1.75	$1.19	$0.58	$0.48
Oct-06	$0.08	$0.16	($0.04)			$0.33	$0.14	$0.12
Nov-06	$0.10	$0.12	$0.20			$0.25	$0.13	$0.13
Dec-06	($0.01)	($0.09)	($0.34)			$1.88	$0.18	$0.16
Total	$0.19	$0.23	($0.07)	$0.05	$0.35	$0.81	$0.30	$0.29

Revenue

Table 8-7 shows annual FTR auction summary data. For the 2006 to 2007 planning period, the Annual FTR Auction for the ComEd and AP Control Zones and the Mid-Atlantic Region netted $1,417.5 million in revenue, with buyers paying $1,453 million and sellers receiving $35.5 million. For the 2005 to 2006 planning period, the Mid-Atlantic Region and the AP and ComEd Control Zones' Annual FTR Auction netted $881.6 million in revenue, with buyers paying $881.7 million and sellers receiving $0.1 million.

Annual FTR Auction Revenue

Figure 8-3 summarizes total revenue associated with all FTRs, regardless of source, to the 10 FTR sinks (destinations) that produced the most annual FTR auction revenue for the 2006 to 2007 planning period. FTRs to these sinks accounted for $1,278 million or about 88 percent of all revenue paid in the Annual FTR Auction and constituted 29.4 percent of all FTRs bought in the Annual FTR Auction for the 2006 to 2007 planning period.[22]

Figure 8-3 Highest revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2006 to 2007

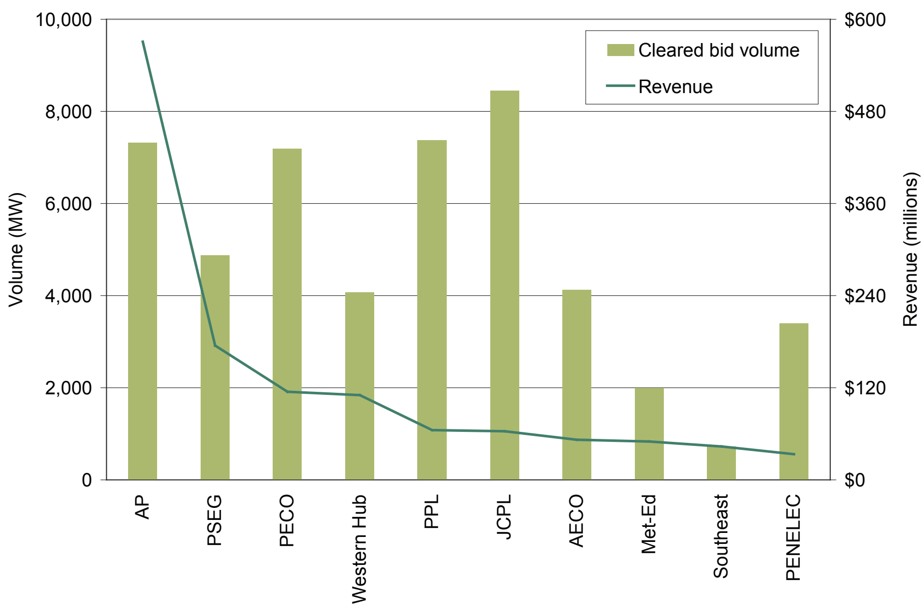


Figure 8-4 summarizes total revenue associated with all FTRs, regardless of sink, from the 10 FTR sources (origins) that produced the most annual FTR auction revenue for the 2006 to 2007 planning period. FTRs from these sources accounted for $1,056 million or about 72.7 percent of all revenue paid and included 14.4 percent of all FTRs bought in the Annual FTR Auction. These sources are generally located at large generating facilities throughout the Mid-Atlantic Region.

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

Figure 8-4 Highest revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2006 to 2007

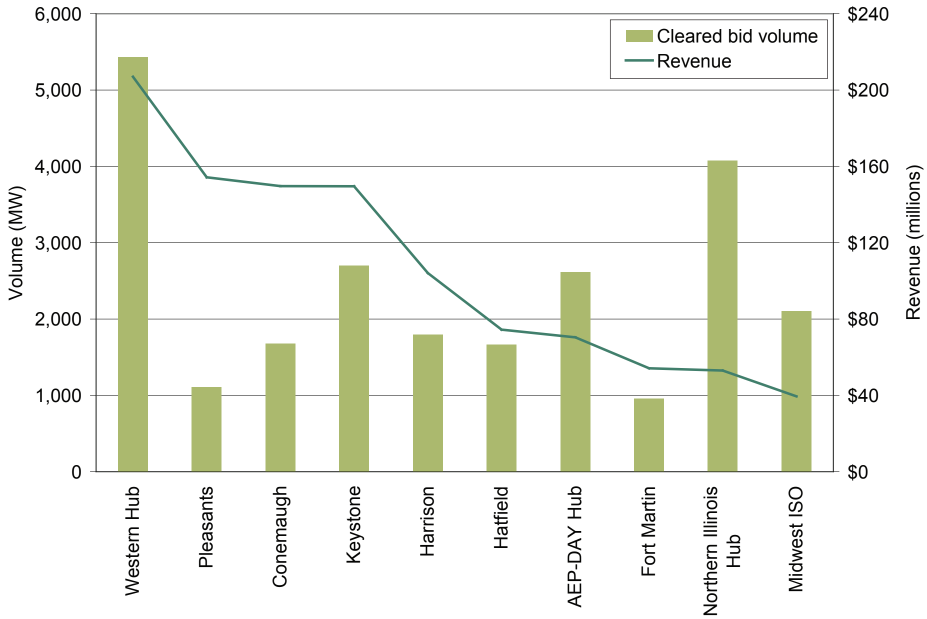


Table 8-10 shows the corresponding control zones for the FTR sinks (See Figure 8-3.) and sources (See Figure 8-4.) that produce the highest revenue in the Annual FTR Auction for the 2006 to 2007 planning period.

Table 8-10 Corresponding control zones for the highest revenue producing FTR sinks and sources in the Annual FTR Auction: Planning period 2006 to 2007[23]

FTR Sinks	FTR Sink Control Zone	FTR Sources	FTR Source Control Zone
AP	AP	Western Hub	NA
PSEG	PSEG	Pleasants	AP
PECO	PECO	Conemaugh	AP
Western Hub	NA	Keystone	AP
PPL	PPL	Harrison	AP
JCPL	JCPL	Hatfield	AP
AECO	AECO	AEP-DAY Hub	NA
Met-Ed	Met-Ed	Fort Martin	AP
Southeast	Dominion	Northern Illinois Hub	NA
PENELEC	PENELEC	Midwest ISO	External

23 FTR sink and source control zone identifications for hubs and pricing points are listed as NA because they cannot be assigned to a specific control zone.

Monthly Balance of Planning Period FTR Auction Revenue

Figure 8-5 summarizes total revenue associated with all FTRs, regardless of source, to the 10 FTR sinks that produced the most monthly balance of planning period FTR auction revenue during the first seven months of the 2006 to 2007 planning period. FTRs to these sinks accounted for $84 million and 13.5 percent of all FTRs bought in the monthly Balance of Planning Period FTR Auctions.

Figure 8-5 Highest revenue producing FTR sinks purchased in the monthly Balance of Planning Period FTR Auctions: Planning period 2006 to 2007 through December 31, 2006

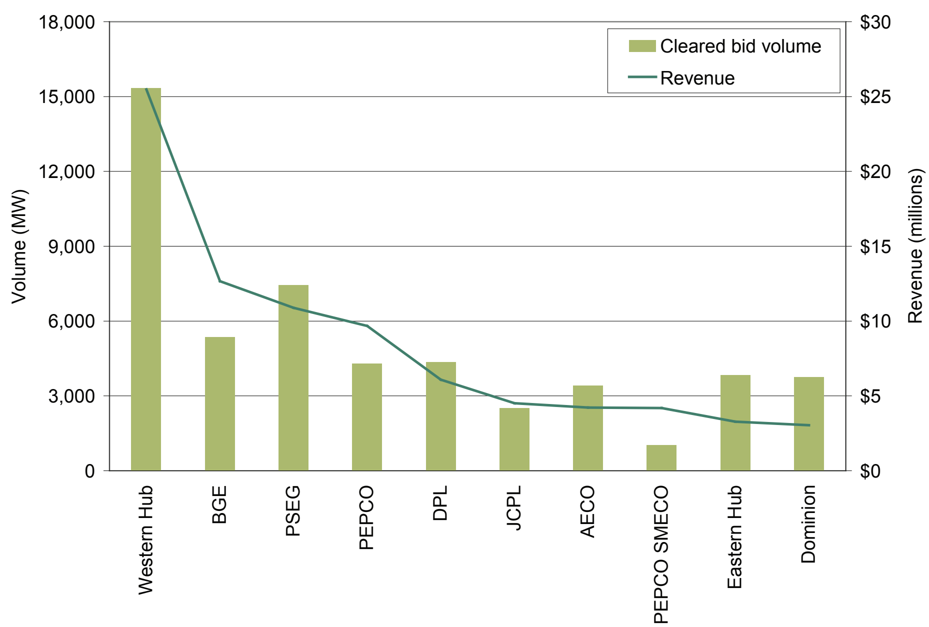


Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the 10 FTR sources that produced the most monthly balance of planning period FTR auction revenue during the first seven months of the 2006 to 2007 planning period. FTRs from these sources accounted for $110 million and 11.1 percent of all FTRs bought in monthly Balance of Planning Period FTR Auctions.

Figure 8-6 Highest revenue producing FTR sources purchased in the monthly Balance of Planning Period FTR Auctions: Planning period 2006 to 2007 through December 31, 2006

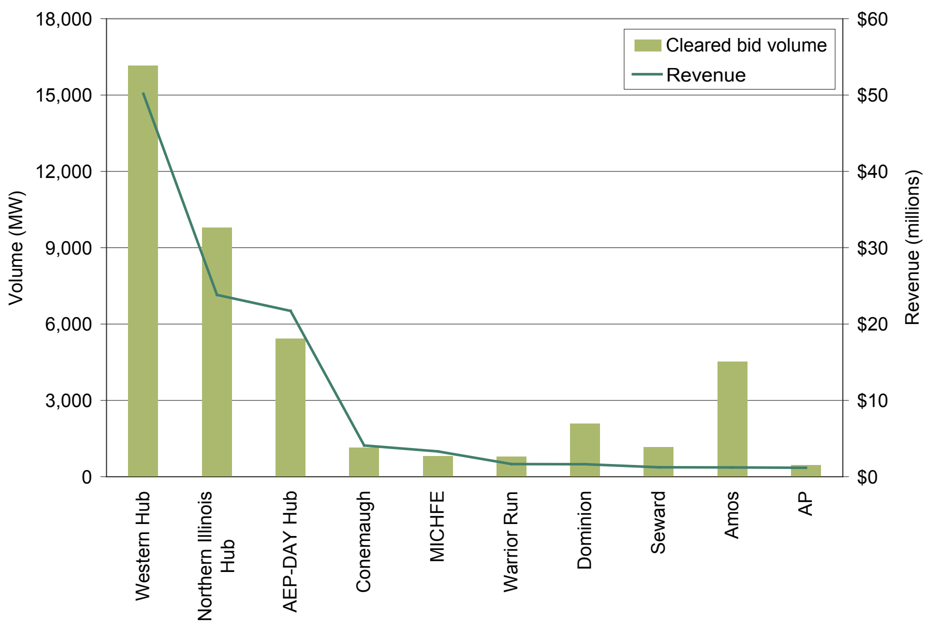


Table 8-11 shows the corresponding control zones for the FTR sinks (See Figure 8-5.) and sources (See Figure 8-6.) that produce the highest revenue in the monthly Balance of Planning Period FTR Auctions for the first seven months of the 2006 to 2007 planning period.

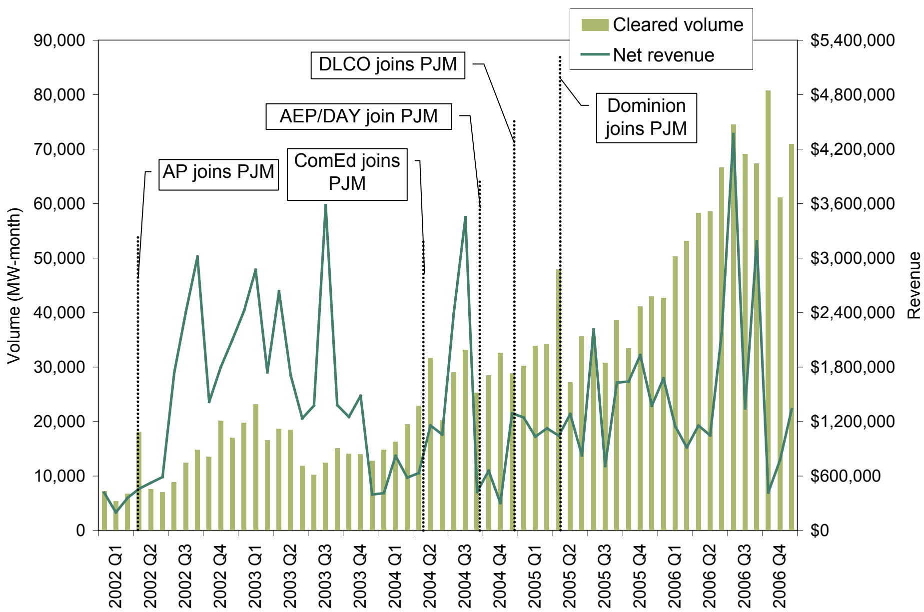
Table 8-11 Corresponding control zones for the highest revenue producing FTR sinks and sources in the monthly Balance of Planning Period FTR Auctions: Planning period 2006 to 2007 through December 31, 2006 [24]

FTR Sinks	FTR Sink Control Zone	FTR Sources	FTR Source Control Zone
Western Hub	NA	Western Hub	NA
BGE	BGE	Northern Illinois Hub	NA
PSEG	PSEG	AEP-DAY Hub	NA
PEPCO	PEPCO	Conemaugh	AP
DPL	DPL	MICHFE	NA
JCPL	JCPL	Warrior Run	AP
AECO	AECO	Dominion	Dominion
PEPCO SMECO	PEPCO	Seward	PENELEC
Eastern Hub	NA	Amos	AEP
Dominion	Dominion	AP	AP

24 FTR sink and source control zone identifications for hubs and pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-7 depicts the total cleared bid and offer volume together with the total auction revenue generated in the Monthly FTR Auctions during calendar years 2002 through 2006. Average monthly revenue for the period January 1, 2006, through December 31, 2006, was about $1.63 million per month. The average volume for the same period was 62,789 MW-month. This traded volume has significantly increased from that of calendar year 2005, which was 35,966 MW-month.

Figure 8-7 Monthly FTR auction cleared volume and net revenue: Calendar years 2002 to 2006



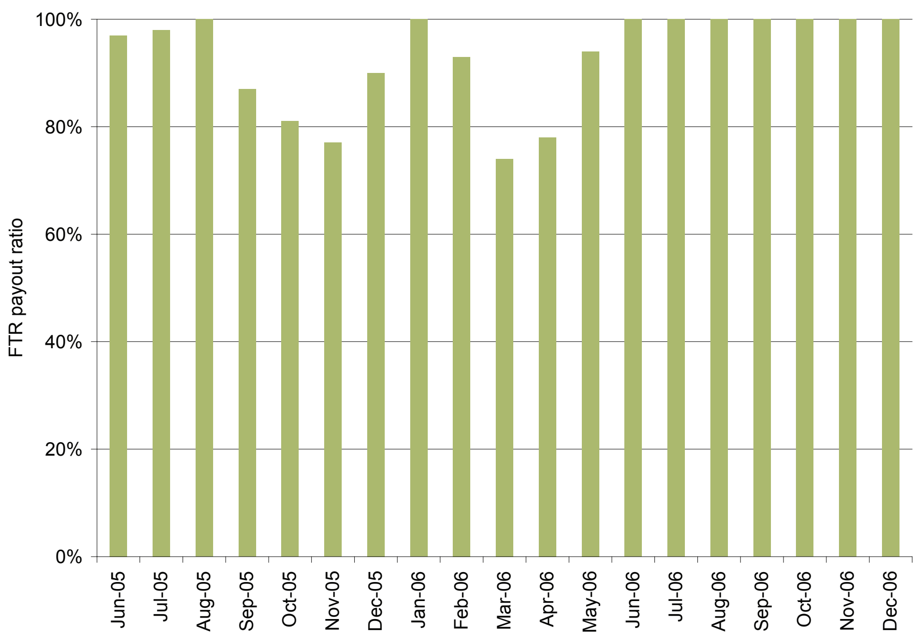
Revenue Adequacy

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, 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. An illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined is provided in Table G-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," in Appendix G, "Financial Transmission and Auction Revenue Rights." 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.

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. Figure 8-8 shows the monthly FTR payout ratio from June 2005 through December 2006.[25] FTRs were paid at 91 percent of the target allocations for the 2005 to 2006 planning period. FTRs through December 31, 2006, of the 2006 to 2007 planning period have been paid at 100 percent of the target allocation level.[26]

Figure 8-8 Monthly FTR payout ratio: June 2005 to December 2006



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 2006 to 2007 planning period through December 31, 2006. Figure 8-9 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 75.4 percent of total positive

25 See *2006 State of the Market Report*, Volume II, Section 7, "Congestion," at Table 7-5, "Monthly PJM congestion accounting summary [Dollars (millions)]: By planning period."

26 For full congestion accounting and FTR revenue adequacy data, see *2006 State of the Market Report*, Volume II, Section 7, "Congestion."

target allocations. FTRs with the top three sinks, the AP, AEP and Dominion Control Zones, included 54.4 percent of all positive target allocations. The top 10 sinks that created liability accounted for 42.2 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 10.5 percent of all negative target allocations.

Figure 8-9 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2006 to 2007 through December 31, 2006

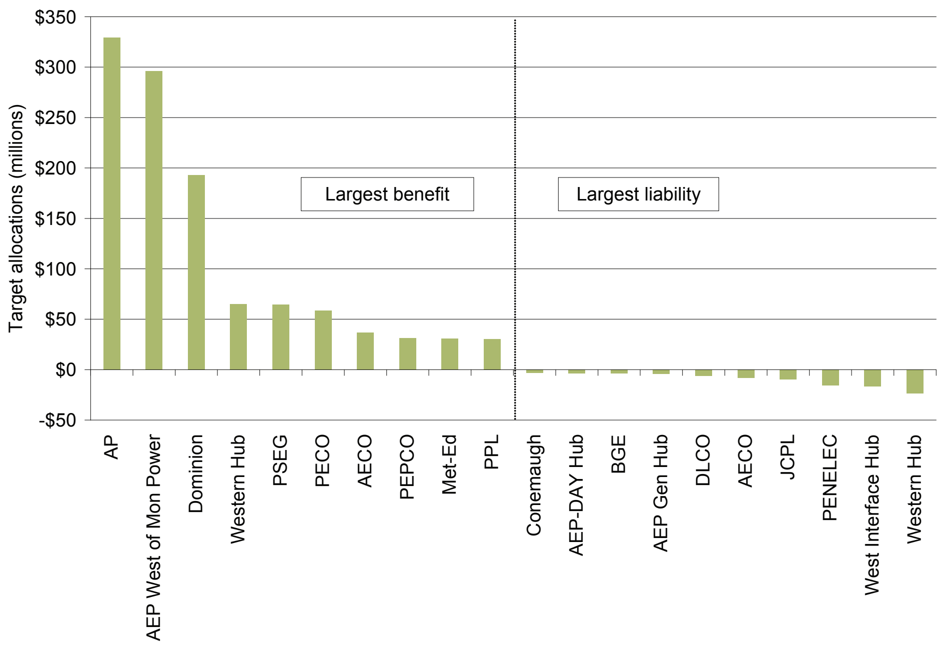
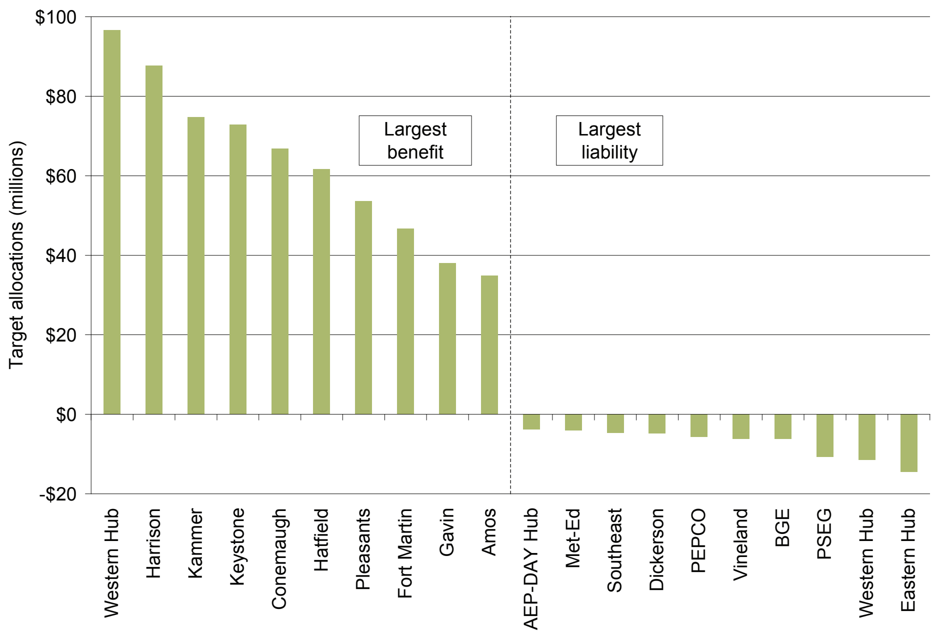


Figure 8-10 shows the FTR sources with the largest positive and negative target allocations. The top 10 sources with a positive target allocation accounted for 42.1 percent of total positive target allocations. All of these 10 sources were located in the AP and AEP Control Zones. FTRs with the Western Hub as their source included 6.4 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 32.2 percent of total negative target allocations. FTRs with the Eastern Hub as the source encompassed 6.5 percent of all negative target allocations.

Figure 8-10 Ten largest positive and negative FTR target allocations summed by source: Planning period 2006 to 2007 through December 31, 2006



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 price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or pay charges based on prices determined in the Annual FTR Auction.[27] These price differences are based on the bid prices of participants in the Annual FTR Auction. 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 price differences in the Day-Ahead Energy Market.

The ARR target allocation is equal to the product of the ARR MW and the price differences between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on these price differences, with negative differences resulting in a liability for the holder. Based on the annual and monthly balance of planning period FTR auction revenue, ARR holders are granted credits that can be positive or negative and that can range from zero to the target allocations.

ARRs have been available to eligible participants 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

27 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.

and the AP Control Zone. During the 2006 to 2007 planning period, the ComEd Control Zone was allocated ARRs. For the 2006 to 2007 planning period, the choice of ARRs or direct allocation FTRs was available to eligible market participants in the new AEP, DAY, DLCO and Dominion Control Zones. After their integration dates, market participants in the new control zones have two planning periods during which they are eligible for transitional allocation of FTRs or ARRs. After that transition, market participants are subject to the ARR allocation rules. When load shifts from one LSE to another in newly integrated control zones, directly allocated FTRs with positive economic value follow the load.[28]

In response to a 2004 order by the FERC, PJM proposed changes to its ARR allocation process that would allow certain long-term, firm point-to-point transmission service customers to participate in Stage 1 of the annual ARR allocation.[29] In a March 7, 2005, order effective the following day, the FERC approved the proposed changes in the allocation rules, allowing network and point-to-point customers to participate on the same basis in the first and second stages of ARR allocation.[30] The rules were approved before the start of the Stage 1 ARR allocation process and became effective for the 2005 to 2006 planning period and subsequent years.

For the 2006 to 2007 planning period, no mitigation credits were required for newly integrated control zones, as was required in the 2004 to 2005 planning period because long-term, firm point-to-point transmission customers can participate in the Stage 1 ARR allocation on an equal footing with network service transmission customers. Similarly, there were no mitigation credits required during the 2005 to 2006 planning period.

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 ARRs that are feasible.

ARR Allocation

Network service and long-term, firm point-to-point transmission customers can request ARRs up to the amount of their transmission service.[31] Network service customers may request ARRs up to their peak-load value, while qualifying firm transmission customers may request ARRs based on MW of firm service provided between receipt and delivery points for which the transmission customer had point-to-point transmission service during the reference year.[32, 33]

28 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 32-33.

29 106 FERC ¶ 61,049 (2004).

30 110 FERC ¶ 61,254 (2005).

31 Network service transmission customers have reliability obligations to supply load at one or more points on the system and must obtain capacity plus reserves from qualified capacity resources. Firm point-to-point transmission customers have reserved transmission capability between two points that is usually used to deliver resources into or out of the RTO. Both types of customers are referred to as eligible customers in this section.

32 Any firm transmission customers with an agreement for long-term, point-to-point transmission service that is used to deliver energy from a designated network resource to load located either outside or within the PJM Region, and that was confirmed and in effect during the historical reference year for the zone in which the resource is located.

33 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 22-26.

Each March, PJM allocates annual ARRs to eligible customers in a two-stage process, where the first stage is one round and the second stage is a four-round allocation procedure:

- **Stage 1.** In the first stage of the allocation, network service customers can obtain ARRs, up to their peak-load share, based on generation resources that historically have served load in each control zone or load aggregation zone.[34] Firm point-to-point customers can obtain ARRs based on the MW of firm, long-term 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 period covered by the allocation.

- **Stage 2.** The second stage of the allocation is a four-step procedure, with 25 percent of remaining system capability allocated in each step of the process. Network service transmission customers can obtain ARRs from any generator bus, hub, zone or interface to any part of their aggregate load in the control zone or load aggregation zone for which an ARR was not allocated in the first stage. Firm point-to-point customers can obtain ARRs consistent with their transmission service as in Stage 1.

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 powerflow model of security-constrained dispatch that takes into account generation and transmission facilities' outages and is based on reasonable assumptions about the configuration and availability of transmission capability during the planning period.[35] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all of the resulting ARR obligations, preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated pro rata 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 pro rata MW = (Constraint capability) · (Individual requested MW / Total requested MW) · (1 / per MW effect on line)[36]

Market participants constructing transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[37] 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 system simultaneous feasibility can be maintained.

34 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), p. 18.

35 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 49-50.

36 See *2006 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.

37 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 27-28.

ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can be requested through the PJM Open Access Same-Time Information System (OASIS).[38]

Prior to the start of the Stage 2 ARR allocation process, a participant can relinquish any portion of the ARR awards resulting from the Stage 1 allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[39] Participants may seek additional ARRs in the Stage 2 allocation. For the 2006 to 2007 planning period, no ARRs were relinquished after the Stage 1 ARR allocation. In comparison, eligible customers relinquished 270 MW of the allocated ARRs after the Stage 1 ARR allocation for the 2005 to 2006 planning period.

Table 8-12 lists the top 10 principal binding constraints in order of severity that limited supply in the annual ARR allocation for the 2006 to 2007 planning period. The order of severity is determined by the violation degree of the binding constraint, which is computed in the simultaneous feasibility test.[40] The violation degree is a measure of the amount of MW that a constraint is over the limit for a type of facility, where a higher number indicates a more severe constraint.

Table 8-12 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2006 to 2007[41]

Constraint	Type	Control Zone
AP South	Interface	AP
Conesville - Corridor	Line	AEP
Mount Storm - Doubs	Line	AP
East Frankfort - Goodings	Line	ComEd
Cedar Grove - Clifton	Line	PSEG
Silver Lake - Cherry Valley	Line	ComEd
East	Interface	NA
Bedington - Black Oak	Interface	AP
North East - Darbytown	Line	Dominion
Beatty - Adkins	Line	AEP

Long-Term ARRs

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 within the final rule.[42] Before the final rule, on July 3, 2006, PJM submitted to the FERC revisions to the OATT to include long-term ARRs and FTRs

38 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 19-20.

39 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 22-24.

40 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 49-50.

41 The constraint control zone identification for the East Interface is listed as NA because it cannot be assigned to a specific control zone.

42 116 FERC ¶ 61,077 (2006).

for a duration of 10 planning periods.[43] Long-term FTRs would be obtained through the self-scheduling of long-term ARRs. PJM requested an effective date of March 1, 2007, which would allow enough time for the implementation of long-term ARRs and FTRs for the 2007 to 2008 planning period. The revisions to PJM's OATT are an extension and modification to the current annual ARR allocation process. They would create a three-stage annual ARR allocation process, where 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 service customers can obtain long-term ARRs, up to their share of the zonal base load, based on generation resources that historically have served load in each control zone and up to 50 percent of their historical non-zone network load. Non-zone network load is load that is located outside of the PJM Region. Firm point-to-point customers can obtain long-term ARRs, based on up to 50 percent of the MW of firm, long-term, point-to-point service provided between the receipt and delivery points for the historical reference year. Stage 1A ARR holders can also opt out of any planning period during the 10-planning-period timeline and self-schedule their long-term ARRs as FTRs.

- **Stage 1B.** The ARRs not allocated in Stage 1A are available in the Stage 1B allocation. Network 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 non-zone network load. Firm point-to-point 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 service transmission customers can obtain ARRs from any generator bus, hub, zone or interface 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 customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

The reduction in the number of rounds from four to three for the Stage 2 allocation is to keep the total number of rounds in the annual ARR allocation process at five so as to maintain the efficiency of the annual ARR allocation process. All ARRs, including Stage 1A long-term ARRs, must be simultaneously feasible. The PJM proration method will be applied to ARRs that are not feasible. On November 22, 2006, the FERC issued an order accepting the revisions to the PJM OATT with the stipulation that they are subject to modifications.[44]

43 *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).

44 117 FERC ¶ 61,220 (2006).

Demand

ARR demand was 99,412 MW for the 2006 to 2007 planning period, up from 84,088 MW for the 2005 to 2006 planning period. Demand for ARRs increased because of load growth and the requirement for the ComEd Control Zone to select ARR allocations, instead of direct allocation FTRs.

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 OASIS. 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. Nonetheless, 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 pro rata 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 within a given control or load aggregation zone is automatically reassigned to follow that load.[45] ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same zone is allocated a proportional share of positively valued ARRs within the zone based on the shifted load. Any MW of load may be reassigned multiple times over a planning period. This rule 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.

Table 8-13 and Table 8-14 summarize ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2004 and December 2006. About 15,358 MW of ARRs associated with $307,500 per MW-day of revenue were automatically reassigned in the first seven months (June through December 2006) of the 2006 to 2007 planning period. About 18,080 MW of ARRs with $296,700 per MW-day of revenue were reassigned for the 2005 to 2006 planning period and about 22,752 MW associated with $173,600 per MW-day of revenue were reassigned for the 2004 to 2005 planning period.

45 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 26-27.

Table 8-13 ARRs automatically reassigned for network load changes by control zone (MW-day): June 1, 2004, to December 31, 2006

Control Zone	2004/2005 (12 months)	2005/2006 (12 months)	2006/2007 (7 months)*
AECO	181	530	84
AEP	94	220	38
AP	188	678	276
BGE	4,383	3,026	5,566
ComEd	3,288	4,211	4,236
DAY	48	4	3
DLCO	364	847	625
Dominion	0	74	1
DPL	2,461	2,250	928
JCPL	784	1,301	322
Met-Ed	108	120	207
PECO	830	443	70
PENELEC	73	87	118
PEPCO	8,507	2,806	2,185
PPL	219	87	17
PSEG	1,206	1,291	675
RECO	18	105	7
Total	22,752	18,080	15,358

* Through 31-Dec-06

Table 8-14 ARR revenue automatically reassigned for network load changes by control zone [Dollars (thousands) per MW-day]: June 1, 2004, to December 31, 2006

Control Zone	2004/2005 (12 months)	2005/2006 (12 months)	2006/2007 (7 months)*
AECO	$4.3	$17.4	$3.5
AEP	$0.0	$5.0	$1.0
AP	$0.0	$75.2	$57.0
BGE	$41.7	$45.1	$136.3
ComEd	$0.1	$12.3	$4.5
DAY	$0.0	$0.0	$0.0
DLCO	$0.0	$8.2	$2.0
Dominion	$0.0	$0.0	$0.0
DPL	$34.5	$29.8	$12.8
JCPL	$10.9	$23.6	$7.4
Met-Ed	$1.3	$3.2	$10.1
PECO	$15.3	$16.3	$2.7
PENELEC	$2.0	$1.9	$5.7
PEPCO	$29.2	$20.5	$41.3
PPL	$2.0	$1.8	$0.7
PSEG	$32.3	$35.8	$22.5
RECO	$0.0	$0.6	$0.0
Total	$173.6	$296.7	$307.5
* Through 31-Dec-06			

Market Performance

Volume

Table 8-15 lists the annual ARR allocation volume for the 2004 to 2005, the 2005 to 2006 and the 2006 to 2007 planning periods. For the 2006 to 2007 planning period, there were 56,705 MW (57 percent of demand) bid in Stage 1 and 42,707 MW (43 percent of 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. Eligible market participants subsequently converted 38,301 MW of these allocated ARRs into annual FTRs (56.7 percent of total allocated ARRs), leaving 29,267 MW of ARRs outstanding. For the 2005 to 2006 planning period, there had been 50,955 MW (60.6 percent of demand) bid in Stage 1 and 33,133 MW (39.4 percent of demand) bid in Stage 2. Of 84,088 MW in total ARR requests for the 2005 to 2006 planning period, 49,577 MW were allocated in Stage 1 while 9,833 MW were allocated in Stage 2 for a total of 59,410 MW (70.7 percent) allocated. There were 32,631 MW or 54.9 percent of the allocated ARRs converted into FTRs.

Table 8-15 Annual ARR allocation volume: Planning periods 2004 to 2005, 2005 to 2006 and 2006 to 2007

Planning Period	Stage	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume (Percent)	Uncleared Volume (MW)	Uncleared Volume (Percent)
2004/2005	1	3,582	22,576	21,820	96.7%	756	3.3%
	2	3,296	32,552	11,769	36.2%	20,783	63.8%
	Total	6,878	55,128	33,589	60.9%	21,539	39.1%
2005/2006	1	6,348	50,955	49,577	97.3%	1,378	2.7%
	2	3,462	33,133	9,833	29.7%	23,300	70.3%
	Total	9,810	84,088	59,410	70.7%	24,678	29.3%
2006/2007	1	7,294	56,705	54,430	96.0%	2,275	4.0%
	2	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%

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.

An ARR target allocation defines revenue that an ARR holder should receive and is equal to the product of the ARR MW and the price difference between ARR sink and source established during the Annual FTR Auction. FTR auction revenue is the net revenue from the auction. The prices that result from the Annual FTR Auction are the result of bids based on participants' expectations about the level of congestion in the Day-Ahead Energy Market. All ARR holders receive ARR credits equal to their target allocations if total net annual and monthly balance of planning period FTR auction revenues are greater than, or equal to, the sum of all ARR target allocations. If the combined net annual and monthly balance of planning period FTR auction revenues are less than that, the available revenue is proportionally allocated among all ARR holders.

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 $1,405 million in credits from the Annual FTR Auction during the 2006 to 2007 planning period, with an average hourly ARR credit of $2.37 per MWh. During the comparable 2005 to 2006 planning period, ARR holders received $870 million in ARR credits, with an average hourly ARR credit of $1.67 per MWh.

Table 8-16 lists ARR target allocations and net revenue sources from the Annual and Monthly FTR Auctions for the 2004 to 2005, the 2005 to 2006 and the 2006 to 2007 (through December 31, 2006) planning periods. Annual FTR auction net revenue has been sufficient to cover ARR target allocations for all three planning periods. The 2006 to 2007 planning period's Annual and monthly Balance of Planning Period FTR Auctions generated a surplus of $27 million in auction net revenue through December 31, 2006, above the amount needed to pay 100 percent of ARR target allocations. The whole 2005 to 2006 planning period's Annual and Monthly FTR Auctions generated a surplus of $28 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-16 ARR revenue adequacy [Dollars (millions)]: Planning periods 2004 to 2005, 2005 to 2006 and 2006 to 2007

	2004/2005	2005/2006	2006/2007
Total FTR Auction Net Revenue	$385	$898	$1,432
Annual FTR Auction Net Revenue	$370	$882	$1,418
Monthly FTR Auction Net Revenue*	$15	$16	$14
ARR Target Allocations	$345	$870	$1,405
ARR Credits	$345	$870	$1,405
Surplus Auction Revenue	$40	$28	$27
ARR Payout Ratio	100%	100%	100%

* Shows 12 months for 2004/2005 and 2005/2006, and 7 months ending 31-Dec-06 for 2006/2007

ARR Proration Issues

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.[46, 47]

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

46 PJM "Manual 6: Financial Transmission Rights," Revision 8 (March 8, 2006), pp. 25-26.

47 See *2006 State of the Market Report*, Volume II, Appendix G, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining the ARR prorating method.

flow on the binding constraint. The PJM method prorates those ARR requests that have the greatest impact on the binding constraint rather than prorating a greater number of requests with 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 rather than those that produce less flow on the binding constraint. 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.

When ARRs were allocated for the 2006 to 2007 planning period, some of the requested ARRs were prorated in order to ensure simultaneous feasibility. For the 2006 to 2007 planning period, one of the major constraints limiting the allocation of ARRs was the Bedington-Black Oak Interface. In all, over 2,500 MW of Stage 1 ARR requests, with approximately 700 MW of these attributable to the Bedington–Black Oak Interface, were denied based on the application of PJM's proration method.

A number of factors caused the proration of requested ARRs associated with the binding Bedington–Black Oak Interface transmission limitation. They include an increase in ARR requests for congested paths on the Bedington–Black Oak Interface, general load growth and increased unscheduled transmission flow across the PJM system from external sources.

On August 1, 2006, two municipalities, the Borough of Chambersburg, Pennsylvania, and the Town of Front Royal, Virginia, filed a complaint with the FERC regarding the proration of their requested ARRs.[48] PJM filed an answer to the complaint on August 23, 2006.[49] In a November 22, 2006, order, the FERC denied the complaint and found that PJM had correctly applied the rules within its OATT and that it would not be appropriate to rerun the annual ARR allocation process for the 2006 to 2007 planning period because parties had already made commitments based on those ARR allocations.[50] On, December 21, 2006, the Borough of Chambersburg, Pennsylvania, and the Town of Front Royal, Virginia, submitted to the FERC a request for a rehearing of their complaints.[51]

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-11 shows annual FTR auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone based on the difference between zonal prices and Western Hub prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $6.89 per MWh in the Annual FTR Auction and that about $3.04 per MWh of day-ahead congestion and $1.87 per MWh of real-time congestion existed between the Western Hub and the control zone. The data show that congestion costs, approximated

48 *Front Royal, Town of,* Complaint of the Borough of Chambersburg, PA, and the Town of Front Royal, VA, against PJM Interconnection, L.L.C., Docket No. EL06-94-000 (August 1, 2006).

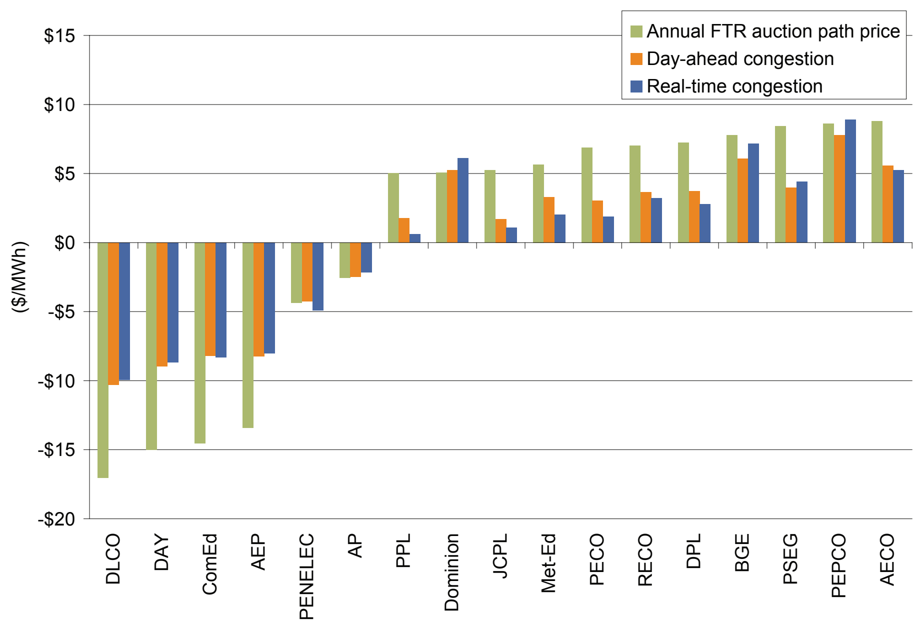
49 *Front Royal, Town of,* Answer of PJM Interconnection, L.L.C. to complaint, Docket No. EL06-94-000 (August 23, 2006).

50 117 FERC ¶ 61,219 (2006).

51 *Front Royal, Town of,* Request for Rehearing of the Borough of Chambersburg, PA, and the Town of Front Royal, VA, Docket No. EL06-94-000 (December 21, 2006).

in this way, were positive and were lower than the positive price of FTRs for most control zones that are located east of the Western Hub while congestion costs were negative and were less negative than the negative price of FTRs for control zones that are located west of that hub.

Figure 8-11 Annual FTR auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2006 to 2007 through December 31, 2006



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 and Balancing Energy Market. Thus, ARRs are an indirect hedge against actual congestion in both the Day-Ahead and 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 and Balancing Energy Market is presented by control zone in Table 8-17. ARRs and self-scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[52] 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

52 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.

back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (does not include any self-scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the 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 91 percent of the target allocation for the 2005 to 2006 planning period.

The "Congestion" column shows the amount of congestion in each control zone from the Day-Ahead and 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 2005 to 2006 planning period summed by ARR control zone sink. For example, the table shows that for the 2005 to 2006 planning period, ARRs allocated to the PSEG Control Zone received a total of $99.2 million in revenue which was the sum of $91.3 million in ARR credits and $7.9 million in credits for self-scheduled FTRs. This total revenue was $107.5 million less than the congestion costs of $206.7 million from the Day-Ahead and Balancing Energy Market incurred by organizations in the PSEG Control Zone that held ARRs or self-scheduled FTRs.

Table 8-17 ARR and self-scheduled FTR congestion hedging by control zone: Planning period 2005 to 2006

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference
AECO	$25,080,775	$7,555,906	$32,636,681	$139,421,972	($106,785,291)
AEP	$6,693,203	$0	$6,693,203	$448,522,559	($441,829,356)
AP	$33,933,744	$605,976,607	$639,910,351	$391,081,639	$248,828,712
BGE	$28,664,369	$15,833,167	$44,497,536	$99,551,176	($55,053,640)
ComEd	$14,507,397	($2,216,615)	$12,290,782	($40,725,173)	$53,015,955
DAY	$513,680	($906,367)	($392,687)	$31,002,175	($31,394,862)
DLCO	$4,928,691	$0	$4,928,691	($17,577,325)	$22,506,016
Dominion	$14,167,230	$1,991,239	$16,158,469	($3,726,484)	$19,884,953
DPL	$18,340,277	$2,740,951	$21,081,228	$169,195,102	($148,113,874)
JCPL	$22,708,342	$13,228,703	$35,937,045	$187,860,938	($151,923,893)
Met-Ed	$833,842	$38,521,619	$39,355,461	$96,411,629	($57,056,168)
PECO	$25,077,047	$83,967,680	$109,044,727	($30,485,404)	$139,530,131
PENELEC	$7,362,595	$20,554,603	$27,917,198	$133,872,573	($105,955,375)
PEPCO	$15,702,093	$9,208,222	$24,910,315	$421,462,182	($396,551,867)
PJM	$0	$599,826	$599,826	$53,153,698	($52,553,872)
PPL	$3,760,574	$50,948,653	$54,709,227	($61,590,973)	$116,300,200
PSEG	$91,334,187	$7,868,690	$99,202,877	$206,732,139	($107,529,262)
RECO	$1,103,171	$53,438	$1,156,609	$14,168,651	($13,012,042)
Total	$314,711,217	$855,926,322	$1,170,637,539	$2,238,331,074	($1,067,693,535)

During the 2005 to 2006 planning period, congestion costs associated with the 59,410 MW of allocated ARRs were $2,238.3 million. As Table 8-5 indicates, 32,631 MW of ARRs were converted into FTRs through the self-scheduling option, with 26,779 MW remaining as ARRs. The 26,779 MW of remaining ARRs provided $314.7 million of ARR credits, representing a hedge of 14.1 percent of the $2,238.3 million in congestion costs incurred, while the self-scheduled FTRs provided $855.9 million of revenue, hedging an additional 38.2 percent of congestion costs. Total congestion hedged by both was $1,170.6 million, or 52.3 percent. (See Table 8-17.) 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 Market and on the FTR payout ratio.

Effectiveness of FTRs as a Hedge against Congestion

FTRs provide a direct hedge against congestion costs. Table 8-18 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 2005 to 2006 planning period. FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable.[53] 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 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 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 91 percent of the target allocation for the 2005 to 2006 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 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 and 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 $1,312.6 million against $2,203.9 million in congestion costs incurred.[54] This demonstrates that all FTRs provided a 59.6 percent hedge against congestion costs in PJM. For example, the table shows that for the 2005 to 2006 planning period, all FTRs sunk in the AP Control Zone received a total of $556 million in FTR credits while these FTRs cost $286.9 million in the FTR auctions. This gives a total FTR hedge of $269.1 million against $483.6 million in congestion costs from the Day-Ahead and Balancing Energy Market. This shows a deficit of $214.5 million in their total FTR hedge position versus the cost of congestion in the Day-Ahead and 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 8-19.

53 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.

54 The congestion costs in Table 8-18 do not equal the congestion costs in Table 8-17 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 8-18 FTR congestion hedging by control zone: Planning period 2005 to 2006

Control Zone	FTR Credits	FTR Auction Revenue	FTR Hedge	Congestion	FTR Hedge - Congestion Difference
AECO	$45,920,643	$42,074,184	$3,846,459	$85,668,131	($81,821,672)
AEP	$441,211,478	($15,723,909)	$456,935,387	$280,012,369	$176,923,018
AP	$555,983,348	$286,893,310	$269,090,038	$483,593,991	($214,503,953)
BGE	$99,105,743	$38,738,484	$60,367,259	$120,054,110	($59,686,851)
ComEd	($1,114,514)	$6,699,398	($7,813,912)	$211,614,849	($219,428,761)
DAY	($4,941,077)	($1,360,475)	($3,580,602)	$17,881,685	($21,462,287)
DLCO	($8,712,557)	($2,058,290)	($6,654,267)	$43,665,845	($50,320,112)
Dominion	$303,302,735	$2,301,529	$301,001,206	$235,274,973	$65,726,233
DPL	$31,778,673	$68,793,242	($37,014,569)	$122,049,540	($159,064,109)
JCPL	$45,242,267	$51,158,477	($5,916,210)	$157,969,491	($163,885,701)
Met-Ed	$67,782,208	$40,371,152	$27,411,056	$27,068,919	$342,137
PECO	$115,947,529	$118,291,396	($2,343,867)	($68,894,565)	$66,550,698
PENELEC	$32,497,904	$3,022,325	$29,475,579	$132,652,047	($103,176,468)
PEPCO	$233,047,816	$69,380,488	$163,667,328	$232,932,481	($69,265,153)
PJM	$23,394,836	$1,702,640	$21,692,196	($1,896,592)	$23,588,788
PPL	$58,023,715	$50,806,886	$7,216,829	($76,131,684)	$83,348,513
PSEG	$169,053,611	$133,431,947	$35,621,664	$182,384,671	($146,763,007)
RECO	$2,949,755	$3,392,076	($442,321)	$17,996,930	($18,439,251)
Total	$2,210,474,113	$897,914,860	$1,312,559,253	$2,203,897,191	($891,337,938)

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-19 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead and Balancing Energy Market for the 2005 to 2006 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.[55] 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 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 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 91 percent of the target allocation for the 2005 to 2006 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 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

55 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.

revenue. The “Congestion” column shows the total amount of congestion in the Day-Ahead and 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 $21 million, or slightly less than one percent. During the 2005 to 2006 planning period, the 59,410 MW of cleared ARRs produced $870.3 million of ARR credits while the total of all FTR credits was $2,210.5 million. Together, the ARR credits and FTR credits provided $3,080.8 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 $897.9 million for the 2005 to 2006 planning period. The total ARR and FTR hedge equals $2,182.9 million, a hedge of 99 percent of $2,203.9 million of congestion in the Day-Ahead and Balancing Energy Market.[56] For example, the table shows that all ARRs and FTRs that sink in the PPL Control Zone received $55.4 million in ARR credits and $58 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $50.8 million, the total ARR and FTR hedge was $62.6 million. Their total hedge was $138.7 million higher than the -$76.1 million of congestion in the Day-Ahead and Balancing Energy Market.

Table 8-19 ARR and FTR congestion hedging by control zone: Planning period 2005 to 2006

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference
AECO	$31,276,088	$45,920,643	$42,074,184	$35,122,547	$85,668,131	($50,545,584)
AEP	$16,585,860	$441,211,478	($15,723,909)	$473,521,247	$280,012,369	$193,508,878
AP	$361,469,998	$555,983,348	$286,893,310	$630,560,036	$483,593,991	$146,966,045
BGE	$34,661,561	$99,105,743	$38,738,484	$95,028,820	$120,054,110	($25,025,290)
ComEd	$18,303,358	($1,114,514)	$6,699,398	$10,489,446	$211,614,849	($201,125,403)
DAY	$530,510	($4,941,077)	($1,360,475)	($3,050,092)	$17,881,685	($20,931,777)
DLCO	$4,975,801	($8,712,557)	($2,058,290)	($1,678,466)	$43,665,845	($45,344,311)
Dominion	$15,272,576	$303,302,735	$2,301,529	$316,273,782	$235,274,973	$80,998,809
DPL	$21,623,521	$31,778,673	$68,793,242	($15,391,048)	$122,049,540	($137,440,588)
JCPL	$37,324,433	$45,242,267	$51,158,477	$31,408,223	$157,969,491	($126,561,268)
Met-Ed	$26,625,842	$67,782,208	$40,371,152	$54,036,898	$27,068,919	$26,967,979
PECO	$106,838,594	$115,947,529	$118,291,396	$104,494,727	($68,894,565)	$173,389,292
PENELEC	$20,595,178	$32,497,904	$3,022,325	$50,070,757	$132,652,047	($82,581,290)
PEPCO	$18,332,199	$233,047,816	$69,380,488	$181,999,527	$232,932,481	($50,932,954)
PJM	$2,106,635	$23,394,836	$1,702,640	$23,798,831	($1,896,592)	$25,695,423
PPL	$55,370,821	$58,023,715	$50,806,886	$62,587,650	($76,131,684)	$138,719,334
PSEG	$97,257,083	$169,053,611	$133,431,947	$132,878,747	$182,384,671	($49,505,924)
RECO	$1,163,157	$2,949,755	$3,392,076	$720,836	$17,996,930	($17,276,094)
Total	$870,313,215	$2,210,474,113	$897,914,860	$2,182,872,468	$2,203,897,191	($21,024,723)

56 The congestion costs in Table 8-19 do not equal the congestion costs in Table 8-17 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 shows that for the 2005 to 2006 planning period, the total ARR and FTR hedge was $21 million less than the total congestion within PJM. All ARRs and FTRs hedged approximately 99 percent of the total congestion costs in the Day-Ahead and Balancing Energy Market within PJM.[57] For the first seven months (June through December 2006) of the 2006 to 2007 planning period, all ARRs and FTRs hedged 98.4 percent of the total congestion costs within PJM. The total ARR and FTR hedge position was less than the cost of congestion by $16.8 million.

Table 8-20 ARR and FTR congestion hedging: Planning periods 2005 to 2006 and 2006 to 2007[58]

Planning Period	ARR Credits	FTR Payout Ratio	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference
2005/2006	$870,313,215	91%	$2,210,474,113	$897,914,860	$2,182,872,468	$2,203,897,191	($21,024,723)
2006/2007*	$1,404,646,982	100%	$1,087,193,025	$1,431,111,828	$1,060,728,179	$1,077,545,881	($16,817,702)
* Shows 7 months ending 31-Dec-06							

57 The congestion costs for the 2005 to 2006 planning period in Table 8-20 do not equal the congestion costs in Table 8-17 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.

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