SECTION 8 – FINANCIAL TRANSMISSION AND AUCTION REVENUE RIGHTS

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

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

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

The *2010 State of the Market Report for PJM* focuses on the annual ARR allocations, the Annual FTR Auctions and the Monthly Balance of Planning Period FTR Auctions during two FTR/ARR planning periods: the 2009 to 2010 planning period which covers June 1, 2009, through May 31, 2010, and the 2010 to 2011 planning period which covers June 1, 2010, through May 31, 2011. The *2010 State of the Market Report for PJM* also analyzes the results of the 2011 to 2014 Long Term FTR Auction that covers three consecutive planning periods: June 1, 2011 through May 31, 2012, June 1, 2012 through May 31, 2013 and June 1, 2013 through May 31, 2014.

Table 8-1 The FTR Auction Markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Competitive	
Market Performance	**Competitive**	**Effective**

1 87 FERC ¶ 61,054 (1999).

- The market structure was evaluated as competitive because the FTR auction is voluntary and the ownership positions resulted from the distribution of ARRs and voluntary participation.
- Participant behavior was evaluated as competitive because there was no evidence of anti competitive behavior in 2010 and there is no limit on FTR demand in any FTR auction.
- Performance was evaluated as competitive because it reflected the interaction between participant behavior and FTR supply limited by PJM's analysis of system feasibility.
- Market design was evaluated as effective because the market design provides a wide range of options for market participants to acquire FTRs and a competitive auction mechanism.

Highlights and New Analysis

- FTRs were paid at 96.9 percent of the target allocation level for the 2009 to 2010 planning period and were paid at 85.2 percent of the target allocation level for the 2010 to 2011 planning period through December 31, 2010.
- The net revenue from the 2011 to 2014 Long Term FTR Auction increased 60 percent ($18.7 million) from the 2010 to 2013 Long Term FTR Auction. In contrast, the net revenue from the 2010 to 2011 Annual FTR Auction decreased 21 percent ($280 million) from the 2009 to 2010 Annual FTR Auction.
- The percent of ARRs self-scheduled as FTRs in the Annual FTR Auction decreased by 8 percent from the 2009 to 2010 planning period, to the 2010 to 2011 planning period.
- The total secondary bilateral FTR obligation market volume increased from 8,810 MW in the 2009 to 2010 planning period to 24,034 MW in the first seven months of the 2010 to 2011 planning period.
- The buy bid prices for 24 hour counter flow FTRs were negative and greater in magnitude than the buy bid prices for prevailing flow FTRs in the 2011 to 2014 Long Term Auction with the result that the total weighted-average cleared price for all 24 hour buy bid FTRs was negative (-$0.16). The weighted-average cleared price for all 24 hour buy bid FTRs in the 2010 to 2013 Long Term Auction was $0.53.
- No ARRs were prorated in Stage 1A and Stage 1B for the 2010 to 2011 planning period.
- FTRs were profitable overall and were profitable for both physical entities and financial entities in 2010. Total FTR profits in 2010 were $909.6 million for physical entities and $138.7 million for financial entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities.
- On July 23, 2010, PJM reported that it had settled litigation brought against the Tower Companies arising from the default of their affiliate Power Edge, LLC in 2007, in Federal Court

and at the FERC.[2] The FERC's investigation of whether manipulation of the FTR markets occurred continues.[3]

Recommendations

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

- The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do.

- The MMU recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding.

Overview

Financial Transmission Rights

Market Structure

- **Supply.** PJM operates an Annual FTR Auction for all control zones in the PJM footprint. PJM conducts Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period, to allow participants to buy and sell any residual transmission capability. PJM also runs a Long Term FTR Auction for the three consecutive planning years immediately following the planning year during which the Long Term FTR Auction is conducted. The first Long Term FTR Auction was conducted during the 2008 to 2009 planning period and covers three consecutive planning periods between 2009 and 2012. The most recent Long Term FTR Auction was conducted during the 2010 to 2011 planning period and covers three consecutive planning periods between 2011 and 2014. In addition, PJM administers a secondary bilateral market to allow participants to buy and sell existing FTRs. FTR products include FTR obligations and FTR options. FTR options are not available in the Long Term FTR Auction. For each time period, there are three FTR products: 24-hour, on peak and off peak. FTRs have terms varying from one month to three years. FTR supply is limited by the capability of the transmission system to accommodate simultaneously the set of requested FTRs and the numerous combinations of FTRs. The principal binding constraints limiting the supply of FTRs in the 2011 to 2014 Long Term FTR Auction include the Millville – Old Chapel Line and the Lovettsville – Millville Line. The principal binding constraints limiting the supply of FTRs in the Annual FTR Auction for the 2010 to 2011 planning period include the Doubs Transformer and the Messick Road - Ridgeley

2 See FERC Docket No. EL08-44-000 and the Federal Court proceedings in United States District Counts in Delaware and Pennsylvania, DE No. 08-216-JJF and Eastern Dist PA, C.A. No. 08-CV-3649-NS.

3 See 127 FERC ¶ 61,007 at PP 2&5 (2009).

line. Market participants can also sell FTRs. In the 2011 to 2014 Long Term FTR Auction, total FTR sell offers were 177,540 MW, up from 51,582 MW during the 2010 to 2013 Long Term FTR Auction. In the Annual FTR Auction for the 2010 to 2011 planning period, total FTR sell offers were 178,428. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2010) of the 2010 to 2011 planning period, there were 2,766,728 MW of FTR sell offers.

- **Demand.** There is no limit on FTR demand in any FTR auction. In the 2011 to 2014 Long Term FTR Auction, total FTR buy bids were 1,996,084 MW. In the Annual FTR Auction for the 2010 to 2011 planning period, total FTR buy bids were 1,708,556 MW, up from 1,436,335 MW during the 2009 to 2010 planning period. Total FTR self scheduled bids were 55,732 MW for the 2010 to 2011 planning period, a decrease from 68,589 MW for the 2009 to 2010 planning period. In the Monthly Balance of Planning Period FTR Auctions for the first seven months (June through December 2010) of the 2010 to 2011 planning period, total FTR buy bids were 8,973,645 MW.

- **FTR Credit Issues.** There were no participant defaults in 2010. The MMU continues to recommend the complete elimination of unsecured credit from PJM markets, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members.

- **Tower Companies Litigation and Investigation.** On July 23, 2010, PJM reported that it had settled litigation brought against the Tower Companies arising from the default of their affiliate Power Edge, LLC in 2007, in Federal Court and at the FERC.[4] This matter concerned in part allegations that the Tower Companies "manipulated PJM's Day-ahead energy and Financial Transmission Rights (FTR) markets."[5] The FERC also commenced its own independent investigation.[6] The Market Monitor had been scheduled to testify in the Court proceeding as a fact witness and as a non-retained or employed expert witness on the basis of the MMU's extensive non-public analysis. Under the terms of the settlement, the Tower Companies paid $18 million in return for PJM withdrawing its civil complaint and the remainder of its complaint at the FERC related to this matter. In September 2010, the PJM Members Committee adopted and then implemented the following resolution: "The PJM Members Committee resolves to request the chair of the Members Committee to send a letter to FERC Office of Enforcement to request expeditious conclusion of the investigation of Tower affiliates in the matter of alleged improper use of virtual trades and make public the results of that investigation consistent with FERC practices and procedures."[7]

- **Patterns of Ownership.** The ownership concentration of cleared FTR buy bids resulting from the 2010 to 2011 Annual FTR Auction was low to moderate for FTR obligations and moderate to high for FTR options. The level of concentration is only descriptive and is not a measure of the competitiveness of FTR market structure as the ownership positions resulted from a competitive auction. In order to provide additional information about the ownership of prevailing flow and counter flow FTRs, the Market Monitoring Unit (MMU) categorized all participants owning FTRs

4 See FERC Docket No. EL08-44-000 and the Federal Court proceedings in United States District Counts in Delaware and Pennsylvania, DE No. 08-216-JJF and Eastern Dist PA, C.A. No. 08-CV-3649-NS.
5 See 127 FERC ¶ 61,007 at P 1 (2009).
6 *Id.*
7 See letter from Edward D. Tatum, Chair, PJM Members Committee, to Norman Bay, Director, Office of Enforcement (FERC) dated September 27, 2010, which can be accessed at <http://www.pjm.com/~/media/committees-groups/committees/mc/20100923/20100923-item-05-mc-chair-letter-to-ferc-oe.ashx>.

in PJM as either physical or financial. Physical entities include utilities and customers which primarily take physical positions in PJM markets. Financial entities include banks and hedge funds which primarily take financial positions in PJM markets. During the 2010 to 2011 planning period, physical entities own 54 percent of prevailing flow Annual cleared buy bid FTRs while financial entities own 72 percent of counter flow Annual cleared buy bid FTRs. Overall, financial entities own 53 percent of all FTRs bought in the Annual Auction. Financial entities own 84 percent of FTRs bought and sold in the Long Term FTR Auction. Financial entities own 77 percent of prevailing flow and 88 percent of counter flow FTRs bought in the Monthly Balance of Planning Period Auctions. Overall, financial entities own 82 percent of all Monthly Balance of Planning Period cleared buy bid FTRs. Physical entities owned 49 percent of all FTRs in 2010. Financial entities owned 68 percent of all counter flow FTRs and 46 percent of all prevailing flow FTRs in 2010.

Market Performance

- **Volume.** The 2011 to 2014 Long Term FTR Auction cleared 238,681 MW (12.0 percent of demand) of FTR buy bids, up from 86,108 MW (8.1 percent) in the 2010 to 2013 Long Term FTR Auction. The 2011 to 2014 Long Term FTR Auction also cleared 12,501 MW (7.0 percent) of FTR sell offers, up from 5,147 MW (10.0 percent) in the 2010 to 2013 Long Term FTR Auction. For the 2010 to 2011 planning period, the Annual FTR Auction cleared 231,663 MW (13.6 percent) of FTR buy bids, up from 155,612 MW (10.8 percent) for the 2009 to 2010 planning period. The Annual FTR Auction also cleared 10,315 MW (5.8 percent) of FTR sell offers for the 2010 to 2011 planning period, up from 7,399 MW (5.2 percent) for the 2009 to 2010 planning period. For the first seven months of the 2010 to 2011 planning period, the Monthly Balance of Planning Period FTR Auctions cleared 1,092,956 MW (12.2 percent) of FTR buy bids and 292,530 MW (10.6 percent) of FTR sell offers.

- **Price.** In the 2011 to 2014 Long Term FTR Auction, 93.3 percent of the Long Term FTRs were purchased for less than $1 per MWh and 96.7 percent for less than $2 per MWh. The weighted-average prices paid for Long Term buy-bid FTRs in the 2011 to 2014 Long Term FTR Auction were -$0.16 per MWh for 24-hour FTRs, $0.10 per MWh for on peak FTRs and $0.06 per MWh for off peak FTRs. The buy bid prices for 24 hour counter flow FTRs were negative and greater in magnitude than buy bid prices for prevailing flow FTRs in the 2011 to 2014 Long Term Auction which made the total weighted-average cleared price for 24 hour buy bid FTRs negative. Weighted-average prices paid for Long Term buy-bid FTRs in the 2010 to 2013 Long Term FTR Auction were $0.53 per MWh for 24-hour FTRs, $0.03 per MWh for on peak FTRs and $0.10 per MWh for off peak FTRs. For the 2010 to 2011 planning period, 87.4 percent of the Annual FTRs were purchased for less than $1 per MWh and 93.5 percent for less than $2 per MWh. For the 2010 to 2011 planning period, the weighted-average prices paid for annual buy-bid FTR obligations were $0.43 per MWh for 24-hour FTRs, $0.35 per MWh for on peak FTRs and $0.32 per MWh for off peak FTRs. Weighted-average prices paid for annual buy-bid FTR obligations for the 2009 to 2010 planning period were $0.66 per MWh for 24-hour FTRs and $0.57 per MWh for on peak FTRs and $0.40 per MWh for off peak FTRs. The weighted-average prices paid for 2010 to 2011 planning period annual buy-bid FTR obligations and options were $0.35 per MWh and $0.26 per MWh, respectively, compared to $0.53 per MWh and $0.35 per MWh, respectively, in the 2009 to 2010 planning period.[8] The weighted-average price paid for buy-bid FTRs in the Monthly Balance of Planning Period FTR Auctions for the first seven months of the 2010 to 2011 planning period was $0.17 per MWh, compared with $0.18 per MWh in the Monthly Balance of Planning Period FTR Auctions for the full 12-month 2009 to 2010 planning period.

- **Revenue.** The 2011 to 2014 Long Term FTR Auction generated $49.8 million of net revenue for all FTRs, up from $31.1 million in the 2010 to 2013 Long Term FTR Auction. The Annual FTR Auction generated $1,049.8 million of net revenue for all FTRs during the 2010 to 2011 planning period, down from $1,329.8 million for the 2009 to 2010 planning period. The Monthly Balance of Planning Period FTR Auctions generated $16.7 million in net revenue for all FTRs during the first seven months of the 2010 to 2011 planning period.

- **Revenue Adequacy.** FTRs were 96.9 percent revenue adequate for the 2009 to 2010 planning period. FTRs were paid at 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period. Congestion revenues are allocated to FTR holders based on FTR target allocations. PJM collected $981.4 million of FTR revenues during the first seven months of the 2010 to 2011 planning period and $878.4 million during the 2009 to 2010 planning period. For the first seven months of the 2010 to 2011 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 was the Western Hub.

- **Profitability.** FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. The cost of self scheduled FTRs is zero in the FTR profitability calculation. FTRs were profitable overall and were profitable for both physical entities and financial entities in 2010. FTR profits tended to increase in the summer and winter months when congestion was higher and decrease in the shoulder months when congestion was lower.

Auction Revenue Rights

Market Structure

- **Supply.** ARR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested ARRs and the numerous combinations of feasible ARRs. The principal binding constraints that limited supply in the annual ARR allocation for the 2010 to 2011 planning period were the AP South Interface and the Electric Junction — Nelson line. Long Term ARRs are in effect for 10 consecutive planning periods and are available in Stage 1A of the annual ARR allocation. Residual ARRs are available to holders with prorated Stage 1A or 1B ARRs if additional transmission capability is added during the planning period.

8 Weighted-average prices for FTRs in the Long Term FTR Auction, Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions are the average prices weighted by the MW and hours in a time period (planning period or month) for each FTR class type: 24-hour, on peak and off peak. For example, FTRs in the 2010 to 2011 Annual FTR Auction would be weighted by their MW and the hours in that time period for each FTR class type: 24-hour (8,760 hours), on peak (4,112 hours) and off peak (4,648 hours).

- **Demand.** Total demand in the annual ARR allocation was 135,614 MW for the 2010 to 2011 planning period with 61,793 MW bid in Stage 1A, 27,850 MW bid in Stage 1B and 45,971 MW bid in Stage 2. This is down from 140,037 MW for the 2009 to 2010 planning period with 64,987 MW bid in Stage 1A, 26,517 MW bid in Stage 1B and 48,533 MW bid in Stage 2. ARR demand is limited by the total amount of network service and firm point-to-point transmission service.

- **ARR Reassignment for Retail Load Switching.** When retail load switches among load-serving entities (LSEs), a proportional share of the ARRs and their associated revenue are reassigned from the LSE losing load to the LSE gaining load. ARR reassignment occurs only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. There were 17,831 MW of ARRs associated with approximately $269,600 per MW-day of revenue that were reassigned in the first seven months of the 2010 to 2011 planning period. There were 19,061 MW of ARRs associated with approximately $362,400 per MW-day of revenue that were reassigned for the full 2009 to 2010 planning period.

Market Performance

- **Volume.** Of 135,614 MW in ARR requests for the 2010 to 2011 planning period, 101,843 MW (75.1 percent) were allocated. There were 61,793 MW allocated in Stage 1A, 27,850 MW allocated in Stage 1B and 12,200 MW allocated in Stage 2. Eligible market participants self scheduled 55,732 MW (54.6 percent) of these allocated ARRs as Annual FTRs. Of 140,037 MW in ARR requests for the 2009 to 2010 planning period, 109,413 MW (78.1 percent) were allocated. There were 64,913 MW allocated in Stage 1A, 26,514 MW allocated in Stage 1B and 17,986 MW allocated in Stage 2. Eligible market participants self scheduled 68,589 MW (62.6 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 2010 to 2011 planning period, ARR holders will receive $1,028.8 million in ARR credits, with an average hourly ARR credit of $1.15 per MWh. During the 2010 to 2011 planning period, the ARR target allocations were $1,028.8 million while PJM collected $1,066.9 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions through December 2010, making ARRs revenue adequate. During the 2009 to 2010 planning period, ARR holders received $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh. For the 2009 to 2010 planning period, the ARR target allocations were $1,273.5 million while PJM collected $1,349.3 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate.

- **ARR Proration.** No ARRs were prorated in Stage 1A and Stage 1B for the 2010 to 2011 planning period since there were no constraints limiting the allocation in these two stages. Some of the requested ARRs were prorated in Stage 2 as a result of binding transmission constraints. For the 2009 to 2010 planning period, no ARRs were prorated in Stage 1A and Stage 1B of the annual ARR allocation.

- **ARRs and FTRs as a Hedge against Congestion.** The effectiveness of ARRs and FTRs as a hedge against actual congestion can be measured several ways. The effectiveness of

ARRs as a hedge can be measured by comparing the revenue received by ARR holders to the congestion costs experienced by these ARR holders. The effectiveness of ARRs and FTRs as a hedge against congestion can be measured by comparing the revenue received by ARR and FTR holders to total actual congestion costs in the Day-Ahead Energy Market and the balancing energy market. For the 2009 to 2010 planning period, all ARRs and FTRs hedged more than 96.2 percent of the congestion costs within PJM. During the first seven months of the 2010 to 2011 planning period, total ARR and FTR revenues hedged 78.7 percent of the congestion costs within PJM.

- **ARRs and FTRs as a Hedge against Total Energy Costs.** The hedge provided by ARRs and FTRs can also be measured by comparing the value of the ARRs and FTRs that sink in a zone to the cost of real time energy in the zone. This is a measure of the value of the hedge against real time energy costs provided by ARRs and FTRs. The total value of ARRs plus FTRs was 4.2 percent of the total real time energy charges in calendar year 2010.

Conclusion

The annual ARR allocation and the FTR auctions provide market participants with the opportunity to hedge positions or to speculate. The Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions provide a market valuation of FTRs. The FTR auction results for the 2010 to 2011 planning period were competitive and succeeded in providing all qualified market participants with equal access to FTRs.

The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. Positively valued ARRs follow load when load switches between suppliers. The self scheduled FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches in order to ensure that the new LSE is in the same competitive position as the LSE that lost load.

ARRs were 100 percent revenue adequate for both the 2009 to 2010 and the 2010 to 2011 planning periods. FTRs were paid at 96.9 percent of the target allocation level for the 12-month period of the 2009 to 2010 planning period, and at 85.2 percent of the target allocation level for the first seven months of the 2010 to 2011 planning period. Revenue adequacy for a planning period is not final until the end of the period. The MMU recommends that PJM provide more comprehensive explanations to members regarding the reasons for FTR underfunding.

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 total of ARR and FTR revenues hedged more than 96.2 percent of the congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM for the 2009 to 2010 planning period and 78.7 percent of the congestion costs in PJM for the first seven months of the

2010 to 2011 planning period. The ARR and FTR revenue adequacy results are aggregate results and all those paying congestion charges were not necessarily hedged at that level. Aggregate numbers do not reveal the underlying distribution of ARR and FTR holders, their revenues or those paying congestion.

Financial Transmission Rights

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

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the Day-Ahead Energy Market across specific FTR transmission paths. Effective June 1, 2007, PJM added marginal losses as a component in the calculation of LMP.[9] The value of an FTR reflects the difference in congestion prices rather than the difference in LMPs, which includes both congestion and marginal losses. Auction market participants are free to request FTRs between any pricing nodes on the system, including hubs, control zones, aggregates, generator buses, load buses and interface pricing points. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the Day-Ahead Energy Market. The value of an FTR can be positive or negative depending on the sink minus source congestion price difference, with a negative difference resulting in a liability for the holder. The FTR target allocation represents what the holders would receive if sufficient revenues are collected to fund FTRs.

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

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

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

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

9 For additional information on marginal losses, see the *2010 State of the Market Report for PJM*, Volume II, Section 2, “Energy Market, Part 1,” at “Marginal Losses.”

The off peak products are effective during hours ending 2400 through 0700, EPT, Mondays through Fridays, and during all hours on Saturdays, Sundays and NERC holidays.

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

Market Structure

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

Supply

Throughout the year, PJM oversees the process of selling and buying FTRs through FTR Auctions. Market participants purchase FTRs by participating in Long Term, Annual and Monthly Balance of Planning Period FTR Auctions.[10] The Annual FTR Auction includes the ability to directly convert allocated ARRs into self scheduled FTRs. Total FTR supply is limited by the capability of the transmission system to simultaneously accommodate the set of requested FTRs and the numerous combinations of FTRs that are feasible. For the Annual FTR Auction, known transmission outages that are expected to last for two months or more are included, while known outages of five days or more are included for the Monthly Balance of Planning Period FTR Auctions as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled.[11] But, the auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may not be planned in advance or may be emergency in nature. FTRs can be traded between market participants through bilateral transactions.

During the 2010 to 2011 planning period, binding transmission constraints prevented the award of all requested FTRs in the Long Term FTR Auction, the Annual FTR Auction and Monthly Balance of Planning Period FTR Auctions.[12] Table 8-2 and Table 8-3 list the top 10 binding constraints along with their corresponding control zones in the Long Term FTR Auction and the Annual FTR Auction, respectively. They are listed in order of severity, irrespective of auction round. For each of the top 10 binding constraints, a numerical ranking in order of severity for each auction round is also listed. The order of severity is determined by the marginal value of the binding constraint. The marginal value measures the value gained by relieving a constraint by 1 MW. The marginal value is computed and generated in the optimization engine for both on peak and off peak hours.[13] Table 8-2 and Table 8-3 demonstrate the marginal value for on peak hours only.

10 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 38.
11 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 54.
12 Binding constraints for Monthly Balance of Planning Period Auctions are posted to the PJM website in monthly files at <http://www.pjm.com/markets-and-operations/ftr/auction-user-info/historical-ftr-auction.aspx>.
13 See PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 57.

Table 8-2 Top 10 principal binding transmission constraints limiting the Long Term FTR Auction: Planning periods 2011 to 2014

			Severity Ranking by Auction Round		
Constraint	Type	Control Zone	1	2	3
Millville - Old Chapel	Line	AP	24	NA	1
Lovettsville - Millville	Line	AP	NA	NA	2
Doubs	Transformer	AP	1	1	NA
Rising	Flowgate	Midwest ISO	2	3	10
Bartonsville - Meadow Brook	Line	AP	3	6	13
Meadow Brook	Transformer	AP	4	7	4
Tiltonsville - West Bellaire	Line	AEP	19	2	3
Hamilton - Weirton	Line	AP	5	4	11
Roxbury - Shade Gap	Line	PENELEC	12	9	5
Millville - Sleepy Hollow	Line	AP	7	14	NA

Table 8-3 Top 10 principal binding transmission constraints limiting the Annual FTR Auction: Planning period 2010 to 2011

			Severity Ranking by Auction Round			
Constraint	Type	Control Zone	1	2	3	4
Doubs	Transformer	AP	2	1	2	1
Messick Road - Ridgeley	Line	AP	1	2	1	5
Mahans Lane - Tidd	Line	AEP	3	5	8	10
Middlebourne - Willow Island	Line	AP	4	4	4	3
AP South	Interface	AP	5	3	3	2
Endless Caverns	Transformer	Dominion	8	6	6	4
Tiltonsville - Windsor	Line	AP	43	29	7	6
Smith - Wylie Ridge	Line	AP	13	7	5	7
Roxbury - Shade Gap	Line	PENELEC	6	8	12	16
Krendale - Seneca	Line	AP	7	9	10	9

Long Term FTR Auction

PJM conducts a Long Term FTR Auction for the three consecutive planning periods immediately following the planning period during which the Long Term FTR Auction is conducted. The capacity offered for sale in Long Term FTR Auctions is the residual system capability after the assumption that all ARRs allocated in the immediately prior annual ARR allocation process are self scheduled as FTRs. These ARRs are modeled as fixed injections and withdrawals in the Long Term FTR Auction. Future transmission upgrades are not included in the model. The 2009 to 2012 and 2010 to 2013 Long Term FTR Auctions consisted of two rounds. FERC approved, on December 7, 2009, the addition of an additional round to the Long Term FTR Auction and the change in the percentage of feasible FTR available capability awarded in each round from 50 percent to one third.[14] The 2011 to 2014 Long Term FTR Auction consisted of three rounds. In each round one third of the feasible FTR available capability was awarded. FTRs purchased in prior rounds may be offered for sale in subsequent rounds.

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

- **Round 2.** The second round is conducted approximately three months after the first round.

- **Round 3.** The third round is conducted approximately three months after the second round.

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

Annual FTR Auction

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

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

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

By self scheduling ARRs as price-taking bids in the Annual FTR Auction, customers with ARRs receive FTRs for their ARR paths. ARR holders are guaranteed that they will receive their requested FTRs. ARRs can be self scheduled only as 24-hour FTR obligations. ARR holders that self schedule ARRs as FTRs still hold the associated ARR. Self scheduling transactions net out such that the ARR holder buys the FTR in the auction, receives the corresponding revenue based on holding the ARR and is left with ownership of the FTR as a hedge. The following is an illustrative example of

14 FERC order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

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

self scheduling ARRs as FTRs. An ARR holder has received an allocation of 1 MW from source A to sink B. The ARR holder self schedules the 1 MW allocated ARR as an FTR. In the Annual FTR Auction, the price for a 1 MW FTR from A to B is $100. The ARR holder pays $100 to buy the 1 MW FTR in the Annual FTR Auction, but receives a $100 ARR target credit based on the associated 1 MW ARR. In addition, the ARR holder obtains the corresponding FTR target allocation as a hedge.

Monthly Balance of Planning Period FTR Auctions

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

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

Secondary Bilateral Market

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

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

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

Demand

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

FTR Credit Issues

Default

No participants defaulted in 2010.

FTR Credit Rules

Following a series of high profile defaults, PJM made significant reforms to its credit policies in 2007–2009.[17] Among other things, PJM reduced available unsecured credit, and eliminated the FTR Unsecured Credit Allowance in PJM's FTR markets.[18] On May 4, 2010, PJM submitted a filing[19] that would have restored an FTR Unsecured Credit Allowance "as it relates to certain LSE transactions involving counterflow FTRs."[20] The Commission rejected the proposal because PJM did not explain how it protects PJM from "the unbounded energy price risk that is solely the result of the LSE holding the counterflow FTR, a risk that should be collateralized in the same way it would be if the counterflow FTR was held by any other entity."[21]

The current rules continue to allow Seller Credit, a form of unsecured credit, to cover obligations in the FTR and other markets and permit an Unsecured Credit Allowance up to $50 million to cover non FTR obligations.[22] The MMU continues to recommend the complete elimination of unsecured credit, over an appropriate transition period, based on the MMU's view of PJM's role in evaluating the credit worthiness of complex corporate entities and due to a concern about inappropriate shifts of risks and costs among PJM members. For the same reasons, the MMU recommends that PJM not reintroduce any additional allowance for unsecured credit in the FTR markets.

Patterns of Ownership

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

17 *See* 127 FERC ¶ 61,017 (2009).

18 *Id.* at PP 36–37.

19 PJM compliance filing in ER09-650-002. In response to the assertions of certain LSEs that "PJM's elimination of unsecured credit for LSEs that use counterflow FTRs to hedge purchases to serve load far exceed the risks attendant to this practice because the LSEs have physical assets that reduce the risk of default," PJM answered that "a modification to its collateral provisions with respect to LSEs is warranted." 127 FERC ¶ 61,017 at P 37. The Commission took note and required PJM to file "an explanation of what reductions are appropriate for LSEs along with the proposed tariff revisions it believes are warranted." *Id.*

20 See 131 FERC ¶ 61,017 at P 31 (2010).

21 *Id.* at PP 33–34.

22 See OATT Attachment Q § V.A & II.B; see also 127 FERC ¶ 61,017 at P 34.

The ownership concentration of cleared FTR buy bids resulting from the 2010 to 2011 Annual FTR Auction was low to moderate for FTR obligations and moderate to high for FTR options.

For cleared FTR buy-bid obligations in the 2010 to 2011 Annual FTR Auction, the HHIs were 1518 for 24-hour, 615 for on peak and 674 for off peak FTR products while maximum market shares were 25 percent for 24-hour, which is associated with a physical entity, 14 percent for on peak, which is associated with a financial entity, and 15 percent for off peak FTR products, which is associated with a financial entity, and 15 percent for off peak FTR products, which is associated with a financial entity.

For cleared FTR buy-bid options in the 2010 to 2011 Annual FTR Auction, HHIs were 2517 for 24-hour, 1602 for on peak and 2232 for off peak products while maximum market shares were 28 percent for 24-hour, which is associated with a physical entity, 28 percent for on peak, which is associated with a physical entity, and 42 percent for off peak FTR products, which is associated with a physical entity.

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

Table 8-4 presents the 2011 to 2014 Long Term FTR Auction market cleared FTRs by trade type, organization type and FTR direction. The results show that financial entities own 80 percent of prevailing flow cleared buy bid FTRs and 89 percent of counter flow cleared buy bid FTRs. Overall, financial entities own about 84 percent of all Long Term cleared buy bid FTRs.

Table 8-4 Long Term FTR Auction patterns of ownership by FTR direction: Planning periods 2011 to 2014[23]

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	20.3%	11.5%	16.2%
	Financial	79.7%	88.5%	83.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	14.9%	25.4%	16.5%
	Financial	85.1%	74.6%	83.5%
	Total	100.0%	100.0%	100.0%

23 Table 8-4, Table 8-5 and Table 8-6 are updated from previous State of the Market Reports to include trade type. Previous versions of these tables netted the buy and sell MW by FTR and organization. This created organizations with FTRs that had a net negative MW volume in the respective auction.

Table 8-5 presents the Annual FTR Auction market cleared FTRs in the 2010 to 2011 planning period by trade type, organization type and FTR direction. The results show that physical entities own 54 percent of prevailing flow cleared buy bid FTRs while financial entities own 72 percent of counter flow cleared buy bid FTRs. In the 2010 to 2011 Annual FTR Auction physical entities own 13 percent of all sold FTRs while financial entities own 87 percent of all sold FTRs.

Table 8-5 Annual FTR Auction patterns of ownership by FTR direction: Planning period 2010 to 2011

			FTR Direction		
Trade Type	Organization Type	Self-Scheduled FTRs	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	Yes	26.0%	2.8%	19.4%
		No	27.9%	25.5%	27.2%
		Total	53.9%	28.2%	46.6%
	Financial	No	46.1%	71.8%	53.4%
	Total		100.0%	100.0%	100.0%
Sell Offers	Physical		10.8%	21.4%	13.3%
	Financial		89.2%	78.6%	86.7%
	Total		100.0%	100.0%	100.0%

Table 8-6 presents the Monthly Balance of Planning Period FTR Auction market cleared FTRs in calendar year 2010 by trade type, organization type and FTR direction. The results show that physical entities own only 13 percent of counter flow cleared buy bid FTRs while financial entities own 87 percent. Overall, financial entities own 82 percent of all Monthly Balance of Planning Period cleared buy bid FTRs.

Table 8-6 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: Calendar year 2010

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	22.8%	12.6%	17.6%
	Financial	77.2%	87.4%	82.4%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	47.2%	26.6%	43.7%
	Financial	52.8%	73.4%	56.3%
	Total	100.0%	100.0%	100.0%

Table 8-7 presents the daily FTR net position ownership in 2010 by FTR direction. The net position of all FTRs, including all auctions, is calculated for every organization each day. The data is summarized for the 2010 calendar year to show the ownership patterns by FTR direction. Physical entities owned 54 percent of all prevailing flow FTRs and 32 percent of counter flow FTRs in 2010.

Table 8-7 Daily FTR net position ownership by FTR direction: Calendar year 2010

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	54.2%	31.7%	48.5%
Financial	45.8%	68.3%	51.5%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

Table 8-8 shows the 2011 to 2014 Long Term FTR Auction volume by trade type, FTR direction and period type.[24] The total volume was 1,996,084 MW for FTR buy bids and 177,540 MW for FTR sell offers in the 2011 to 2014 Long Term FTR Auction. This is up from the total volume of 1,064,620 MW for FTR buy bids and 51,582 MW for FTR sell offers in the 2010 to 2013 Long Term FTR Auction.

The 2011 to 2014 Long Term FTR Auction cleared 238,681 MW (12.0 percent) leaving 1,757,403 MW (88.0 percent) of uncleared FTR buy bids. There were 12,501 MW (7.0 percent) of cleared FTR sell offers leaving 165,039 MW (93.0 percent) of uncleared FTR sell offers. This is up from the total of 86,108 MW (8.1 percent) of cleared FTR buy bids and 5,147 MW (10.0 percent) of cleared FTR sell offers in the 2010 to 2013 Long Term FTR Auction.

In the 2011 to 2014 Long Term FTR Auction, there were 111,913 MW (31.9 percent) cleared out of 350,458 MW counter flow FTR buy bids and 126,769 MW (7.7 percent) cleared out of 1,645,626 MW prevailing flow FTR buy bids. In the 2011 to 2014 Long Term FTR Auction, there were 1,938 MW (3.2 percent) cleared out of 61,079 MW counter flow FTR sell offers and 10,564 MW (9.1 percent) cleared out of 116,461 MW prevailing flow FTR offers.

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

Table 8-8 Long Term FTR Auction market volume: Planning periods 2011 to 2014

Trade Type	FTR Direction	Period Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Counter Flow	Year 1	44,923	156,093	52,811	33.8%	103,283	66.2%
		Year 2	34,337	113,985	38,863	34.1%	75,122	65.9%
		Year 3	24,013	79,930	20,036	25.1%	59,893	74.9%
		Year All	13	451	203	45.0%	248	55.0%
		Total	103,286	350,458	111,913	31.9%	238,546	68.1%
	Prevailing Flow	Year 1	127,194	682,654	57,130	8.4%	625,525	91.6%
		Year 2	96,216	521,894	37,764	7.2%	484,130	92.8%
		Year 3	73,515	441,043	31,874	7.2%	409,169	92.8%
		Year All	11	35	1	2.9%	34	97.1%
		Total	296,936	1,645,626	126,769	7.7%	1,518,857	92.3%
	Total		400,222	1,996,084	238,681	12.0%	1,757,403	88.0%
Sell offers	Counter Flow	Year 1	8,733	31,541	1,172	3.7%	30,370	96.3%
		Year 2	6,024	19,553	672	3.4%	18,881	96.6%
		Year 3	2,606	9,985	95	0.9%	9,891	99.1%
		Year All	NA	NA	NA	NA	NA	NA
		Total	17,363	61,079	1,938	3.2%	59,142	96.8%
	Prevailing Flow	Year 1	15,074	58,542	5,886	10.1%	52,656	89.9%
		Year 2	11,484	44,735	4,195	9.4%	40,539	90.6%
		Year 3	3,949	13,184	482	3.7%	12,702	96.3%
		Year All	NA	NA	NA	NA	NA	NA
		Total	30,507	116,461	10,564	9.1%	105,897	90.9%
	Total		47,870	177,540	12,501	7.0%	165,039	93.0%

Table 8-9 shows the Annual FTR Auction volume by trade type, hedge type and FTR direction for the 2010 to 2011 planning period. The total volume was 1,708,556 MW for FTR buy bids and 178,428 MW for FTR sell offers for the 2010 to 2011 planning period. This is up from the total volume of 1,436,335 MW for FTR buy bids and up from 142,154 MW for FTR sell offers for the 2009 to 2010 planning period.

There were 231,663 MW (13.6 percent) of cleared FTR buy bids and 10,315 MW (5.8 percent) of cleared FTR sell offers for the 2010 to 2011 planning period. This is up from the total of 155,612 MW (10.8 percent) of cleared FTR buy bids and up from 7,399 MW (5.2 percent) of cleared FTR sell offers for the 2009 to 2010 planning period.

For the 2010 to 2011 planning period, there were 79,411 MW (25.5 percent) cleared out of 310,940 MW counter flow FTR buy bids and 152,251 MW (10.9 percent) cleared out of 1,397,616 MW prevailing flow FTR buy bids. During the 2010 to 2011 planning period, there were 2,360 MW

(3.7 percent) cleared out of 64,026 MW counter flow FTR sell offers and 7,955 MW (7.0 percent) cleared out of 114,402 MW prevailing flow FTR offers.

Table 8-9 Annual FTR Auction market volume: Planning period 2010 to 2011

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Buy bids	Obligations	Counter Flow	76,794	300,085	73,956	24.6%	226,129	75.4%
		Prevailing Flow	195,599	1,233,329	127,366	10.3%	1,105,963	89.7%
		Total	272,393	1,533,414	201,322	13.1%	1,332,092	86.9%
	Options	Counter Flow	100	10,855	5,455	50.3%	5,400	49.7%
		Prevailing Flow	7,569	164,287	24,885	15.1%	139,402	84.9%
		Total	7,669	175,142	30,340	17.3%	144,802	82.7%
	Total	Counter Flow	76,894	310,940	79,411	25.5%	231,529	74.5%
		Prevailing Flow	203,168	1,397,616	152,251	10.9%	1,245,365	89.1%
		Total	280,062	1,708,556	231,663	13.6%	1,476,893	86.4%
Self-scheduled bids	Obligations	Counter Flow	160	2,253	2,253	100.0%	0	0.0%
		Prevailing Flow	8,644	53,479	53,479	100.0%	0	0.0%
		Total	8,804	55,732	55,732	100.0%	0	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	76,954	302,338	76,209	25.2%	226,129	74.8%
		Prevailing Flow	204,243	1,286,808	180,845	14.1%	1,105,963	85.9%
		Total	281,197	1,589,146	257,054	16.2%	1,332,092	83.8%
	Options	Counter Flow	100	10,855	5,455	50.3%	5,400	49.7%
		Prevailing Flow	7,569	164,287	24,885	15.1%	139,402	84.9%
		Total	7,669	175,142	30,340	17.3%	144,802	82.7%
	Total	Counter Flow	77,054	313,193	81,664	26.1%	231,529	73.9%
		Prevailing Flow	211,812	1,451,095	205,730	14.2%	1,245,365	85.8%
		Total	288,866	1,764,288	287,394	16.3%	1,476,893	83.7%
Sell offers	Obligations	Counter Flow	18,898	60,966	2,360	3.9%	58,606	96.1%
		Prevailing Flow	28,599	106,947	7,914	7.4%	99,033	92.6%
		Total	47,497	167,912	10,274	6.1%	157,638	93.9%
	Options	Counter Flow	136	3,060	0	0.0%	3,060	100.0%
		Prevailing Flow	1,747	7,455	41	0.5%	7,415	99.5%
		Total	1,883	10,515	41	0.4%	10,475	99.6%
	Total	Counter Flow	19,034	64,026	2,360	3.7%	61,666	96.3%
		Prevailing Flow	30,346	114,402	7,955	7.0%	106,447	93.0%
		Total	49,380	178,428	10,315	5.8%	168,113	94.2%

Table 8-10 shows that for the 2010 to 2011 planning period, eligible market participants converted 55,732 MW of ARRs out of a possible 102,046 MW into Annual FTRs. In comparison, during the

2009 to 2010 planning period, eligible market participants converted 68,589 MW of ARRs out of a possible 109,612 MW.

Table 8-10 Comparison of self scheduled FTRs: Planning periods 2008 to 2009, 2009 to 2010 and 2010 to 2011[25]

Planning Period	Self-Scheduled FTRs (MW)	Maximum Possible Self-Scheduled FTRs (MW)	Percent of ARRs Self-Scheduled as FTRs
2008/2009	72,851	112,011	65.0%
2009/2010	68,589	109,612	62.6%
2010/2011	55,732	102,046	54.6%

Table 8-11 shows that there were 7,952,347 MW of FTR buy bid obligations and 2,367,724 MW of FTR sell offer obligations for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2010 to 2011 planning period through December 31, 2010. The monthly auctions cleared 1,058,610 MW (13.3 percent) leaving 6,893,737 MW (86.7 percent) of uncleared FTR buy bid obligations. There were 196,280 MW (8.3 percent) of cleared FTR sell offer obligations leaving 2,171,444 MW (91.7 percent) of uncleared FTR sell offer obligations.

There were 1,021,298 MW of FTR buy bid options and 399,004 MW of FTR sell offer options for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the 2010 to 2011 planning period through December 31, 2010. The monthly auctions cleared 34,346 MW (3.4 percent) leaving 986,952 MW (96.6 percent) of uncleared FTR buy bid options. There were 96,250 MW (24.1 percent) of cleared FTR sell offer options leaving 302,754 MW (75.9 percent) of uncleared FTR sell offer options.

The Monthly Balance of Planning Period FTR Auctions for the full 12-month 2009 to 2010 planning period had a total demand of 8,219,996 MW for FTR buy bids and 2,795,964 MW for FTR sell offers. The monthly auctions cleared 963,301 MW (11.7 percent) of FTR buy bids and 254,145 MW (9.1 percent) of FTR sell offers.

25 The column Maximum Possible Self-Scheduled FTRs in Table 8-4 is updated from the *2009 State of the Market Report* to include RTEP IARR MW. RTEP IARRs and ARRs can be self-scheduled in round 1 of the Annual FTR Auction.

Table 8-11 Monthly Balance of Planning Period FTR Auction market volume: Calendar year 2010

Monthly Auction	Hedge Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-10	Obligations	Buy bids	156,274	716,812	79,724	11.1%	637,088	88.9%
		Sell offers	46,206	165,858	11,224	6.8%	154,635	93.2%
	Options	Buy bids	391	11,953	1,621	13.6%	10,332	86.4%
		Sell offers	1,579	33,020	5,686	17.2%	27,334	82.8%
Feb-10	Obligations	Buy bids	129,946	656,279	78,354	11.9%	577,925	88.1%
		Sell offers	40,605	146,757	10,364	7.1%	136,393	92.9%
	Options	Buy bids	622	13,993	1,119	8.0%	12,874	92.0%
		Sell offers	1,702	33,125	6,955	21.0%	26,170	79.0%
Mar-10	Obligations	Buy bids	120,727	607,270	90,189	14.9%	517,081	85.1%
		Sell offers	56,858	201,797	12,542	6.2%	189,255	93.8%
	Options	Buy bids	331	8,420	749	8.9%	7,672	91.1%
		Sell offers	1,224	23,960	5,326	22.2%	18,634	77.8%
Apr-10	Obligations	Buy bids	104,078	483,995	78,853	16.3%	405,142	83.7%
		Sell offers	30,097	127,238	9,844	7.7%	117,394	92.3%
	Options	Buy bids	185	5,643	481	8.5%	5,161	91.5%
		Sell offers	980	17,098	3,474	20.3%	13,6 25	79.7%
May-10	Obligations	Buy bids	83,069	372,583	63,260	17.0%	309,323	83.0%
		Sell offers	16,709	74,617	8,385	11.2%	66,233	88.8%
	Options	Buy bids	396	3,229	209	6.5%	3,020	93.5%
		Sell offers	623	9,657	3,049	31.6%	6,609	68.4%
Jun-10	Obligations	Buy bids	204,305	998,923	107,676	10.8%	891,247	89.2%
		Sell offers	94,433	417,735	24,228	5.8%	393,507	94.2%
	Options	Buy bids	1,725	66,735	2,932	4.4%	63,804	95.6%
		Sell offers	11,073	69,691	15,816	22.7%	53,874	77.3%
Jul-10	Obligations	Buy bids	225,737	1,108,721	146,069	13.2%	962,652	86.8%
		Sell offers	75,886	359,722	29,406	8.2%	330,316	91.8%
	Options	Buy bids	878	37,271	2,304	6.2%	34,967	93.8%
		Sell offers	8,089	66,097	16,084	24.3%	50,013	75.7%
Aug-10	Obligations	Buy bids	222,224	1,118,261	126,436	11.3%	991,825	88.7%
		Sell offers	65,197	300,616	23,909	8.0%	276,706	92.0%
	Options	Buy bids	2,532	83,876	4,233	5.0%	79,643	95.0%
		Sell offers	6,321	42,262	13,534	32.0%	28,728	68.0%
Sep-10	Obligations	Buy bids	232,043	1,282,913	185,736	14.5%	1,097,177	85.5%
		Sell offers	76,919	364,793	31,628	8.7%	333,165	91.3%
	Options	Buy bids	1,681	227,899	5,366	2.4%	222,533	97.6%
		Sell offers	8,339	66,072	15,052	22.8%	51,020	77.2%
Oct-10	Obligations	Buy bids	235,014	1,203,102	161,265	13.4%	1,041,838	86.6%
		Sell offers	70,209	338,218	33,245	9.8%	304,973	90.2%
	Options	Buy bids	1,602	224,392	4,815	2.1%	219,577	97.9%
		Sell offers	6,527	47,851	12,554	26.2%	35,297	73.8%
Nov-10	Obligations	Buy bids	206,106	1,077,866	143,928	13.4%	933,938	86.6%
		Sell offers	60,323	285,972	25,150	8.8%	260,822	91.2%
	Options	Buy bids	1,476	184,103	3,277	1.8%	180,826	98.2%
		Sell offers	5,111	53,552	10,613	19.8%	42,940	80.2%
Dec-10	Obligations	Buy bids	197,579	1,162,560	187,500	16.1%	975,061	83.9%
		Sell offers	59,942	300,668	28,713	9.5%	271,955	90.5%
	Options	Buy bids	1,493	197,022	11,418	5.8%	185,604	94.2%
		Sell offers	3,780	53,478	12,596	23.6%	40,882	76.4%
2009/2010*	Obligations	Buy bids	1,908,766	8,003,573	946,107	11.8%	7,057,466	88.2%
		Sell offers	649,057	2,337,381	181,810	7.8%	2,155,571	92.2%
	Options	Buy bids	4,904	216,423	17,194	7.9%	199,228	92.1%
		Sell offers	29,328	458,584	72,335	15.8%	386,248	84.2%
2010/2011**	Obligations	Buy bids	1,523,008	7,952,347	1,058,610	13.3%	6,893,737	86.7%
		Sell offers	502,909	2,367,724	196,280	8.3%	2,171,444	91.7%
	Options	Buy bids	11,387	1,021,298	34,346	3.4%	986,952	96.6%
		Sell offers	49,240	399,004	96,250	24.1%	302,754	75.9%

* Shows Twelve Months for 2009/2010; ** Shows seven months ended 31-Dec-2010 for 2010/2011

Table 8-12 shows the bid and cleared volume for FTR buy bids in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2010 through December 2010.

Table 8-12 Monthly Balance of Planning Period FTR Auction buy-bid bid and cleared volume (MW per period): Calendar year 2010

Monthly Auction	MW Type	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-10	Bid	393,426	127,235	90,338				117,766	728,765
	Cleared	55,052	10,039	5,963				10,290	81,345
Feb-10	Bid	363,548	100,591	91,281				114,853	670,272
	Cleared	53,791	9,948	6,304				9,430	79,473
Mar-10	Bid	374,155	108,329	106,100				27,107	615,690
	Cleared	66,676	10,555	9,864				3,842	90,938
Apr-10	Bid	366,026	123,612						489,638
	Cleared	67,471	11,863						79,334
May-10	Bid	375,812							375,812
	Cleared	63,469							63,469
Jun-10	Bid	398,343	134,107	127,474	27,614	129,012	126,849	122,260	1,065,658
	Cleared	65,245	9,590	9,386	2,996	10,408	7,927	5,054	110,608
Jul-10	Bid	529,368	142,953	88,143		129,524	130,924	125,079	1,145,991
	Cleared	86,820	15,281	8,068		13,336	12,559	12,309	148,373
Aug-10	Bid	566,562	113,783	102,176		130,975	140,738	147,904	1,202,137
	Cleared	76,858	10,504	9,822		8,898	11,733	12,854	130,669
Sep-10	Bid	618,218	186,274	173,686		96,649	215,233	220,751	1,510,812
	Cleared	117,485	18,384	18,820		6,981	13,593	15,840	191,103
Oct-10	Bid	622,634	198,680	148,300			222,780	235,100	1,427,494
	Cleared	106,177	19,546	7,534			14,624	18,198	166,080
Nov-10	Bid	589,936	166,937	162,232			158,176	184,688	1,261,969
	Cleared	103,683	9,552	10,198			9,967	13,805	147,205
Dec-10	Bid	688,892	207,805	208,802			48,339	205,745	1,359,582
	Cleared	130,921	22,546	23,781			4,320	17,351	198,918

Table 8-13 shows the secondary bilateral FTR market volume by hedge type and class type for the 2009 to 2010 and the 2010 to 2011 planning periods. There were 24,054 MW of total bilateral FTR activity for the 2010 to 2011 planning period through December 31, 2010, while there were 8,840 MW during the 2009 to 2010 planning period. Price data is not meaningful as PJM market participants enter zero as the price for more than 93 percent of secondary bilateral FTR transactions.

Table 8-13 Secondary bilateral FTR market volume : Planning periods 2009 to 2010 and 2010 to 2011[26]

Planning Period	Hedge Type	Class Type	Volume (MW)
2009/2010	Obligation	24-Hour	1,468
		On Peak	3,544
		Off Peak	3,798
		Total	8,810
	Option	24-Hour	30
		On Peak	0
		Off Peak	0
		Total	30
2010/2011*	Obligation	24-Hour	1,687
		On Peak	10,035
		Off Peak	12,313
		Total	24,034
	Option	24-Hour	20
		On Peak	0
		Off Peak	0
		Total	20

* Shows seven months ended 31-Dec-2010

Price

Table 8-14 shows the cleared, weighted-average prices by trade type, FTR direction, period type and class type for the 2011 to 2014 Long Term FTR Auction. Only FTR obligation products are available in Long Term FTR Auctions. In this auction, weighted-average, buy-bid FTR prices were $0.06 per MWh while weighted-average sell offer FTR prices were $0.30 per MWh. Comparable weighted-average, buy-bid FTR prices were $0.10 per MWh while weighted-average sell offer FTR prices were $0.35 per MWh in the 2010 to 2013 Long Term FTR Auction.

26 The 2010 to 2011 planning period covers the 2010 to 2011 Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions through the December 2010 FTR Auction.

Table 8-14 Long Term FTR Auction weighted-average cleared prices (Dollars per MWh): Planning periods 2011 to 2014

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($1.57)	($0.28)	($0.24)	($0.36)
		Year 2	($1.20)	($0.26)	($0.21)	($0.32)
		Year 3	($1.21)	($0.48)	($0.35)	($0.51)
		Year All	NA	($0.46)	($0.02)	($0.27)
		Total	($1.36)	($0.31)	($0.25)	($0.38)
	Prevailing Flow	Year 1	$0.80	$0.45	$0.38	$0.45
		Year 2	$1.22	$0.45	$0.31	$0.44
		Year 3	$1.05	$0.49	$0.32	$0.46
		Year All	NA	$3.63	NA	$3.63
		Total	$0.98	$0.46	$0.34	$0.45
	Total		($0.16)	$0.10	$0.06	$0.06
Sell offers	Counter Flow	Year 1	($0.14)	($0.37)	($0.72)	($0.51)
		Year 2	($0.28)	($0.21)	($0.11)	($0.16)
		Year 3	NA	($0.34)	($0.16)	($0.27)
		Year All	NA	NA	NA	NA
		Total	($0.24)	($0.32)	($0.44)	($0.37)
	Prevailing Flow	Year 1	$0.20	$0.60	$0.34	$0.47
		Year 2	$0.09	$0.47	$0.24	$0.36
		Year 3	NA	$0.64	$0.27	$0.38
		Year All	NA	NA	NA	NA
		Total	$0.15	$0.55	$0.30	$0.42
	Total		($0.04)	$0.40	$0.19	$0.30

The 2011 to 2014 Long Term FTR Auction price duration curve for cleared buy bids in Figure 8-1 shows that 93.3 percent of Long Term FTRs were purchased for less than $1 per MWh, 96.7 percent for less than $2 per MWh and 98.4 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs).

Figure 8-1 Long Term FTR auction clearing price duration curve: Planning periods 2011 to 2014

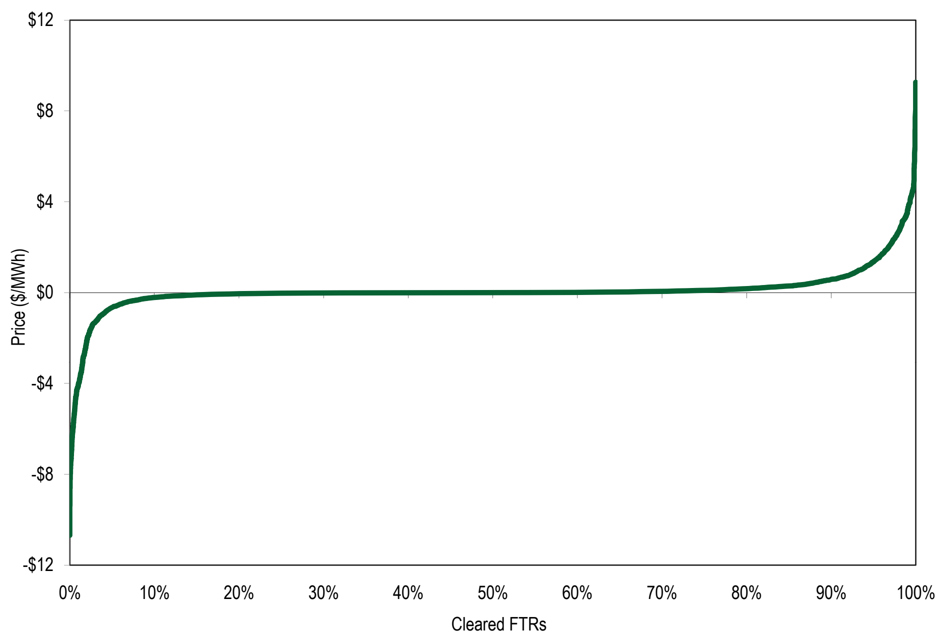


Table 8-15 shows the cleared, weighted-average prices by trade type, hedge type, FTR direction and class type for Annual FTRs during the 2010 to 2011 planning period. For the 2010 to 2011 planning period, weighted-average, buy-bid FTR obligation prices were $0.35 per MWh while weighted-average, buy-bid FTR option prices were $0.26 per MWh. Comparable weighted-average prices for the 2009 to 2010 planning period were $0.53 per MWh for buy-bid FTR obligations and $0.35 per MWh for buy-bid FTR options.

During the 2010 to 2011 planning period, weighted-average sell offer FTR obligation prices were $0.22 per MWh while weighted-average sell offer FTR option prices were $0.66 per MWh. Comparable weighted-average prices for the 2009 to 2010 planning period were $0.28 per MWh for sell offer FTR obligations and $0.11 per MWh for sell offer FTR options.

On average during the 2010 to 2011 planning period in the Annual FTR Auction, self scheduled FTRs were priced $1.06 per MWh higher than buy-bid obligation FTRs. They were priced $1.05 per MWh less than the cleared, weighted-average price of self scheduled FTRs during the 2009 to 2010 planning period.

During the 2010 to 2011 planning period, weighted-average, buy-bid FTR obligation prices were -$0.35 per MWh for counter flow FTRs and $0.75 per MWh for prevailing flow FTRs. Weighted-average sell offer FTR obligation prices were -$0.47 per MWh for counter flow FTRs and $0.43 per MWh for prevailing flow FTRs during the 2010 to 2011 planning period. On average during the 2010 to 2011 planning period in the Annual FTR Auction, self scheduled counter flow FTRs were priced $0.20 per MWh higher than buy-bid counter flow obligation FTRs and self scheduled prevailing FTRs were priced $0.72 per MWh higher than buy-bid prevailing flow obligation FTRs.

Table 8-15 Annual FTR Auction weighted-average cleared prices (Dollars per MWh): Planning period 2010 to 2011

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.56)	($0.34)	($0.28)	($0.35)
		Prevailing Flow	$0.97	$0.73	$0.69	$0.75
		Total	$0.43	$0.35	$0.32	$0.35
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.00	$0.41	$0.17	$0.31
		Total	$1.00	$0.33	$0.14	$0.26
Self-scheduled bids	Obligations	Counter Flow	($0.15)	NA	NA	($0.15)
		Prevailing Flow	$1.48	NA	NA	$1.48
		Total	$1.41	NA	NA	$1.41
Buy and self-scheduled bids	Obligations	Counter Flow	($0.46)	($0.34)	($0.28)	($0.34)
		Prevailing Flow	$1.38	$0.73	$0.69	$1.07
		Total	$1.17	$0.35	$0.32	$0.71
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$1.00	$0.41	$0.17	$0.31
		Total	$1.00	$0.33	$0.14	$0.26
Sell offers	Obligations	Counter Flow	($0.15)	($0.57)	($0.43)	($0.47)
		Prevailing Flow	$0.45	$0.53	$0.32	$0.43
		Total	$0.22	$0.32	$0.12	$0.22
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$1.11	$0.33	$0.66
		Total	$0.00	$1.11	$0.33	$0.66

The 2010 to 2011 planning period price duration curve for cleared buy bids in Figure 8-2 shows that 87.4 percent of Annual FTRs were purchased for less than $1 per MWh, 93.5 percent for less than $2 per MWh and 96.3 percent for less than $3 per MWh. Negative prices occur because some FTRs are bid with negative prices and some winning FTR bidders are paid to take FTRs (counter flow FTRs). The 2010 to 2011 planning period FTR obligation price duration curve for cleared buy bids in Figure 8-2 shows that 86.2 percent of annual FTR obligations were purchased for less than $1 per MWh, 92.7 percent for less than $2 per MWh and 95.9 percent for less than $3 per MWh. The 2010 to 2011 planning period FTR option price duration curve for cleared buy bids in Figure 8-2 shows that 95 percent of annual FTR options were purchased for less than $1 per MWh, 98.6 percent for less than $2 per MWh and 99.1 percent for less than $3 per MWh.

Figure 8-2 Annual FTR auction clearing price duration curves: Planning period 2010 to 2011

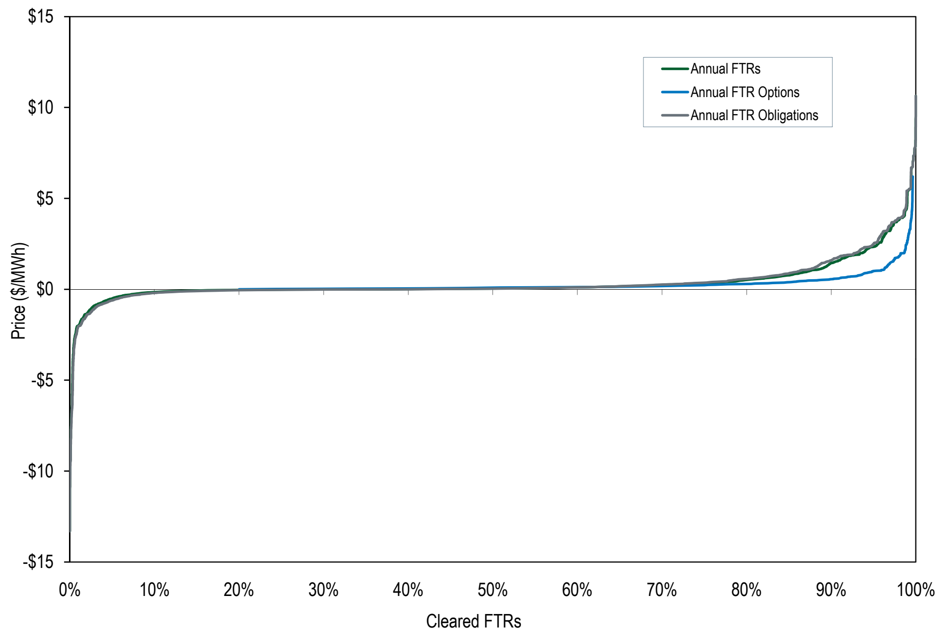


Table 8-16 shows the weighted-average cleared buy-bid price in the Monthly Balance of Planning Period FTR Auctions by bidding period for January 2010 through December 2010. For example, for the June 2010 Monthly Balance of Planning Period FTR Auction, the current month column is June, the second month column is July and the third month column is August. Quarters 1 through 4 are represented in the Q1, Q2, Q3 and Q4 columns. The total column represents all of the activity within the June 2010 Monthly Balance of Planning Period FTR Auction.

The cleared, weighted-average price paid in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2010 to 2011 planning period was $0.17 per MWh, compared with $0.18 per MWh for the full 12-month 2009 to 2010 planning period.

Table 8-16 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy-bid price per period (Dollars per MWh): Calendar year 2010

Monthly Auction	Current Month	Second Month	Third Month	Q1	Q2	Q3	Q4	Total
Jan-10	$0.09	$0.34	($0.01)				$0.16	$0.13
Feb-10	$0.09	$0.31	$0.17				$0.31	$0.19
Mar-10	$0.14	$0.30	$0.34				($0.07)	$0.15
Apr-10	$0.10	$0.24						$0.12
May-10	$0.06							$0.06
Jun-10	$0.11	$0.36	$0.35	$0.80	$0.33	$0.40	$0.37	$0.29
Jul-10	$0.14	$0.46	$0.04		$0.19	$0.16	$0.15	$0.17
Aug-10	$0.19	$0.36	$0.18		$0.20	$0.35	$0.13	$0.22
Sep-10	$0.13	$0.17	$0.15		$0.09	$0.20	$0.14	$0.14
Oct-10	$0.13	$0.18	$0.01			$0.15	$0.09	$0.13
Nov-10	$0.13	$0.19	$0.19			$0.22	$0.21	$0.17
Dec-10	$0.10	$0.23	$0.18			$0.33	$0.16	$0.14

Revenue

Long Term FTR Auction Revenue

Table 8-17 shows Long Term FTR Auction revenue data by trade type, FTR direction, period type, and class type. The 2011 to 2014 Long Term FTR Auction netted $49.80 million in revenue, with buyers paying $66.20 million and sellers receiving $16.40 million. The 2010 to 2013 Long Term FTR Auction netted $31.14 million in revenue, with buyers paying $39.12 million and sellers receiving $7.97 million.

For the 2011 to 2014 Long Term FTR Auction, the counter flow FTRs netted -$189.67 million in revenue, with buyers receiving $192.81 million and sellers paying $3.14 million, and the prevailing flow FTRs netted $239.47 million in revenue, with buyers paying $259.01 million and sellers receiving $19.54 million.

Table 8-17 Long Term FTR Auction revenue: Planning periods 2011 to 2014

			Class Type			
Trade Type	FTR Direction	Period Type	24-Hour	On Peak	Off Peak	All
Buy bids	Counter Flow	Year 1	($29,698,450)	($28,139,840)	($29,384,704)	($87,222,995)
		Year 2	($19,181,431)	($21,548,424)	($16,822,643)	($57,552,498)
		Year 3	($13,015,646)	($20,938,271)	($13,385,773)	($47,339,690)
		Year All	$0	($675,365)	($23,149)	($698,514)
		Total	($61,895,527)	($71,301,900)	($59,616,270)	($192,813,696)
	Prevailing Flow	Year 1	$17,659,087	$52,520,425	$46,201,694	$116,381,205
		Year 2	$17,140,359	$34,083,294	$25,225,411	$76,449,064
		Year 3	$12,356,411	$33,193,204	$20,590,182	$66,139,797
		Year All	$0	$44,582	$0	$44,582
		Total	$47,155,857	$119,841,504	$92,017,287	$259,014,648
	Total		($14,739,670)	$48,539,604	$32,401,018	$66,200,952
Sell offers	Counter Flow	Year 1	($1,818)	($1,149,506)	($1,413,501)	($2,564,825)
		Year 2	($9,872)	($284,126)	($173,171)	($467,169)
		Year 3	0	($88,598)	($22,229)	($110,827)
		Year All	NA	NA	NA	NA
		Total	($11,690)	($1,522,230)	($1,608,901)	($3,142,821)
	Prevailing Flow	Year 1	$5,305	$7,874,897	$4,196,589	$12,076,791
		Year 2	$2,314	$4,582,634	$2,057,947	$6,642,894
		Year 3	0	$423,284	$398,511	$821,795
		Year All	NA	NA	NA	NA
		Total	$7,619	$12,880,814	$6,653,047	$19,541,480
	Total		($4,072)	$11,358,584	$5,044,146	$16,398,659

Figure 8-3 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the 2011 to 2014 Long Term FTR Auction.[27] The top 10 positive revenue producing FTR sinks accounted for $91.11 million of the total revenue of $49.80 million paid in the auction.[28] They also comprised 9.7 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing FTR sinks accounted for -$60.00 million of revenue and constituted 2.5 percent of all FTRs bought in the auction.

Figure 8-3 Ten largest positive and negative revenue producing FTR sinks purchased in the Long Term FTR Auction: Planning periods 2011 to 2014[29]

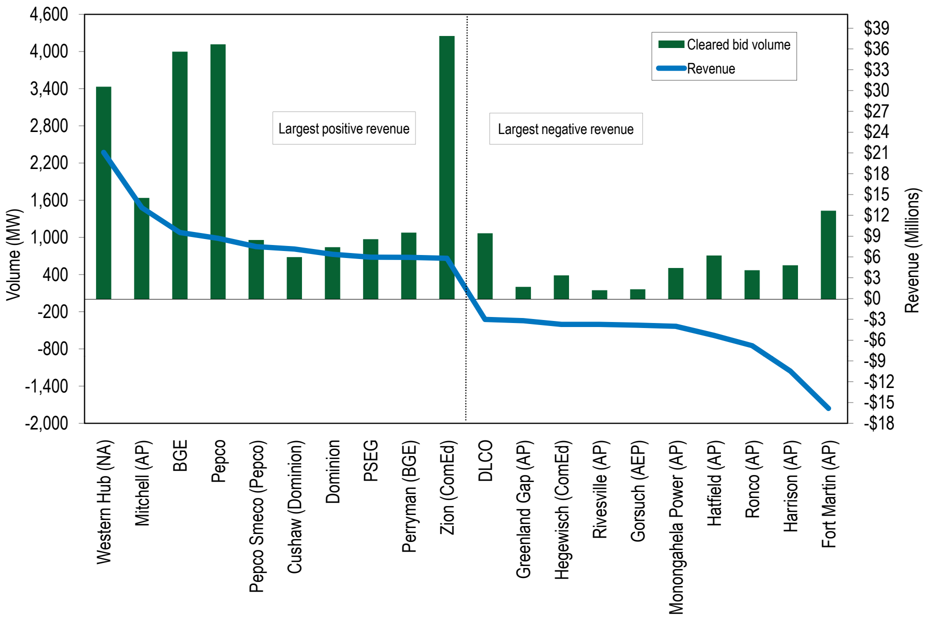


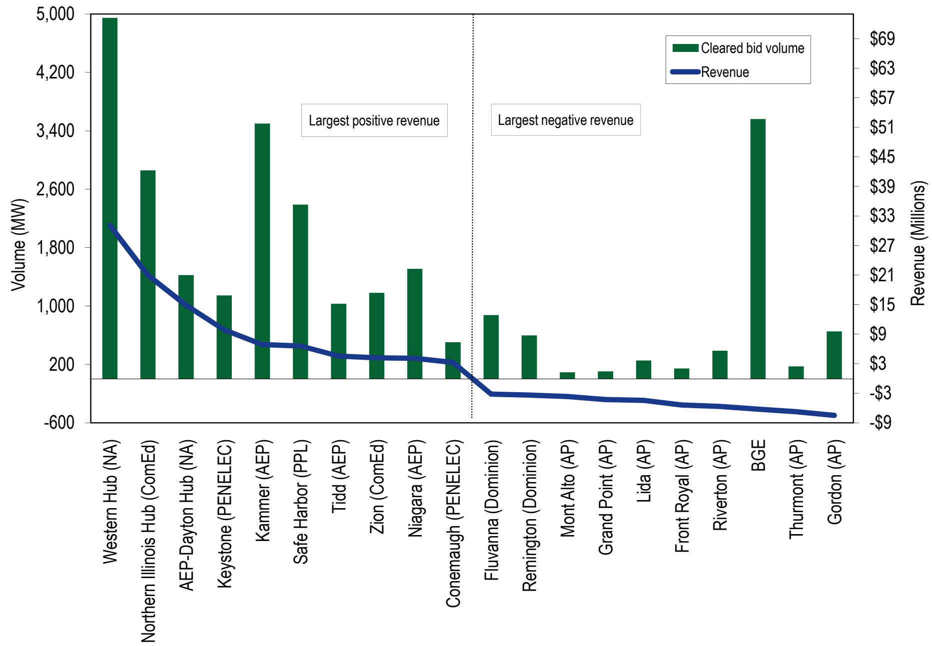
Figure 8-4 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the 2011 to 2014 Long Term FTR Auction. The top 10 positive revenue producing FTR sources accounted for $106.22 million of the total revenue of $49.80 million paid in the auction. They also comprised 9.1 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$50.59 million of revenue and constituted 3.0 percent of all FTRs bought in the auction.

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

28 The total positive revenue producing FTR sinks was $184.31 million and the total negative revenue producing FTR sinks was -$134.50 million. The overall revenue paid in the auction was $49.80 million.

29 For Figure 8-3 through Figure 8-11, each FTR sink and source that is not a control zone has its corresponding control zone listed in parentheses after its name. Most FTR sink and source control zone identifications for hubs and interface pricing points are listed as NA because they cannot be assigned to a specific control zone.

Figure 8-4 Ten largest positive and negative revenue producing FTR sources purchased in the Long Term FTR Auction: Planning periods 2011 to 2014



Annual FTR Auction Revenue

Table 8-18 shows Annual FTR Auction revenue data by trade type, hedge type, FTR direction and class type. For the 2010 to 2011 planning period, the Annual FTR Auction netted $1,049.83 million in revenue, with buyers paying $1,060.00 million and sellers receiving $10.17 million. For the 2009 to 2010 planning period, the Annual FTR Auction netted $1,329.80 million in revenue, with buyers paying $1,338.88 million and sellers receiving $9.09 million.

For the 2010 to 2011 planning period, the counter flow FTRs in the Annual FTR Auction netted -$120.97 million in revenue, with buyers receiving $125.98 million and sellers paying $5.00 million, and the prevailing flow FTRs in the Annual FTR Auction netted $1,170.80 million in revenue, with buyers paying $1,185.98 million and sellers receiving $15.18 million.

Table 8-18 Annual FTR Auction revenue: Planning period 2010 to 2011

			Class Type			
Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($31,703,144)	($48,028,679)	($43,231,947)	($122,963,770)
		Prevailing Flow	$101,156,043	$184,829,000	$172,777,067	$458,762,110
		Total	$69,452,899	$136,800,321	$129,545,120	$335,798,340
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$4,190,505	$20,643,158	$9,781,679	$34,615,342
		Total	$4,190,505	$20,643,158	$9,781,679	$34,615,342
	Total	Counter Flow	($31,703,144)	($48,028,679)	($43,231,947)	($122,963,770)
		Prevailing Flow	$105,346,548	$205,472,159	$182,558,746	$493,377,453
		Total	$73,643,404	$157,443,479	$139,326,799	$370,413,682
Self-scheduled bids	Obligations	Counter Flow	($3,013,115)	NA	NA	($3,013,115)
		Prevailing Flow	$692,601,292	NA	NA	$692,601,292
		Total	$689,588,178	NA	NA	$689,588,178
Buy and self-scheduled bids	Obligations	Counter Flow	($34,716,259)	($48,028,679)	($43,231,947)	($125,976,885)
		Prevailing Flow	$793,757,336	$184,829,000	$172,777,067	$1,151,363,403
		Total	$759,041,077	$136,800,321	$129,545,120	$1,025,386,518
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$4,190,505	$20,643,158	$9,781,679	$34,615,342
		Total	$4,190,505	$20,643,158	$9,781,679	$34,615,342
	Total	Counter Flow	($34,716,259)	($48,028,679)	($43,231,947)	($125,976,885)
		Prevailing Flow	$797,947,840	$205,472,159	$182,558,746	$1,185,978,745
		Total	$763,231,581	$157,443,479	$139,326,799	$1,060,001,860
Sell offers	Obligations	Counter Flow	($100,949)	($2,404,436)	($2,499,147)	($5,004,532)
		Prevailing Flow	$492,925	$9,363,404	$5,201,761	$15,058,090
		Total	$391,976	$6,958,967	$2,702,614	$10,053,558
	Options	Counter Flow	$0	$0	$0	$0
		Prevailing Flow	$0	$85,206	$34,159	$119,365
		Total	$0	$85,206	$34,159	$119,365
	Total	Counter Flow	($100,949)	($2,404,436)	($2,499,147)	($5,004,532)
		Prevailing Flow	$492,925	$9,448,610	$5,235,920	$15,177,455
		Total	$391,976	$7,044,173	$2,736,773	$10,172,923

Figure 8-5 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue from the Annual FTR Auction for the 2010 to 2011 planning period. The top 10 positive revenue producing FTR sinks accounted for $934.75 million (89.0 percent) of the total revenue of $1,049.83 million paid in the auction. They also comprised 33.7 percent of all FTRs bought in the auction. The sinks with the highest positive auction revenue are all control zones or large aggregates. The top 10 negative revenue producing

FTR sinks accounted for -$39.66 million of revenue and constituted 3.2 percent of all FTRs bought in the auction.

Figure 8-5 Ten largest positive and negative revenue producing FTR sinks purchased in the Annual FTR Auction: Planning period 2010 to 2011

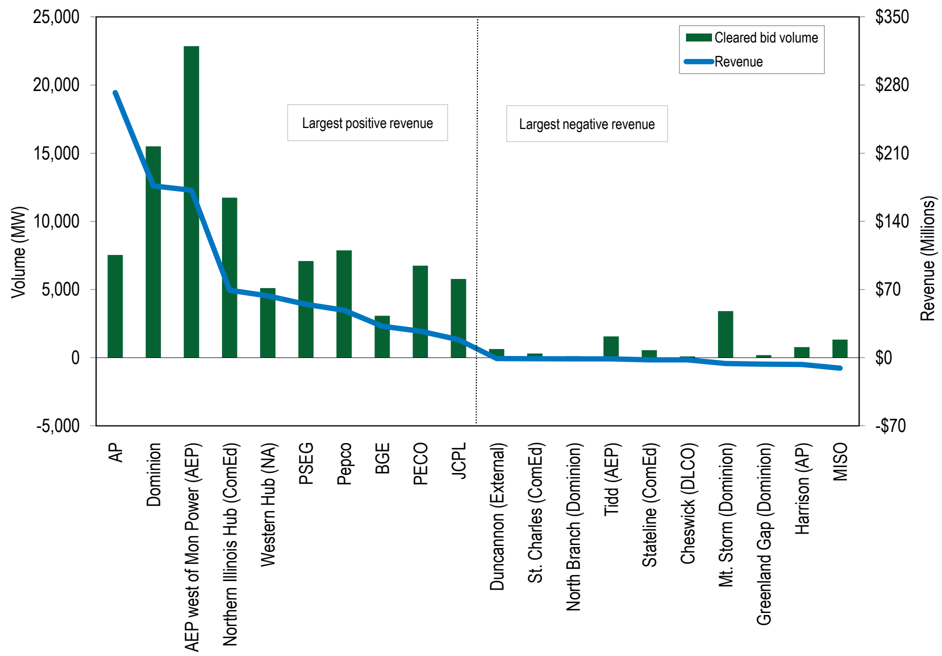
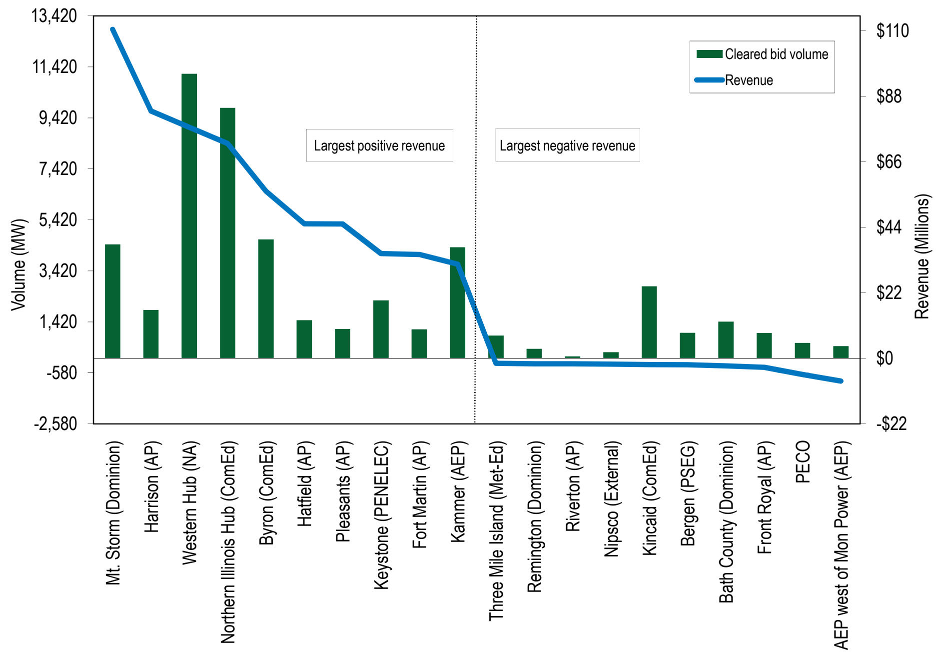


Figure 8-6 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Annual FTR Auction for the 2010 to 2011 planning period. The top 10 positive revenue producing FTR sources accounted for $591.32 million (56.3 percent) of the total revenue of $1,049.83 million paid in the auction. They also comprised 15.3 percent of all FTRs bought in the auction. The top 10 negative revenue producing FTR sources accounted for -$30.02 million of revenue and constituted 3.2 percent of all FTRs bought in the auction.

Figure 8-6 Ten largest positive and negative revenue producing FTR sources purchased in the Annual FTR Auction: Planning period 2010 to 2011



Monthly Balance of Planning Period FTR Auction Revenue

Table 8-19 shows Monthly Balance of Planning Period FTR Auction revenue data by trade type, hedge type and class type. For the 2010 to 2011 planning period through December 31, 2010, the Monthly Balance of Planning Period FTR Auctions netted $16.67 million in revenue, with buyers paying $97.53 million and sellers receiving $80.87 million. For the 2009 to 2010 planning period, the Monthly Balance of Planning Period FTR Auctions netted $19.49 million in revenue, with buyers paying $82.12 million and sellers receiving $62.63 million.

Table 8-19 Monthly Balance of Planning Period FTR Auction revenue: Calendar year 2010

			Class Type			
Monthly Auction	Hedge Type	Trade Type	24-Hour	On Peak	Off Peak	All
Jan-10	Obligations	Buy bids	($358,507)	$3,027,607	$1,763,504	$4,432,604
		Sell offers	$383,960	$1,556,699	$561,863	$2,502,522
	Options	Buy bids	$0	$341,524	$118,211	$459,735
		Sell offers	$83,413	$542,599	$261,153	$887,164
Feb-10	Obligations	Buy bids	$530,509	$2,872,273	$2,657,432	$6,060,214
		Sell offers	($116,080)	$1,524,315	$1,983,143	$3,391,378
	Options	Buy bids	$0	$241,692	$234,325	$476,018
		Sell offers	$8,606	$825,079	$709,563	$1,543,248
Mar-10	Obligations	Buy bids	($549,382)	$4,005,065	$2,109,386	$5,565,069
		Sell offers	$565,634	$1,299,894	$578,118	$2,443,646
	Options	Buy bids	$972	$27,948	$25,433	$54,353
		Sell offers	$80,862	$900,428	$434,215	$1,415,505
Apr-10	Obligations	Buy bids	($455,673)	$1,949,169	$1,914,146	$3,407,643
		Sell offers	$411,821	$303,177	$711,735	$1,426,734
	Options	Buy bids	$0	$31,664	$7,685	$39,348
		Sell offers	$397	$619,455	$222,426	$842,278
May-10	Obligations	Buy bids	($174,016)	$796,256	$742,930	$1,365,170
		Sell offers	$55,656	$98,700	$324,803	$479,159
	Options	Buy bids	$0	$38,754	$2,044	$40,798
		Sell offers	$30	$400,162	$143,440	$543,632
Jun-10	Obligations	Buy bids	$3,248,555	$8,066,567	$6,097,873	$17,412,995
		Sell offers	$953,733	$3,876,255	$3,725,334	$8,555,322
	Options	Buy bids	$5,802	$158,851	$116,761	$281,415
		Sell offers	$16,839	$4,265,630	$2,393,988	$6,676,457
Jul-10	Obligations	Buy bids	($524,716)	$8,542,586	$5,945,266	$13,963,136
		Sell offers	$6,087	$2,569,941	$1,806,154	$4,382,181
	Options	Buy bids	$17,289	$270,145	$135,568	$423,002
		Sell offers	$1,672,986	$2,791,024	$2,166,674	$6,630,683
Aug-10	Obligations	Buy bids	$1,995,876	$8,489,218	$5,226,059	$15,711,153
		Sell offers	$78,088	$6,252,007	$3,227,745	$9,557,840
	Options	Buy bids	$0	$197,801	$157,086	$354,887
		Sell offers	$30,431	$1,626,257	$1,836,640	$3,493,328
Sep-10	Obligations	Buy bids	$590,917	$6,987,726	$5,639,454	$13,218,098
		Sell offers	$135,907	$3,907,689	$2,637,138	$6,680,733
	Options	Buy bids	$0	$333,742	$312,661	$646,403
		Sell offers	$123,445	$1,921,160	$2,853,356	$4,897,961
Oct-10	Obligations	Buy bids	($249,561)	$5,623,697	$4,521,315	$9,895,451
		Sell offers	$268,353	$2,510,800	$3,344,531	$6,123,684
	Options	Buy bids	$0	$350,232	$466,829	$817,061
		Sell offers	$4,951	$1,416,747	$1,146,768	$2,568,466
Nov-10	Obligations	Buy bids	($35)	$6,554,668	$4,843,680	$11,398,312
		Sell offers	$448,438	$3,944,079	$3,535,186	$7,927,704
	Options	Buy bids	$0	$308,719	$217,288	$526,007
		Sell offers	$8,192	$1,284,796	$1,008,824	$2,301,813
Dec-10	Obligations	Buy bids	($243,480)	$7,603,208	$5,024,487	$12,384,214
		Sell offers	$3,607,375	$2,926,895	$1,961,215	$8,495,485
	Options	Buy bids	$0	$343,419	$163,999	$507,419
		Sell offers	$10,466	$1,642,922	$925,082	$2,578,471
2009/2010*	Obligations	Buy bids	($121,010)	$45,775,003	$33,593,366	$79,247,359
		Sell offers	$3,920,764	$21,760,177	$17,779,192	$43,460,133
	Options	Buy bids	$98,620	$1,940,920	$834,871	$2,874,411
		Sell offers	$263,053	$11,631,451	$7,274,458	$19,168,962
2010/2011**	Obligations	Buy bids	$4,817,556	$51,867,670	$37,298,133	$93,983,359
		Sell offers	$5,497,980	$25,987,666	$20,237,303	$51,722,948
	Options	Buy bids	$23,091	$1,962,910	$1,570,193	$3,556,193
		Sell offers	$1,867,311	$14,948,536	$12,331,333	$29,147,179

* Shows Twelve Months for 2009/2010; ** Shows seven months ended 31-Dec-2010 for 2010/2011

Figure 8-7 summarizes total revenue associated with all FTRs, regardless of source, to the FTR sinks that produced the largest positive and negative revenue in the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2010 to 2011 planning period. The top 10 positive revenue producing FTR sinks accounted for $39.76 million of revenue and 7.3 percent of all FTRs bought in the Monthly Balance of Planning Period FTR Auctions. The top 10 negative revenue producing FTR sinks accounted for -$12.55 million of revenue and constituted 0.5 percent of all FTRs bought in the auctions. The MW volume is the net of all buys and sells from the Monthly Balance of Planning Period FTR Auctions during the 2010 to 2011 planning period. The net market volume sinking at the West Interface Hub was negative since the total cleared volume of the monthly FTR buy bids sinking at the West Interface Hub was less than the total cleared volume of the monthly FTR sell offers sinking at the West Interface Hub.

Figure 8-7 Ten largest positive and negative revenue producing FTR sinks purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2010 to 2011 through December 31, 2010

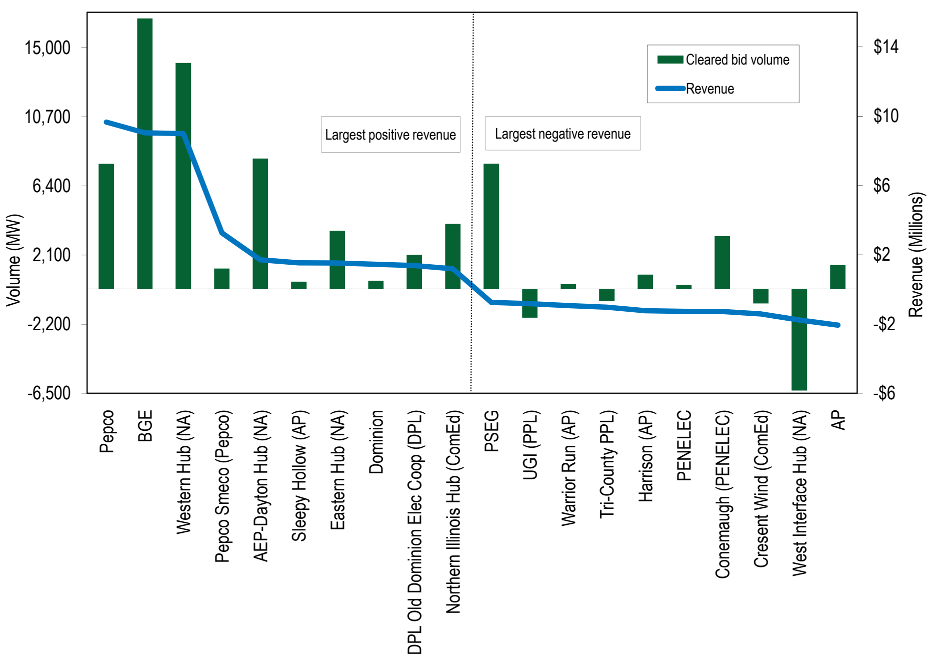
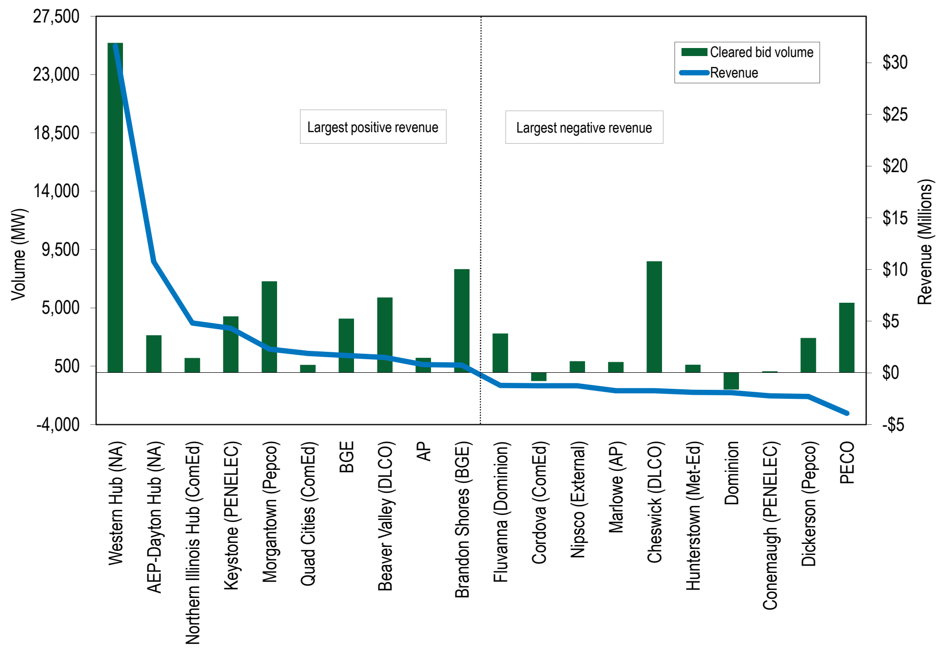


Figure 8-8 summarizes total revenue associated with all FTRs, regardless of sink, from the FTR sources that produced the largest positive and negative revenue from the Monthly Balance of Planning Period FTR Auctions during the first seven months of the 2010 to 2011 planning period. The top 10 positive revenue producing FTR sources accounted for $60.36 million and 7.6 percent of all FTRs bought in the auctions. The top 10 negative revenue producing FTR sources accounted for -$19.42 million of revenue and constituted 2.5 percent of all FTRs bought in the auctions.

Figure 8-8 Ten largest positive and negative revenue producing FTR sources purchased in the Monthly Balance of Planning Period FTR Auctions: Planning period 2010 to 2011 through December 31, 2010



Revenue Adequacy

Congestion revenue is created in an LMP system when all loads pay and all generators receive their respective LMPs. When load pays more than the amount that generators receive, excluding losses, positive congestion revenue exists and is available to cover the target allocations of FTR holders. The load MW exceed the generation MW in constrained areas because part of the load is served by imports using transmission capability into the constrained areas. Generating units that are the source of such imports are paid the price at their own bus which does not reflect congestion in constrained areas. Generation in a constrained area receives the congestion price and all load in the constrained area pays the congestion price. As a result, load congestion payments are usually greater than the congestion-related payments to generation.[30] 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.

30 For an illustration of how total congestion revenue is generated and how FTR target allocations and congestion receipts are determined, see Table 3-1, "Congestion revenue, FTR target allocations and FTR congestion credits: Illustration," *Technical Reference for PJM Markets,* Section 3 "Financial Transmission and Auction Revenue Rights. "

FTRs are paid out for each month from congestion revenues, FTR auction revenues and excess revenues carried forward from prior months and distributed back from later months. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs during the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning year. For the 2009 to 2010 planning period, FTRs were not fully funded and thus an uplift charge was collected. Table 8-20 shows the composition of FTR target allocations and FTR revenues for the 2009 to 2010 and the 2010 to 2011 planning periods, with the latter shown through December 31, 2010. FTR targets are composed of FTR target allocations and associated adjustments. Other adjustments may be made for items such as modeling changes or errors.

FTR revenues are primarily comprised of hourly congestion revenue and net negative congestion. FTR revenues also include ARR excess which is the difference between ARR target allocations and FTR auction revenues. Competing use revenues are based on the Unscheduled Transmission Service Agreement between the New York Independent System Operator (NYISO) and PJM. This agreement sets forth the terms and conditions under which compensation is provided for transmission service in connection with transactions not scheduled directly or otherwise prearranged between NYISO and PJM. Congestion revenues appearing in Table 8-20 include both congestion charges associated with PJM facilities and those associated with reciprocal, coordinated flowgates in the Midwest ISO whose operating limits are respected by PJM.[31] The operating protocol governing the wheeling contracts between Public Service Electric and Gas Company (PSE&G) and Consolidated Edison Company of New York (Con Edison) resulted in a reimbursement of $0.8 million in congestion charges to Con Edison in the 2010 to 2011 planning period through December 31, 2010.[32,33] November 2010 FTR revenue adjustments included a charge to the Day-Ahead Operating Reserves of $1.4 million. This charge was necessary because the amount of hourly net negative congestion revenues could not be offset by positive congestion revenues at the end of the month and therefore was allocated as additional Day-Ahead Operating Reserves charges during the month. This means that within an hour, the congestion dollars collected by load were less than the congestion dollars paid to generation. This is accounted for as a charge, which is allocated to Day-Ahead Operating Reserves. This type of adjustment is infrequent.

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

32 111 FERC ¶ 61,228 (2005).

33 See the *2010 State of the Market Report for PJM*, Volume II, Section 4, "Interchange Transactions," at "Con Edison and PSE&G Wheeling Contracts" and Appendix E, "Interchange Transactions" at Table E-2, "Con Edison and PSE&G wheel settlements data: Calendar year 2010."

Table 8-20 Total annual PJM FTR revenue detail (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011

Accounting Element	2009/2010	2010/2011*
ARR information		
ARR target allocations	$1,276.9	$603.5
FTR auction revenue	$1,368.7	$640.6
ARR excess	$91.9	$37.2
FTR targets		
FTR target allocations	$908.1	$1,153.4
Adjustments:		
Adjustments to FTR target allocations	($1.5)	($1.1)
Total FTR targets	$906.6	$1,152.3
FTR revenues		
ARR excess	$91.9	$37.2
Competing uses	$0.0	$0.0
Congestions		
Net Negative Congestion (enter as negative)	($37.8)	($26.1)
Hourly congestion revenue	$854.9	$997.8
Midwest ISO M2M (credit to PJM minus credit to Midwest ISO)	($31.0)	($28.3)
Consolidated Edison Company of New York and Public Service Electric and Gas Company Wheel (CEPSW) congestion credit to Con Edison (enter as negative)	($2.0)	($0.8)
Adjustments:		
Excess revenues carried forward into future months	$27.3	$0.0
Excess revenues distributed back to previous months	$9.2	$1.8
Other adjustments to FTR revenues	$2.4	$0.1
Total FTR revenues	$923.5	$981.8
Excess revenues distributed to other months	($45.1)	($1.8)
Net Negative Congestion charged to DA Operating Reserves	$0.0	$1.4
Excess revenues distributed to CEPSW for end-of-year distribution	$0.0	$0.0
Excess revenues distributed to FTR holders	$0.0	$0.0
Total FTR congestion credits	$878.4	$981.4
Total congestion credits on bill (includes CEPSW and end-of-year distribution)	$880.3	$982.2
Remaining deficiency	$28.3	$170.9

* Shows seven months ended 31-Dec-10

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 compensate FTR holders fully for congestion on those specific paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations. Table 8-21 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month. At the end of the 12-month planning period, excess congestion charges are used to offset any monthly congestion credit deficiencies.

The total row in Table 8-21 is not the simple sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues carried back from later months. For example, August 2009 FTR revenues are shown as $90.0 million, which includes revenues from congestion charges for the month, excess revenues carried forward from prior months ($12.8 million) and excess revenues carried back from later months ($4.5 million). For the 2009 to 2010 planning period, the total FTR revenues and FTR credits were $878.4 million which was $28.3 million deficient of the total FTR Target Allocations. For the first seven months of the 2010 to 2011 planning period, there is a credit deficiency of $170.9 million to the $1,152.0 million in FTR target allocations.

Table 8-21 Monthly FTR accounting summary (Dollars (Millions)): Planning periods 2008 to 2009 and 2009 to 2010

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Excess/Deficiency (with adjustments)
Jun-09	$54.6	$43.9	100.0%	$43.9	100.0%	$0.0
Jul-09	$53.2	$40.4	100.0%	$40.4	100.0%	$0.0
Aug-09	$92.4	$92.4	81.3%	$92.4	100.0%	$0.0
Sep-09	$31.4	$31.4	87.4%	$31.4	100.0%	$0.0
Oct-09	$57.8	$57.8	83.4%	$57.8	100.0%	$0.0
Nov-09	$38.2	$37.9	100.0%	$37.9	100.0%	$0.0
Dec-09	$101.9	$93.7	100.0%	$93.7	100.0%	$0.0
Jan-10	$223.7	$213.0	100.0%	$213.0	100.0%	$0.0
Feb-10	$113.3	$111.0	100.0%	$111.0	100.0%	$0.0
Mar-10	$29.0	$35.8	73.9%	$29.0	81.1%	($6.8)
Apr-10	$47.7	$68.5	69.3%	$47.7	69.7%	($20.8)
May-10	$80.2	$80.9	99.1%	$80.2	99.1%	($0.7)
Summary for Planning Period 2009 to 2010						
Total	$878.4	$906.6		$878.4	96.9%	($28.3)
Jun-10	$193.9	$196.1	97.8%	$193.9	98.9%	($2.2)
Jul-10	$274.8	$273.0	100.0%	$273.0	100.0%	$0.0
Aug-10	$111.1	$119.2	93.2%	$111.1	93.2%	($8.1)
Sep-10	$116.0	$165.3	70.0%	$116.0	70.2%	($49.2)
Oct-10	$52.2	$67.4	77.4%	$52.2	77.5%	($15.1)
Nov-10	$51.1	$80.0	61.9%	$51.1	63.9%	($28.9)
Dec-10	$184.1	$251.5	73.2%	$184.1	73.2%	($67.4)
Summary for Planning Period 2010 to 2011 through December 31, 2010						
Total	$981.4	$1,152.3		$981.4	85.2%	($170.9)

Figure 8-9 shows the FTR payout ratio by month from June 2003 through December 2010. The monthly percentages include the distribution of excess congestion charges. The monthly FTR payout ratio for the months in the 2010 to 2011 planning period may change if excess congestion charges are collected in the remainder of the planning period. November 2010 has the lowest monthly payout ratio of 62 percent since June 2003. The data in Figure 8-9 begins at June 1, 2003, when PJM replaced the allocation of FTRs with an allocation of ARRs and an associated Annual FTR Auction.

Figure 8-9 FTR payout ratio by month: June 2003 to December 2010[34]

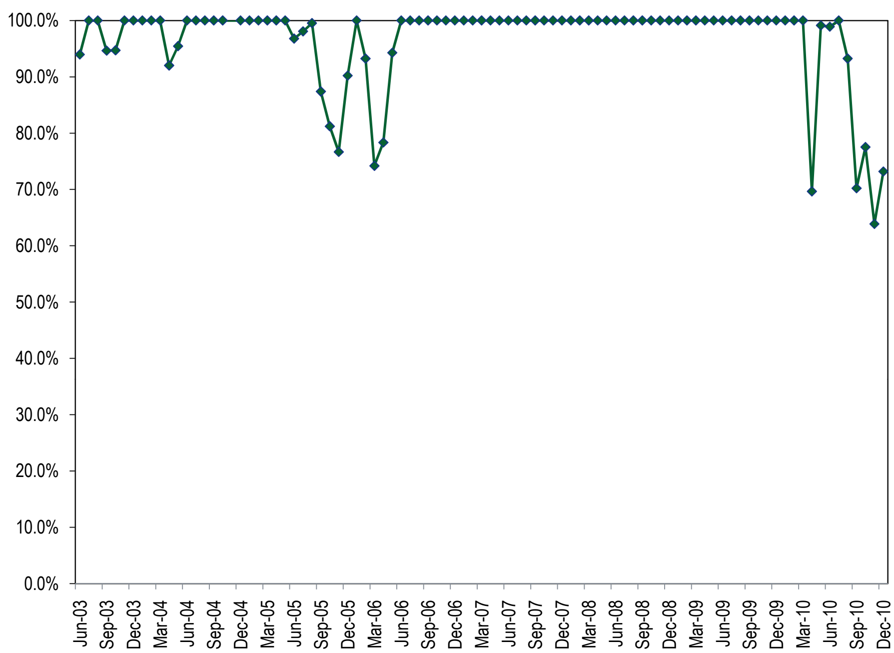


Table 8-22 shows the FTR payout ratio by planning period. FTRs were paid at 96.9 percent of the target allocation level for the 2009 to 2010 planning period and were paid at 85.2 percent of the target allocation level for the 2010 to 2011 planning period through December 31, 2010.

Table 8-22 FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011*	85.2%

* through December 31, 2010

34 The underlying data for Figure 8-9 and Table 8-22 is from the "FTR Credit" spreadsheet posted on PJM's website at <http://www.pjm.com/markets-and-operations/ftr/revenue-adequacy.aspx>.

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 2010 to 2011 planning period through December 31, 2010. Figure 8-10 shows the FTR sinks with the largest positive and negative target allocations. The top 10 sinks that produced a financial benefit accounted for 33.8 percent of total positive target allocations during the first seven months of the 2010 to 2011 planning period. FTRs with the AP Control Zone as the sink included 9.3 percent of all positive target allocations. The sinks with the highest positive target allocations are all control zones or large aggregates. The top 10 sinks that created liability accounted for 13.8 percent of total negative target allocations. FTRs with the Western Hub as the sink encompassed 2.8 percent of all negative target allocations.

Figure 8-10 Ten largest positive and negative FTR target allocations summed by sink: Planning period 2010 to 2011 through December 31, 2010

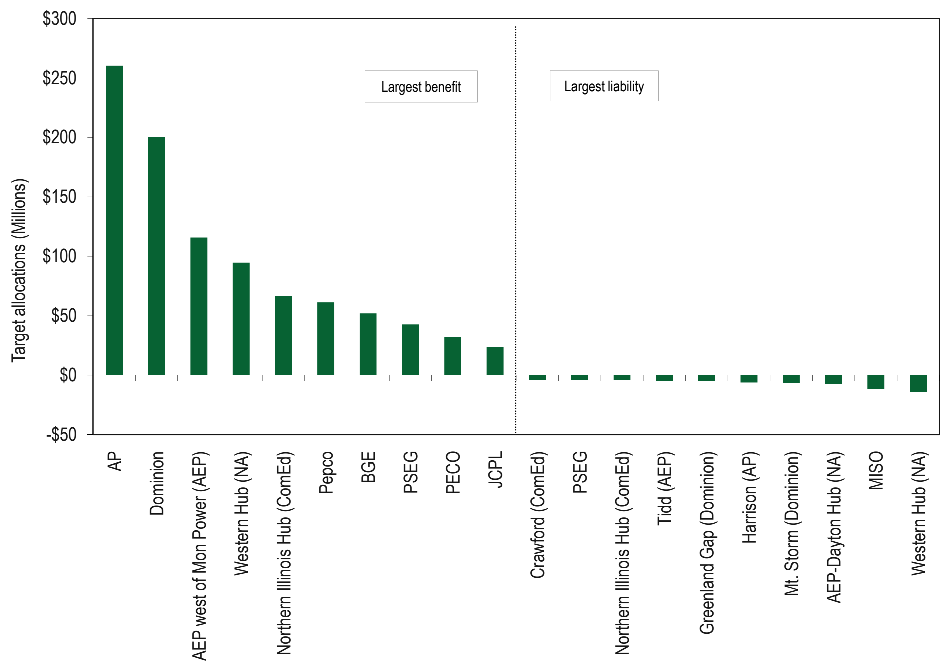
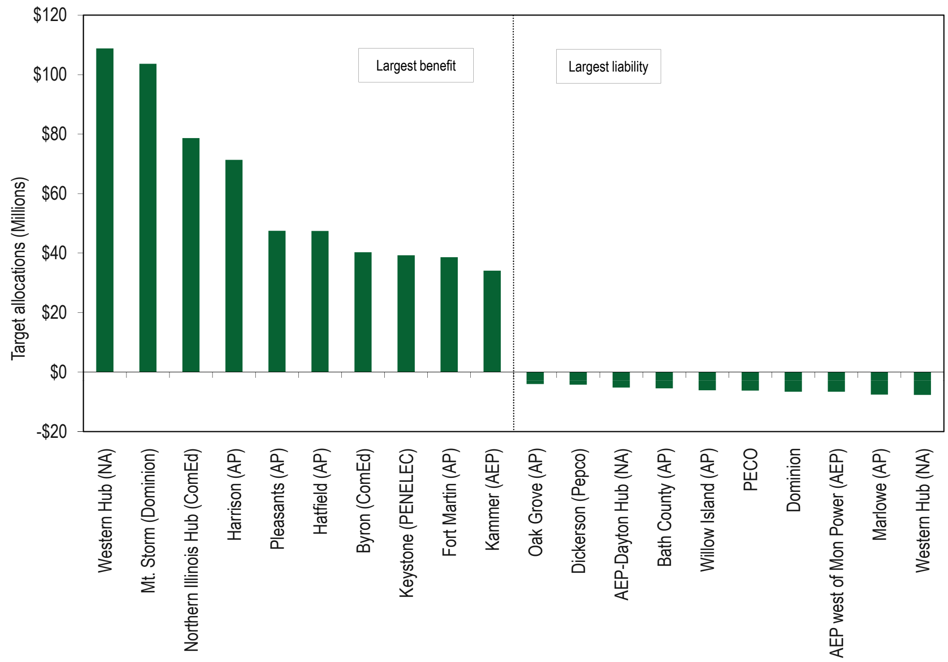


Figure 8-11 shows the FTR sources with the largest positive and negative target allocations during the first seven months of the 2010 to 2011 planning period. The top 10 sources with a positive target allocation accounted for 21.8 percent of total positive target allocations. FTRs with the Western Hub as their source included 3.9 percent of all positive target allocations. The top 10 sources with a negative target allocation accounted for 12.0 percent of total negative target allocations. FTRs with the Western Hub as the source encompassed 1.5 percent of all negative target allocations.

Figure 8-11 Ten largest positive and negative FTR target allocations summed by source: Planning period 2010 to 2011 through December 31, 2010



Profitability

FTR profitability is the difference between the revenue received for an FTR and the cost of the FTR. For a prevailing flow FTR, the FTR credits represent the revenue that an FTR holder should receive and the auction price paid represents the cost. For a counter flow FTR, the auction price represents the revenue that an FTR holder receives and the FTR credits represent the cost. The cost of self scheduled FTRs is zero. ARR holders that self schedule FTRs purchase the FTRs in the Annual FTR Auction but ARR holders receive ARR credits that equal the purchase price of the FTRs. Table 8-23 lists FTR profits by organization type and FTR direction for the 2010 calendar year. FTR profits are the sum of the daily FTR credits minus the daily FTR auction costs for each FTR held by an organization. FTR credits are the product of the FTR target allocations and the FTR payout ratio for the respective planning period. The FTR payout ratio was 96.9 percent of the target allocation for the 2009 to 2010 planning period and 85.2 percent for the first seven months of the 2010 to 2011 planning period. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source in the Day-Ahead Energy Market. The FTR credits do not include after the fact adjustments. The daily FTR auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in days. The results indicate the total FTR profits in 2010 were $138.7 million for financial entities and $909.6 million for physical entities. Self scheduled FTRs account for a large portion of the FTR profits of physical entities.

Table 8-23 FTR profits by organization type and FTR direction: Calendar year 2010

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	$884,347,111	$25,203,961	$909,551,072
Financial	$72,482,324	$66,229,890	$138,712,214
Total	$956,829,435	$91,433,851	$1,048,263,286

Table 8-24 lists the monthly FTR profits in 2010 calendar year by organization type. FTR profits were positive and larger in magnitude during the winter and summer months when congestion tended to be higher. The three most profitable months for FTRs were July, December and January. FTR profits decrease during the shoulder months when congestion is less.

Table 8-24 Monthly FTR profits by organization type: Calendar year 2010

	Organization Type		
Month	Physical	Financial	Total
Jan	$171,049,354	($1,214,796)	$169,834,558
Feb	$73,488,400	$972,526	$74,460,927
Mar	($77,576)	($2,155,466)	($2,233,042)
Apr	$27,429,595	$3,747,527	$31,177,122
May	$37,696,949	$4,273,858	$41,970,807
Jun	$112,263,355	$21,073,562	$133,336,918
Jul	$142,003,516	$54,182,662	$196,186,178
Aug	$58,797,492	$7,018,763	$65,816,255
Sep	$83,007,153	$22,306,544	$105,313,697
Oct	$23,554,381	($2,044,975)	$21,509,405
Nov	$30,044,673	$4,095,797	$34,140,470
Dec	$150,293,779	$26,456,212	$176,749,991
Total	$909,551,072	$138,712,214	$1,048,263,286

Auction Revenue Rights

FTRs and ARRs are both financial instruments that entitle the holder to receive revenues or to pay charges based on nodal price differences. FTRs provide holders with revenues or charges based on the locational congestion price differences actually experienced in the Day-Ahead Energy Market while ARRs are financial instruments that entitle their holders to receive revenue or to pay charges based on prices determined in the Annual FTR Auction.[35] These price differences are based on the bid prices of participants in the Annual FTR Auction which relate to their expectations about the level of congestion in the Day-Ahead Energy Market. The auction clears the set of feasible

35 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.

FTR bids which produce the highest net revenue. In other words, ARR revenues are a function of FTR auction participants' expectations of locational congestion price differences in the Day-Ahead Energy Market.

ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between sink and source from the Annual FTR Auction. An ARR value can be positive or negative depending on the sink-minus-source price difference, with a negative difference resulting in a liability for the holder. The ARR target allocation represents the revenue that an ARR holder should receive. All ARR holders receive ARR credits equal to their target allocations if total net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than, or equal to, the sum of all ARR target allocations. ARR credits can be positive or negative and can range from zero to the ARR target allocation. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are less than that, available revenue is proportionally allocated among all ARR holders.

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

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

Market Structure

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

Supply

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

ARR Allocation

For the 2007 to 2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[36] Long Term ARRs can give LSEs the ability to hedge their congestion costs on a long-term basis by providing price certainty throughout the 10 planning period time frame. Long Term ARR holders can opt out of any planning period during the 10 planning period timeline and self schedule their Long Term ARRs as FTRs.

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

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

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

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

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[37] Participants may seek additional ARRs in the Stage 2 allocation.

36 See the *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.
37 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 21.

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

When ARRs are allocated, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM utilizes a power flow model of security-constrained dispatch that takes into account generation and transmission facility outages and is based on reasonable assumptions about the configuration and availability of transmission capability during the planning period.[38] This simultaneous feasibility requirement is necessary to ensure that there are sufficient revenues from transmission congestion charges to satisfy all resulting ARR obligations, thereby preventing underfunding of the ARR obligations for a given planning period. If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints:

Equation 8-1 Calculation of prorated ARRs

Individual prorated MW = (Constraint capability) • (Individual requested MW / Total requested MW) • (1 / MW effect on line).[39]

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

Residual ARRs

On June 19, 2007, PJM submitted to the FERC revisions to the OATT to include a new type of ARR known as a residual ARR.[40] On August 13, 2007, the FERC issued an order accepting the revisions to the PJM OATT with an effective date of August 20, 2007.[41] Only ARR holders that had their Stage 1A or Stage 1B ARRs prorated are eligible to receive residual ARRs. Residual ARRs would be available if additional transmission system capability were added during the planning period after the annual ARR allocation. This additional transmission system capability would not have been accounted for in the initial annual ARR allocation, but it enables the creation of residual ARRs. Residual ARRs would be effective on the first day of the month in which the additional

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

39 See the *Technical Reference for PJM Markets,* Section 3, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail.

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

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

transmission system capability is included in FTR auctions and would exist until the end of the planning period. For the following planning period, any residual ARRs would be available as ARRs in the annual ARR allocation process as they would be included in the power flow model. The amount of a residual ARR would be the difference between the ARR holder's Stage 1A or Stage 1B request and their actual prorated Stage 1A or Stage 1B ARR MW. Stage 1 ARR holders have a priority right to ARRs and those holders who had ARRs prorated because of the simultaneous feasibility requirement previously had no recourse from the impact of proration. Residual ARRs are a separate product from incremental ARRs. No residual ARRs have been allocated to date.

Incremental ARRs

Market participants constructing generation interconnection or transmission expansion projects may request an allocation of incremental ARRs consistent with the project's increased transmission capability.[42] Incremental ARRs are available in a three-round allocation process with a single point-to-point combination requested and one-third of the incremental ARR MW allocated in each round. Incremental ARRs can be accepted or refused after rounds one and two. If accepted, that ARR is removed from availability in subsequent rounds; if it is refused, that ARR is available in the next rounds. Such incremental ARRs are effective for the lesser of 30 years or the life of the facility or upgrade. At any time during this 30-year period, in place of continuing this 30-year ARR, the participant has a single opportunity to replace the allocated ARRs with a right to request ARRs during the annual ARR allocation process between the same source and sink. Such participants can also permanently relinquish their incremental ARRs at any time during the life of the ARRs as long as overall the system simultaneous feasibility can be maintained.

Table 8-25 lists the incremental ARR allocation volume for the 2008 to 2009, 2009 to 2010 and the 2010 to 2011 planning periods. For the 2010 to 2011 planning period, there were bids for 531 MW and 100 percent of the bids were cleared. For the 2009 to 2010 planning period, there were bids for 531 MW and 100 percent of the bids were cleared.

Table 8-25 Incremental ARR allocation volume: Planning periods 2008 to 2009, 2009 to 2010 and 2010 to 2011

Planning Period	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2008/2009	15	891	891	100%	0	0%
2009/2010	14	531	531	100%	0	0%
2010/2011	14	531	531	100%	0	0%

Incremental ARRs (IARRs) for RTEP Upgrades

IARRs are allocated to Responsible Customers that have been assigned cost responsibility for upgrades included in the PJM's Regional Transmission Expansion Plan (RTEP) that are for a Regional Facility (at or above 500 kV) or a Necessary Lower Voltage Facility (Regionally Assigned Facilities). Responsible Customers as defined in Schedule 12 of the Tariff are network service

42 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), p. 30.

customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each Regionally Assigned Facility and allocates the IARRs, if any are created by the upgrade, to eligible Responsible Customers based on their percentage of cost responsibility. The Responsible Customer may choose to decline the IARR allocation during the annual ARR allocation process.[43] Each network service customer within a zone is allocated a share of the IARRs identified in each zone based on their percentage share of the network service peak load of the zone. For the annual ARR allocation for the 2010/2011 planning period, 203.6 MWs of IARRs were allocated for RTEP upgrades. Table 8-26 lists the one RTEP upgrade project that was allocated IARRs.

Table 8-26 IARRs allocated for 2010 to 2011 Annual ARR Allocation for RTEP upgrades[44]

		IARR Parameters		
Project #	Project Description	Source	Sink	Total MW
B0287	Install 600 MVAR Dynamic Reactive Device at Elroy 500kV	RTEP B0287 Source	DPL	203.6

Table 8-27 lists the top 10 principal binding constraints, along with their corresponding control zones in order of severity that limited supply in the annual ARR allocation for the 2010 to 2011 planning period. The order of severity is determined by the violation degree of the binding constraint as computed in the simultaneous feasibility test.[45] The violation degree is a measure of the MW that a constraint is over the limit for a type of facility; a higher number indicates a more severe constraint.

Table 8-27 Top 10 principal binding transmission constraints limiting the annual ARR allocation: Planning period 2010 to 2011

Constraint	Type	Control Zone
AP South	Interface	AP
Electric Junction - Nelson	Line	ComEd
State Line - Wolf Lake	Line	Midwest ISO
Cedar Grove - Clifton	Line	PSEG
Roseland - Whippany	Line	PSEG
Brandon Shores - Riverside	Line	BGE
Waterman - West Dekalb	Line	ComEd
Linden - North Ave	Line	PSEG
Bayonne - PVSC	Line	PSEG
Cumberland - Juniata	Line	PPL

Demand

PJM's OATT specifies the types of transmission services that are available to eligible customers. Eligible customers submit requests to PJM for network and firm, point-to-point transmission service

43 PJM. "Manual 6: Financial Transmission Rights," Revision 12 (July 1, 2009), pp. 31 and "IARRs for RTEP Upgrades Allocated for 2010/2011 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2010-2011/iarrs-rtep-upgrades-allocated-for-2010-11-planning-period.ashx>.

44 RTEP B0287 Source is a new aggregate comprised of an equal ten percent weighting of the following ten pnodes: MUDDYRN 13 KV Unit1, MUDDYRN 13 KV Unit2, MUDDYRN 13 KV Unit3, MUDDYRN 13 KV Unit4, MUDDYRN 13 KV Unit5, MUDDYRN 13 KV Unit6, MUDDYRN 13 KV Unit7, MUDDYRN 13 KV Unit8, PEACHBOT 22 KV UNIT02 and PEACHBOT 22 KV UNIT03.

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

through the PJM Open Access Same-Time Information System (OASIS). ARRs associated with firm transmission service that spans the entire next planning period, outside of the annual ARR allocation window, can also be requested through the PJM OASIS.[46] PJM evaluates each transmission service request for its impact on the system and approves or denies the request accordingly. All approved transmission services can be accommodated by the PJM transmission system. Theoretically, since total eligible ARR demand for the system cannot exceed the combined MW of network and firm, point-to-point transmission service, ARR supply should equal ARR demand if ARR nominations are consistent with the historic use of the transmission system. However, the demand for some ARRs could be left unmet if the same resources are nominated as ARR source points by multiple parties for delivery across shared paths and the result exceeds the stated capability of the transmission system to deliver from those sources to load. The combination might not be simultaneously feasible. When the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints.

ARR Reassignment for Retail Load Switching

Current PJM rules provide that when load switches among LSEs during the planning period, a proportional share of associated ARRs that sink into a given control or load aggregation zone is automatically reassigned to follow that load.[47] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value to that control zone. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and any MW of load may be reassigned multiple times over a planning period. Residual ARRs are also subject to the rules of ARR reassignment. This practice supports competition by ensuring that the hedge against congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, these underlying self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may diminish the value of the hedge.

The MMU recommends that when load switches among LSEs during the planning period, a proportional share of the underlying self scheduled FTRs follow the load in the same manner that ARRs do. ARRs are assigned to firm transmission service customers because these customers pay the costs of the transmission system that enables firm energy delivery. At the time of the FTR Annual Auction, ARR holders have the ability to acquire FTRs by choosing to self schedule in the annual FTR auction. When load switches among LSEs during the planning period, the LSE gaining load is reassigned its proportional share of the ARRs from the LSE losing load. After the Annual FTR Auction has occurred, the LSE gaining load does not have the ability to self schedule FTRs associated with the reassigned ARRs. The self scheduled FTRs are obtained as the direct result of the ARR assignment and should therefore follow the reassignment of ARRs when load switches in order to ensure that the new LSE is in the same competitive position as the LSE that lost load.

Table 8-28 summarizes ARR MW and associated revenue automatically reassigned for network load in each control zone where changes occurred between June 2009 and December 2010.

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

About 17,831 MW of ARRs associated with $269,600 per MW-day of revenue were automatically reassigned in the first seven months of the 2010 to 2011 planning period. About 19,061 MW of ARRs with $362,400 per MW-day of revenue were reassigned for the entire 12-month 2009 to 2010 planning period.

Table 8-28 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 1, 2009, through December 31, 2010

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2009/2010 (12 months)	2010/2011 (7 months)*	2009/2010 (12 months)	2010/2011 (7 months)*
AECO	417	620	$7.6	$4.7
AEP	268	381	$6.3	$9.1
AP	629	906	$76.9	$101.0
BGE	3,162	2,707	$63.2	$41.2
ComEd	3,145	1,976	$10.1	$48.1
DAY	21	93	$0.1	$0.4
DLCO	371	233	$1.0	$1.8
Dominion	0	0	$0.0	$0.0
DPL	952	768	$10.9	$7.5
JCPL	1,151	1,818	$19.3	$19.3
Met-Ed	33	388	$0.8	$6.1
PECO	29	652	$0.5	$5.3
PENELEC	8	310	$0.2	$5.8
Pepco	2,511	1,874	$25.5	$21.6
PPL	4,489	2,279	$103.7	$37.8
PSEG	1,984	2,715	$49.6	$44.9
RECO	62	111	$0.0	$0.1
Total	19,230	17,831	$375.8	$354.5

* Through 31-Dec-10

Market Performance

Volume

Table 8-29 lists the annual ARR allocation volume by stage and round for the 2009 to 2010 and the 2010 to 2011 planning periods. For the 2010 to 2011 planning period, there were 61,793 MW (45.6 percent of total demand) bid in Stage 1A, 27,850 MW (20.5 percent of total demand) bid in Stage 1B and 45,971 MW (33.9 percent of total demand) bid in Stage 2. Of 135,614 MW in total ARR requests, 61,793 MW were allocated in Stage 1A and 27,850 MW were allocated in Stage 1B while 12,200 MW were allocated in Stage 2 for a total of 101,843 MW (75.1 percent) allocated. Eligible market participants subsequently converted 55,732 MW of these allocated ARRs into Annual FTRs (54.7 percent of total allocated ARRs), leaving 46,111 MW of ARRs outstanding. For the 2009 to 2010 planning period, there had been 64,987 MW (46.4 percent of total demand) bid in Stage 1A, 26,517 MW (18.9 percent of total demand) bid in Stage 1B and 48,533 MW (34.7 percent of total demand) bid in Stage 2. Of 140,037 MW in total ARR requests, 64,913 MW were allocated in Stage 1A and 26,514 MW were allocated in Stage 1B while 17,986 MW were allocated in Stage 2 for a total of 109,413 MW (78.1 percent) allocated. There were 68,589 MW or 62.7 percent of the allocated ARRs converted into FTRs. ARR holders did not relinquish any ARRs for the 2010 to 2011 planning period. In comparison, for the 2009 to 2010 planning period, ARR holders relinquished 2.9 MW of the allocated Stage 1B ARRs. The uncleared volume in Table 8-29 includes ARRs that were relinquished.

Table 8-29 Annual ARR allocation volume: Planning periods 2009 to 2010 and 2010 to 2011

Planning Period	Stage	Round	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
2009/2010	1A	0	7,527	64,987	64,913	99.9%	74	0.1%
	1B	1	3,582	26,517	26,514	100.0%	3	0.0%
	2	2	1,580	16,521	5,680	34.4%	10,841	65.6%
		3	1,157	16,413	6,013	36.6%	10,400	63.4%
		4	994	15,599	6,293	40.3%	9,306	59.7%
		Total	3,731	48,533	17,986	37.1%	30,547	62.9%
	Total		14,840	140,037	109,413	78.1%	30,624	21.9%
2010/2011	1A	0	8,862	61,793	61,793	100.0%	0	0.0%
	1B	1	3,885	27,850	27,850	100.0%	0	0.0%
	2	2	1,901	15,333	4,161	27.1%	11,172	72.9%
		3	1,374	15,321	4,167	27.2%	11,154	72.8%
		4	1,247	15,317	3,872	25.3%	11,445	74.7%
		Total	4,522	45,971	12,200	26.5%	33,771	73.5%
	Total		17,269	135,614	101,843	75.1%	33,771	24.9%

Revenue

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

Revenue Adequacy

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

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

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

ARR holders will receive $1,028.8 million in credits from the Annual FTR Auction during the 2010 to 2011 planning period, with an average hourly ARR credit of $1.15 per MWh. During the comparable 2009 to 2010 planning period, ARR holders received $1,273.5 million in ARR credits, with an average hourly ARR credit of $1.33 per MWh.

Table 8-30 lists ARR target allocations and net revenue sources from the Annual and Monthly Balance of Planning Period FTR Auctions for the 2009 to 2010 and the 2010 to 2011 (through December 31, 2010) planning periods. Annual FTR Auction net revenue has been sufficient to cover ARR target allocations for both planning periods. The 2010 to 2011 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $38.1 million in auction net revenue through December 31, 2010, above the amount needed to pay 100 percent of ARR target allocations. The entire 2009 to 2010 planning period's Annual and Monthly Balance of Planning Period FTR Auctions generated a surplus of $75.8 million in auction net revenue, above the amount needed to pay 100 percent of ARR target allocations.

Table 8-30 ARR revenue adequacy (Dollars (Millions)): Planning periods 2009 to 2010 and 2010 to 2011

	2009/2010	2010/2011
Total FTR auction net revenue	$1,349.3	$1,066.9
Annual FTR Auction net revenue	$1,329.8	$1,050.1
Monthly Balance of Planning Period FTR Auction net revenue*	$19.5	$16.8
ARR target allocations	$1,273.5	$1,028.8
ARR credits	$1,273.5	$1,028.8
Surplus auction revenue	$75.8	$38.1
ARR payout ratio	100%	100%
FTR payout ratio*	96.9%	85.2%

* Shows twelve months for 2009/2010 and seven months ended 31-Dec-10 for 2010/2011

ARR Proration

During the annual ARR allocation process, all ARRs must be simultaneously feasible to ensure that the physical transmission system can support the approved set of ARRs. If all the ARR requests made during the annual ARR allocation process are not feasible, then ARRs are prorated and allocated in proportion to the MW level requested and in inverse proportion to the effect on the binding constraints.[48,49]

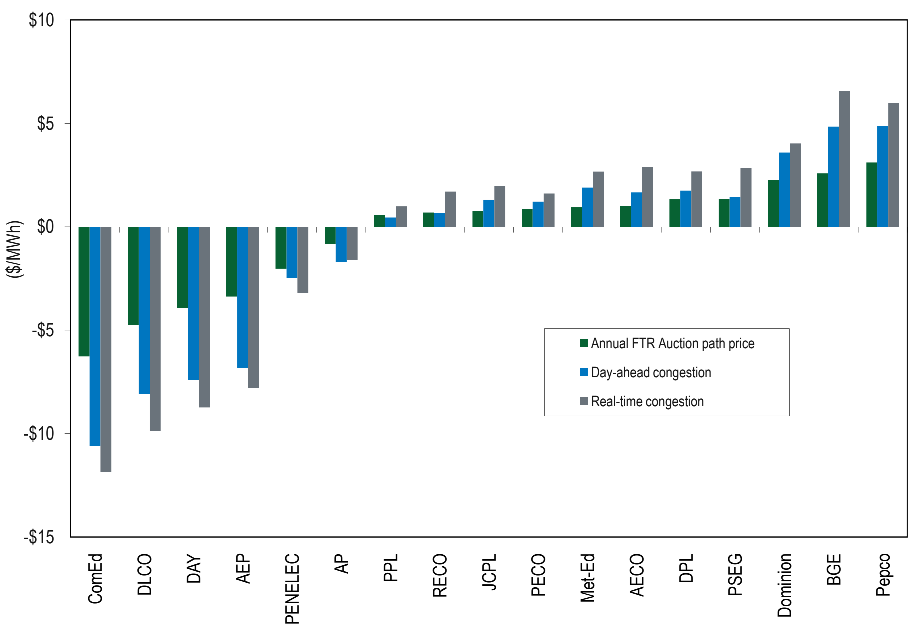
When ARRs were allocated for the 2010 to 2011 planning period, some of the requested ARRs were prorated in Stage 2 in order to ensure simultaneous feasibility. No ARRs were prorated in Stage 1A and Stage 1B since there were no constraints affecting the ARR allocation in these two stages.

ARR and FTR Revenue and Congestion

FTR Prices and Zonal Price Differences

As an illustration of the relationship between FTRs and congestion, Figure 8-12 shows Annual FTR Auction prices and an approximate measure of day-ahead and real-time congestion for each PJM control zone for the 2010 to 2011 planning period through December 31, 2010. The day-ahead and real-time congestion are based on the difference between zonal congestion prices and Western Hub congestion prices. The figure shows, for example, that an FTR from the Western Hub to the PECO Control Zone cost $0.87 per MWh in the Annual FTR Auction and that about $1.21 per MWh of day-ahead congestion and $1.60 per MWh of real-time congestion existed between the Western Hub and the PECO Control Zone. The data shows that congestion costs, approximated in this way, were positive for most control zones located east of the Western Hub while congestion costs were negative and were more negative than the price of FTRs for control zones that are located west of that Hub.

Figure 8-12 Annual FTR Auction prices vs. average day-ahead and real-time congestion for all control zones relative to the Western Hub: Planning period 2010 to 2011 through December 31, 2010



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

49 See the *Technical Reference for PJM Markets,* Section 3, "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining the ARR prorating method.

Effectiveness of ARRs as a Hedge against Congestion

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

The comparison between the revenue received by ARR holders and the actual congestion experienced by these ARR holders in the Day-Ahead Energy Market and the balancing energy market is presented by control zone in Table 8-31. ARRs and self scheduled FTRs that sink at an aggregate are assigned to a control zone if applicable.[50] Total revenue equals the ARR credits and the FTR credits from ARRs which are self scheduled as FTRs. The ARR credits do not include the credits for the portion of any ARR that was self scheduled as an FTR since ARR holders purchase self scheduled FTRs in the Annual FTR Auction and that revenue is then paid back to the ARR holders, netting the transaction to zero. ARR credits are calculated as the product of the ARR MW (excludes any self scheduled FTR MW) and the sink-minus-source price difference for the ARR path from the Annual FTR Auction.

FTR credits equal FTR target allocations adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and the congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are paid to FTR holders and, depending on market conditions, may be less than the target allocation. The FTR payout ratio equals the percentage of the target allocation that FTR holders actually receive as credits. The FTR payout ratio was 96.9 percent of the target allocation for the 2009 to 2010 planning period.

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

Data shown are for the 2009 to 2010 planning period summed by ARR control zone sink. For example, the table shows that for the 2009 to 2010 planning period, ARRs allocated to the AECO Control Zone received a total of $16.9 million in revenue which was the sum of $16.3 million in ARR credits and $0.6 million in credits for self scheduled FTRs. This total revenue was $1.0 million less than the congestion costs of $17.9 million from the Day-Ahead Energy Market and the balancing energy market incurred by organizations in the AECO Control Zone that held ARRs or self scheduled FTRs.

50 For Table 8-31 through Table 8-33, aggregates are separated into their individual bus components and each bus is assigned to a control zone. The “PJM” Control Zone does not include all the buses in PJM, but does include all aggregate sinks that are external to PJM or buses that cannot otherwise be assigned to a specific control zone.

Table 8-31 ARR and self scheduled FTR congestion hedging by control zone: Planning period 2009 to 2010

Control Zone	ARR Credits	Self-Scheduled FTR Credits	Total Revenue	Congestion	Total Revenue - Congestion Difference	Percent Hedged
AECO	$16,334,067	$594,669	$16,928,736	$17,916,307	($987,571)	94.5%
AEP	$4,284,698	$144,069,787	$148,354,485	$148,207,387	$147,098	>100%
AP	$45,451,856	$183,064,919	$228,516,775	$45,556,651	$182,960,124	>100%
BGE	$46,459,694	$2,847,697	$49,307,391	$19,446,235	$29,861,156	>100%
ComEd	$14,549,758	$30,963,973	$45,513,731	$80,554,940	($35,041,208)	56.5%
DAY	$6,207,117	$801,013	$7,008,130	$16,300,765	($9,292,635)	43.0%
DLCO	$2,450,918	$1,801	$2,452,719	$25,131,767	($22,679,048)	9.8%
Dominion	$6,134,065	$145,819,810	$151,953,875	$14,763,373	$137,190,503	>100%
DPL	$17,061,417	$799,792	$17,861,209	$32,381,921	($14,520,712)	55.2%
JCPL	$28,119,166	$954,861	$29,074,027	$23,686,835	$5,387,191	>100%
Met-Ed	$108,900	$11,784,177	$11,893,077	$19,927,580	($8,034,502)	59.7%
PECO	$1,932,121	$18,391,851	$20,323,972	($24,109,589)	$44,433,561	>100%
PENELEC	$22,966,832	$12,204,795	$35,171,627	$23,223,101	$11,948,527	>100%
Pepco	$21,798,040	$1,724,179	$23,522,219	$119,615,249	($96,093,030)	19.7%
PJM	$7,727,385	($153,147)	$7,574,238	$9,260,327	($1,686,090)	81.8%
PPL	$1,102,352	$14,750,503	$15,852,855	($25,146,383)	$40,999,238	>100%
PSEG	$83,906,675	$3,078,677	$86,985,352	$4,067,059	$82,918,293	>100%
RECO	($41,455)	$0	($41,455)	$1,429,306	($1,470,761)	0.0%
Total	$326,553,606	$571,699,358	$898,252,964	$552,212,831	$346,040,133	>100%

During the 2009 to 2010 planning period, congestion costs associated with the 109,612 MW of allocated ARRs were $552.2 million. As Table 8-10 indicates, 68,589 MW of ARRs were converted into FTRs through the self scheduling option, with 41,023 MW remaining as ARRs. The 41,023 MW of remaining ARRs provided $326.6 million of ARR credits, while the self scheduled FTRs provided $571.7 million of revenue. Total congestion was fully hedged by the combination of ARRs and self scheduled FTRs (Table 8-31). The effectiveness of ARRs as a hedge depends on the ARR value which is a function of the FTR auction prices, on FTR values for self scheduled FTRs, on congestion patterns in the Day-Ahead Energy Markets, and on the FTR payout ratio.

Effectiveness of ARRs and FTRs as a Hedge against Congestion

Table 8-32 compares the revenue for ARR and FTR holders and the congestion in both the Day-Ahead Energy Market and the balancing energy market for the 2009 to 2010 planning period. This compares the total hedge provided by all ARRs and all FTRs to the total congestion costs within each control zone. ARRs and FTRs that sink at an aggregate or a bus are assigned to a control zone if applicable. ARR credits are calculated as the product of the ARR MW and the price difference (sink minus source) for the ARR path from the Annual FTR Auction. The “FTR Credits” column represents the total FTR target allocation for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any FTRs that were self scheduled from ARRs, adjusted by the FTR payout ratio. The FTR target allocation is equal to the product of the FTR MW and congestion price differences between sink and source that occur in the Day-Ahead Energy Market. FTR credits are the product of the FTR target allocations and the FTR payout ratio. The FTR payout ratio was 96.9 percent of the target allocation for the 2009 to 2010 planning period. The “FTR Auction Revenue” column shows the amount paid for FTRs that sink in each control zone from the applicable FTRs from the Long Term FTR Auction, the Annual FTR Auction, the Monthly Balance of Planning Period FTR Auctions and any ARRs that were self scheduled as FTRs. ARR holders that self schedule FTRs purchased the FTRs in the Annual FTR Auction and that revenue was then paid back to those ARR holders through ARR credits on a monthly basis throughout the planning period, ultimately netting the transaction to zero. The total ARR and FTR hedge is the sum of the ARR credits and the FTR credits minus the FTR auction revenue. The “Congestion” column shows the total amount of congestion in the Day-Ahead Energy Market and the balancing energy market in each control zone. The last column shows the difference between the total ARR and FTR hedge and the congestion cost for each control zone.

The results indicate that the value of ARRs and FTRs together hedged 96.2 percent of total congestion costs. During the 2009 to 2010 planning period, the 109,413 MW of cleared ARRs produced $1,274.6 million of ARR credits while the total of all FTR credits was $879.8 million. Together, the ARR credits and FTR credits provided $2,154.4 million in total revenue. When calculating the total ARR and FTR hedge, the cost to obtain the FTRs must be subtracted from the total ARR and FTR revenue. This cost is the sum of the FTR auction revenues, which was $1,368.7 million for the 2009 to 2010 planning period. The total ARR and FTR value equals $785.7 million, which is less than the $817.0 million of congestion in the Day-Ahead Energy Market and the balancing energy market. For example, the table shows that all ARRs and FTRs that sink in the AP Control Zone received $365.0 million in ARR credits and $185.8 million in FTR credits. After subtracting the cost of the FTRs, the FTR auction revenue of $324.1 million, the total ARR and FTR hedge was $226.7 million. The total value of the ARRs and FTRs was $93.7 million higher than the $133.0 million of congestion in the Day-Ahead Energy Market and the balancing energy market.

Table 8-32 ARR and FTR congestion hedging by control zone: Planning period 2009 to 2010

Control Zone	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
AECO	$19,253,322	$4,219,721	$25,540,714	($2,067,671)	$10,817,043	($12,884,714)	0.0%
AEP	$223,262,229	$157,919,018	$214,898,039	$166,283,208	$101,031,029	$65,252,179	>100%
AP	$365,048,488	$185,774,650	$324,136,428	$226,686,710	$132,996,453	$93,690,257	>100%
BGE	$52,131,739	$29,778,076	$34,611,142	$47,298,673	$40,787,754	$6,510,919	>100%
ComEd	$27,261,279	$61,701,901	$12,504,362	$76,458,818	$192,953,092	($116,494,274)	39.6%
DAY	$7,505,314	$1,208,852	($146,827)	$8,860,993	$7,993,310	$867,683	>100%
DLCO	$2,454,337	$10,773,597	($3,631,769)	$16,859,703	$25,084,077	($8,224,374)	67.2%
Dominion	$213,840,239	$156,718,198	$240,575,877	$129,982,560	$150,288,685	($20,306,125)	86.5%
DPL	$18,915,429	$13,281,446	$38,621,277	($6,424,402)	$28,398,375	($34,822,777)	0.0%
JCPL	$34,924,192	($890,074)	$44,362,866	($10,328,748)	$18,958,788	($29,287,536)	0.0%
Met-Ed	$27,312,021	$15,468,233	$35,876,903	$6,903,351	$4,609,666	$2,293,685	>100%
PECO	$49,863,646	$21,467,430	$56,377,913	$14,953,163	($22,617,637)	$37,570,800	>100%
PENELEC	$49,412,326	$61,808,839	$63,892,689	$47,328,476	$58,884,119	($11,555,643)	80.4%
Pepco	$23,702,306	$111,232,601	$102,336,490	$32,598,417	$66,040,760	($33,442,343)	49.4%
PJM	$9,979,482	($4,934,756)	($3,846,501)	$8,891,227	$8,551,453	$339,774	>100%
PPL	$55,143,860	$21,032,754	$65,711,467	$10,465,147	($8,203,127)	$18,668,274	>100%
PSEG	$94,609,270	$34,463,423	$119,797,997	$9,274,696	($1,140,092)	$10,414,788	>100%
RECO	($41,455)	($1,186,779)	($2,875,400)	$1,647,166	$1,562,712	$84,454	>100%
Total	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%

Table 8-33 shows that for the 2009 to 2010 planning period, the total value of the ARR and FTR positions was $31.3 million less than the total congestion within PJM. All ARRs and FTRs hedged 96.2 percent of the total congestion costs in the Day-Ahead Energy Market and the balancing energy market within PJM. For the first seven months of the 2010 to 2011 planning period, the FTR payout ratio was 85.2 percent of the target allocation. All ARRs and FTRs covered 78.7 percent of the total congestion costs within PJM for the first seven months of the 2010 to 2011 planning period. The total value of the ARR and FTR positions was less than the cost of congestion by $207.7 million.

Table 8-33 ARR and FTR congestion hedging: Planning periods 2009 to 2010 and 2010 to 2011[51]

Planning Period	ARR Credits	FTR Credits	FTR Auction Revenue	Total ARR and FTR Hedge	Congestion	Total Hedge - Congestion Difference	Percent Hedged
2009/2010	$1,274,578,024	$879,837,129	$1,368,743,667	$785,671,486	$816,996,460	($31,324,974)	96.2%
2010/2011*	$603,465,391	$804,051,163	$640,632,851	$766,883,703	$974,618,985	($207,735,282)	78.7%

* Shows seven months ended 31-Dec-10

51 The FTR credits do not include after-the-fact adjustments. For the 2010 to 2011 planning period, the ARR credits were the total credits allocated to all ARR holders for the first seven months (June through December 2010) of this planning period, and the FTR Auction Revenue includes the net revenue in the Monthly Balance of Planning Period FTR Auctions for the first seven months of this planning period and the portion of Annual FTR Auction revenue distributed to the first seven months.

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

The hedge provided by ARRs and FTRs can also be measured by comparing the value of the ARRs and FTRs that sink in a zone to the cost of real time energy in the zone. This is a direct measure of the net price of energy rather than a comparison of the ARR/FTR credits to an accounting measure of congestion. This measures the value of the hedge against real time energy costs provided by ARRs and FTRs purchased for this period. Table 8-34 shows the total value of ARRs received by those who pay for the transmission system plus the total value of FTRs received by those who purchased FTRs in the FTR auctions. The combined ARR plus FTR credits covers the largest percentage of total energy charges in the AP Control Zone (16.8 percent), and the lowest percentage of total energy charges in the RECO Control Zone (0.7 percent).

Table 8-34 ARRs and FTRs as a hedge against energy charges by control zone: Calendar year 2010

Control Zone	ARR Related Hedge (Including Self-Scheduled FTRs)	FTR Hedge (Excluding Self-Scheduled FTRs)	Total ARR and FTR Hedge	Total Energy Charges	Percent of Energy Charges Covered by ARR and FTR Credits
AECO	$11,331,731	($1,253,200)	$10,078,531	$648,843,903	1.6%
AEP	$197,171,258	$19,086,147	$216,257,405	$5,446,688,183	4.0%
AP	$374,775,181	$1,694,199	$376,469,380	$2,236,317,432	16.8%
BGE	$41,961,361	$34,967,124	$76,928,485	$2,028,384,691	3.8%
ComEd	$70,826,510	$29,508,528	$100,335,037	$3,654,271,600	2.7%
DAY	$7,144,529	($27,716)	$7,116,813	$690,554,201	1.0%
DLCO	$3,976,605	$17,232,438	$21,209,043	$583,038,268	3.6%
Dominion	$247,160,002	$21,337,739	$268,497,741	$5,445,331,798	4.9%
DPL	$15,793,341	$1,609,810	$17,403,150	$1,063,993,554	1.6%
JCPL	$24,705,469	($678,592)	$24,026,877	$1,340,425,345	1.8%
Met-Ed	$15,378,117	$11,053,779	$26,431,896	$818,645,514	3.2%
PECO	$37,079,205	$5,585,082	$42,664,287	$2,257,763,964	1.9%
PENELEC	$30,547,049	$36,419,581	$66,966,631	$791,735,853	8.5%
Pepco	$23,617,240	$39,947,933	$63,565,173	$1,898,879,568	3.3%
PJM	$17,311,724	$413,799	$17,725,523	NA	NA
PPL	$25,599,188	($253,197)	$25,345,991	$2,113,296,887	1.2%
PSEG	$63,669,715	($9,370,259)	$54,299,456	$2,562,025,594	2.1%
RECO	$37,522	$589,661	$627,183	$84,770,663	0.7%
Total	$1,208,085,747	$207,862,855	$1,415,948,602	$33,717,296,942	4.2%