FTR Revenue Stakeholder Report

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1. Introduction

PJM has experienced shortfalls in Financial Transmission Right (FTR) funding over the last several years. Complex factors affect the underfunding of FTRs, and PJM has been working diligently with its stakeholders to address the underfunding problem. On December 28, 2011, in Docket No. EL12-19-000, FirstEnergy Solutions Corp. and Allegheny Energy Supply Company, LLC (collectively, FirstEnergy Companies) filed a complaint with the Federal Energy Regulatory Commission (Commission) seeking an order requiring PJM to modify certain provisions of Schedule 1 (Schedule 1) of the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C. (Operating Agreement), as well as the parallel provisions of the Attachment K – Appendix of the PJM Open Access Transmission Tariff (Tariff),[1] that govern the funding of FTRs. In response to the complaint, PJM committed to producing a report detailing the causes of the recent FTR underfunding. On March 2, 2012, the Commission issued an order dismissing the complaint "without prejudice in light of the absence of sufficient evidence as to the root cause of the FTR underfunding and PJM"s commitment to develop a comprehensive report detailing the circumstances that resulted in the FTR underfunding for stakeholder review and discussion."[2] This report fulfills PJM"s commitment in that case. The recommendations and potential solutions of PJM and its Independent Market Monitoring Unit (IMM) for resolving the underfunding problem are set forth in two separate documents posted by PJM on its web site at http://pjm.com/documents/reports.aspx.

2. Executive Summary

As a Regional Transmission Organization (RTO), PJM is responsible for maintaining the reliability of the bulk power transmission system, operating fair, efficient and non-discriminatory electricity markets, and conducting long-term infrastructure planning. Specific to the markets for FTRs, PJM"s objectives are to both ensure full

[1] Schedule 1 of the Operating Agreement and Attachment K-Appendix of the Tariff are identical. For convenience, where PJM refers only to Schedule 1 of the Operating Agreement, such references are intended to encompass the corresponding provisions of Attachment K-Appendix of the Tariff, and vice versa.

[2] *FirstEnergy Solutions Corp., Allegheny Energy Supply Company, LLC v. PJM Interconnection, L.L.C.*, 138 FERC ¶ 61,158 (2012), *reh'g pending* ("March 2 Order").[3] Capitalized terms used and not otherwise defined herein have the meaning set forth in the PJM Operating Agreement, PJM Tariff, Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (RAA) and PJM Manuals.

funding of FTRs while at the same time maximizing the use of the transmission system through allocation of Auction Revenue Rights (ARRs) and FTRs. While it is PJM‟s goal to achieve full funding, full funding of FTRs is not a mandatory requirement. The FTR product was never designed to be a full hedge of congestion and FTR full funding has never been a guarantee. FTR funding levels over the 2010/2011 and 2011/2012 Planning Periods have been approximately 85%, and from the 2006/2007 through 2009/2010 Planning Periods funding levels were greater than 95%. The FTR funding decline has revealed itself primarily in the form negative balancing congestion. The decline in FTR funding is due to the combination of an increased contribution to total PJM congestion from facilities along the PJM borders and an overall reduction in system capability due to facility outages and de-rations. The congestion along the PJM borders has accounted for approximately 54% of underfunding in 2011 whereas the reduced capability has accounted for the remaining 46%. In 2010 the congestion along the PJM borders accounted for approximately 32% of underfunding whereas the reduced capability accounted for the remaining 68%.

Historically, while underfunding and negative balancing congestion has occurred on facilities near the PJM borders, sufficient system capability existed within the PJM Region such that excess funding on constraints further away from the borders was sufficient to cover the inadequacies observed on constraints near the border. The increase in congestion along the PJM borders is directly related to the increase in quantity of market to market flowgates on the system and more specifically the implications of flowgates being added mid-Planning Period that could not be modeled in the Annual ARR and FTR feasibility analyses. Congestion along the PJM borders is more likely to result in negative balancing real-time congestion because of factors such as unpredictable external flow patterns, real-time wind resource output not being offered in the PJM Day-ahead Energy Market, external control area transmission system topology changes for which PJM does not have forward information, and unforeseen external transmission outages.

The more recent reduction in system capability that is negatively affecting revenue adequacy on constraints further from the borders can be attributed to an increase in the number of transmission outages and facility rating reductions. Transmission outages increased 15% from 2010 to 2011, and by 21% for the summer season when the system is already limited. By the end of 2012 the number of transmission outages in PJM is expected to be 35% higher than the number of transmission outages experienced in 2008. The quantity of facility rating reductions have increased by over 400% since 2005 which has also contributed to reduced system capability. This reduction in system capability creates an added strain on the system and removes margin which could offset the impacts of FTR underfunding from negative balancing congestion at the PJM borders. PJM has seen negative balancing congestion in the past but the market has historically had enough margin, less utilized capability, and excess funding to offset this negative balancing congestion. Over the last few years this excess margin has not been available due to the reductions in system capability represented by facility outages and de-rations. Specific details and examples of the recent causes of underfunding are provided in this report.

There are several potential solutions that could reduce FTR underfunding and these solutions are provided in a separate document entitled "PJM Options to address FTR Underfunding" which PJM has posted on its website at http://pjm.com/documents/reports.aspx.

The evolution of the PJM FTR market, along with the uncertainties associated with areas external to PJM but which affect PJM"s transmission system, seem to suggest that a market rule change to remove the balancing real-time congestion dollars from the FTR funding mechanism may be in order. PJM believes that removal of balancing real-time congestion achieves a more fair and balanced approach to allocating the costs to all Market Participants in the PJM Real-time Energy Market, and, consequently preserves the integrity of the FTR product. PJM is concerned that by continuing to allow the negative balancing congestion to erode the value of the FTR product, PJM will be unable to fulfill in a holistic manner its obligation to ensure the development and operation of market mechanisms to manage congestion. PJM further believes that if the balancing real-time congestion dollars were to remain part of the FTR funding mechanism, PJM should have the ability to reduce the number of allocated annual ARRs and corresponding FTRs.

Under the current Tariff and Operating Agreement, PJM cannot reduce Stage 1A ARRs. As a result, when constraints that would otherwise cause a reduction in the allocation of these rights arise, there will be an over-allocation of the number of ARRs, which in turn creates the potential for FTR revenue inadequacy. PJM can more appropriately model the risk of the congestion along the PJM borders as well as the reduced system capability if the initial allocated rights can be reduced to the point at which they are feasible. This risk is of less concern if balancing real-time congestion is not part of the FTR funding mechanism. In addition, PJM continues to work through the Regional Transmission Expansion Planning (RTEP) process to initiate transmission upgrades to ensure the future feasibility of long-term rights. Finally, PJM has made, and continues to make, improvements to its processes, and has taken steps to better coordinate its operations with its neighboring entities. PJM believes that these efforts, specifically where they are concentrated along the PJM borders, will assist in reducing FTR underfunding.

3. Background

A. Auction Revenue Rights/Financial Transmission Rights Products

(1) Overview

PJM is one of several Independent System Operators (ISOs) and RTOs that provide transmission service and operate markets for energy and/or capacity. While the ISOs and RTOs have similar market designs, none is exactly the same. PJM‟s energy markets are designed to reflect the principle of Locational Marginal Pricing (LMP).[3] LMP is the hourly integrated market clearing marginal price for energy at the location the energy is delivered or received, calculated as specified in Section 2 of Schedule 1 of the Operating Agreement. An LMP at a particular point on the transmission grid has three components: the marginal cost of energy, marginal cost of losses and marginal cost of congestion.[4] Congestion occurs when the least costly resources that are available to serve demand in a given area cannot be dispatched to meet this demand because of physical limitations of the transmission facilities located between the source point (sending end/generator) and the sink point (receiving end/load location). In the PJM LMP-based markets, the price of electricity varies by location, often significantly, as transmission constraints arise. Such constraints limit the ability of electricity to move from point A to point B, which requires PJM, as the system operator, to dispatch higher cost resources to meet demand at point B, resulting in a higher price at point B, relative to point A (*i.e.*, congestion). These price differences result in transmission congestion charges, which are assessed on all energy deliveries.

At the inception of the PJM energy markets, load serving entities (LSEs) required a mechanism by which to manage congestion costs due to the ever-changing nature of flows on the grid. Congestion costs affect LSEs‟ ability to obtain price certainty associated with their purchases of power to serve their service obligations. Therefore, in 1998, along with the implementation of the LMP markets, PJM also implemented a mechanism by which to allocate FTRs to LSEs, and subsequently developed monthly auctions for FTRs. Later, pursuant to FERC Order No. 681, PJM created long-term auctions for FTRs to protect Transmission Customers from increased costs due to transmission congestion charges.[5] FTRs are financially-settled products that Market Participants use to hedge against the cost of congestion. In essence, the FTR is part of the purchase of firm transmission service in the organized markets.

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[3] Capitalized terms used and not otherwise defined herein have the meaning set forth in the PJM Operating Agreement, PJM Tariff, Reliability Assurance Agreement Among Load Serving Entities in the PJM Region (RAA) and PJM Manuals.

[4] PJM Tariff, Attachment K – Appendix § 2.6.

[5] For many years, the FTR mechanism in PJM was comprised of monthly and annual products. In 2006, FERC issued an order expanding PJM‟s FTR mechanism to include a three-year product. *Long-Term Firm Transmission Rights in Organized Electric Markets*, Order No. 681, FERC Stats. & Regs. ¶ 31,226 (2006), *reh'g denied*, Order No. 681-A, 117 FERC ¶ 61,201 (2006).

ARRs are financial entitlements (not physical ownership) that are (1) linked to PJM‟s FTR product, and (2) allocated annually to PJM‟s network and Firm Point-to-Point Transmission Service customers in consideration of their payment of firm transmission tariff rates.[6] ARRs determine the allocation of revenue resulting from FTR Auctions; however, ARRs may also be converted into FTRs at the option of the Market Participant, as further discussed below.

FTRs and ARRs are governed by Section 7 of Schedule 1 of the PJM Operating Agreement.

(2) Financial Transmission Rights (FTRs)

FTRs are financially-settled instruments that entitle (or obligate) the holder to a stream of revenues (or charges) based on the hourly congestion price differences across a specific transmission path in the PJM Day-ahead Energy Market. Each FTR is defined from a source point (sending end/generator) to a sink point (receiving end/customer site) on the transmission grid. The value of an FTR is based upon the difference between the Day-ahead Congestion Price at the specific source and sink points on the transmission system. For each hour in which congestion exists on the transmission system between the source and sink points specified in the FTR, the holder of the FTR receives a credit (or charge) calculated as the Day-ahead Congestion Price at the sink location minus the Day-ahead Congestion Price at the source times the megawatt (MW) quantity of the FTR held.

FTRs are awarded to the most economic bidders in a multi-product FTR Auction according to a linear software optimization program that evaluates PJM‟s actual system capacity in order to maximize bid-based revenue.[7] The quantity of FTRs that PJM can auction to Market Participants is limited by the actual physical capabilities of the transmission system. Market Participants may buy and sell FTRs in the form of monthly, annual, and three year products. FTR Auctions are non-public and are limited to PJM Members and transmission customers that are able to satisfy certain credit requirements.

This process does not match individual buyers and sellers or create any contract rights or obligations between buyers and sellers, but is customized in terms of source/sink points and transmission capability within the limits of the PJM transmission

[6] Network Transmission Service is defined in the PJM Tariff as “transmission service provided pursuant to the rates, terms and conditions set forth in Part III of the PJM Tariff, or transmission service comparable to such service that is provided to a Load Serving Entity that is also a Transmission Owner.” Firm Point-to-Point Transmission Service is defined in the PJM Tariff as “Transmission Service under ... [the PJM] Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.”

[7] See PJM Tariff, Attachment K-Appendix § 7.2.1. The linear software optimization program is part of the simultaneous feasibility determination process, as discussed further below.

system. FTR Auction bids only become binding when cleared through the auction process. The value of an FTR is based upon the difference between Day-ahead Congestion Prices at two locations on the same transmission system.

PJM also maintains a bulletin board that allows Market Participants to bilaterally trade existing FTRs by way of a secondary market. The bilateral transactions may be reported to PJM via the bulletin board implemented in PJM‟s eFTR system.[8] If a report is made and a subsequent transferee can establish suitable credit with PJM, ownership of an FTR will automatically be transferred by PJM to the subsequent transferee and the Market Participants‟ billing will be adjusted accordingly.

The four market mechanisms through which Market participants can acquire FTRs are:

- *Long Term FTR Auction.* PJM conducts an annual, three-round auction for the selling and buying of Long Term FTRs. This auction takes place *before* the Annual FTR Auction, discussed below. The FTR product bought and sold in the Long Term FTR Auction is for the three consecutive planning years immediately following the current planning year[9]. The first round is held in the month of June, the second round is held in the month of September, and the third round is held in the month of December. Each round occurs prior to the start of the three planning year term covered by the relevant Long Term Auction. The capacity offered for sale in the Long Term FTR Auction is the residual system capability available after the modeling of the current planning period Annual ARR allocations. One third of the total FTR capability available in the Long Term FTR Auction is offered in each round.

- *Annual FTR Auction.* Each year, PJM conducts a multi-round annual FTR auction. The Annual FTR Auction offers for sale the entire transmission entitlement that is available on the PJM system for the entire planning year term minus entitlements consumed by previously awarded Long Term FTRs.

- *Monthly Balance of Planning Period (BoPP) FTR Auction.* PJM conducts a monthly auction to sell FTRs. The Monthly BoPP FTR Auction offers for sale any residual transmission entitlement that is available for the remainder of the Planning Period after FTRs are awarded from the Annual FTR Auction and Long Term FTR Auction.

- *Secondary Market.* The FTR secondary market is the bilateral market, as discussed above, that facilitates trading of *existing* FTRs between PJM market participants.

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[8] eFTR is one of PJM‟s eTools, which are a group of internet-based software applications that give PJM‟s market participants access to a continuous flow of real-time energy data that enables them to make business decisions and manage their transactions.
[9] A "planning year" is defined as the 12-month period beginning on June 1st and ending on May 31st of the following calendar year.

Congestion charges are the primary source used to fund FTR Target Allocations. If sufficient congestion charges are collected from the Day-ahead and Real-time Energy Markets to satisfy FTR Target Allocations, then FTRs will be fully funded. Excess congestion charges are used first, respectively, to cover any deficiencies in FTR Target Allocations within the relevant month, and to cover any deficiencies in FTR Target Allocations within the relevant Planning Period. To the extent there are any remaining year-end excess congestion charges, these will be applied to cover any deficiencies in ARR Target Allocations from previous months within the relevant Planning Period. Any remaining year-end excess congestion charges will be distributed to FTR participants on a pro-rata basis to total FTR Target Allocations.[10]

If insufficient congestion charges are collected from the Day-ahead and Real-time Energy Markets to satisfy FTR Target Allocations, then FTR credits are prorated proportionately on a pro-rata basis to FTR Target Allocations. FTR Target Allocation deficiencies are first funded from excess congestion charges from current month and subsequent months. To the extent that there are any remaining uncovered year-end FTR Target Allocation deficiencies after application of the monthly excess congestion charges, then an uplift charge is assessed to all FTR holders on a pro-rata basis according to total Target Allocations for all FTRs held at any time during the planning period.[11]

(a) Specific characteristics of FTRs

An FTR can represent either a right or an obligation to the Market Participant holding the FTR.

An FTR that provides a right to a stream of revenues to the holder is described as a "prevailing flow" FTR. The holder of a prevailing flow FTR is afforded the right to revenue based on the value of congestion across a defined pathway. Therefore, the holder of a prevailing flow FTR has the ability to deliver electricity hedged against the risk that the delivered price of electricity at the sink point of the pathway might be higher than the price at the source point of the pathway.[12] A prevailing flow FTR typically has a positive financial outcome for the holder.

[10] *See* PJM Presentation, *FTR Revenue and Modeling*, to the FTRTF (April 26, 2011), available at http://www.pjm.com/~/media/committees-groups/task-forces/ftrtf/20110426/20110426-item-04-ftr-revenue-and-modeling.ashx ("PJM April 26 Presentation").

[11] *Id*.

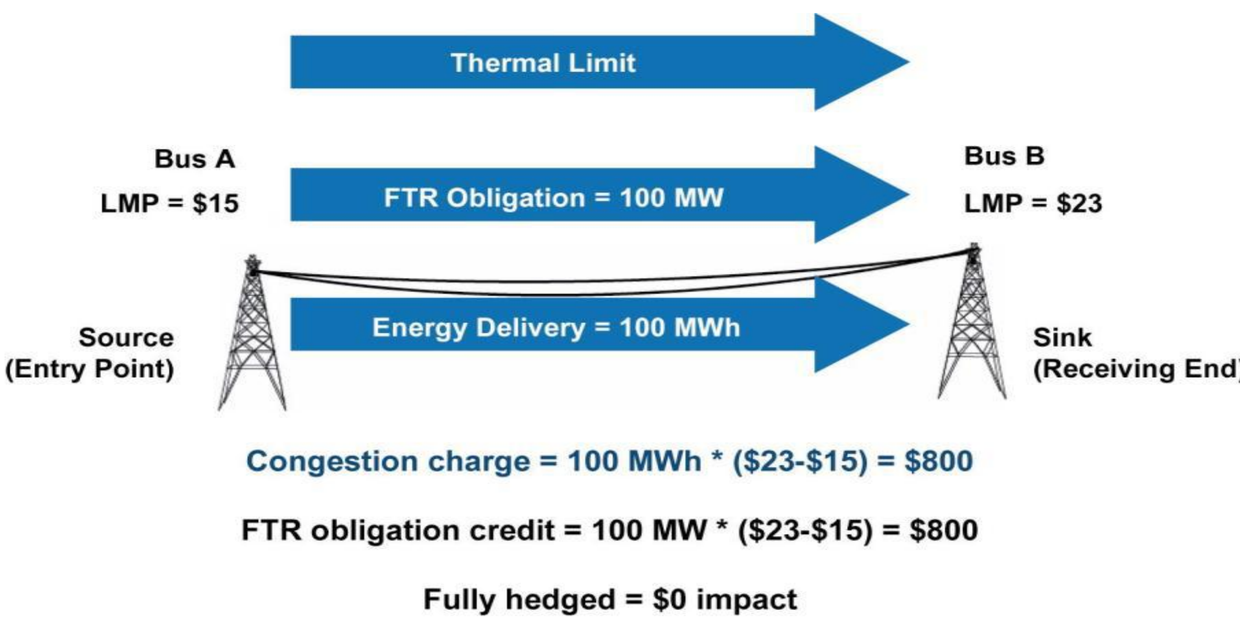
[12] Prevailing flow FTRs are finite and the number available is largely dependent on PJM"s modeling of the expected transfer capability of the transmission system. On occasion, usually due to unforeseen events, including unscheduled transmission transactions (i.e., "loop flow"), a greater number of prevailing FTRs are made available by PJM than can be fully funded from day-ahead congestion revenues. In this case, a prevailing flow FTR may be "underfunded" and not fully hedge the holder from price differences on the affected pathway.

An FTR that imposes an obligation on the holder is described as a counterflow FTR. The holder of a counterflow FTR assumes the obligation to pay actual congestion costs on a defined pathway. In other words, the holder of a counterflow FTR has assumed the risk that the delivered price of electricity at the sink point of the pathway might be higher than the price at the source point of the pathway. A counterflow FTR typically has a negative financial value; which is to say that a party who acquires a counterflow FTR is paid a price out of the auction for assuming the congestion risk associated with the counterflow position.

FTRs are directional. A prevailing flow FTR can become a counterflow FTR (and vice versa) if the historical flow of electricity from one point to another reverses. For most pathways, this occurrence is unusual and results from an unexpected and dramatic change to the physical state of the system, such as the failure or the unplanned outage of major transmission facilities. Due to such an event, electricity that normally would move from point A to point B now moves from point B to point A. In this situation, entities that were holding prevailing flow FTRs across the pathway A to B are now holding counterflow FTRs (and vice versa).

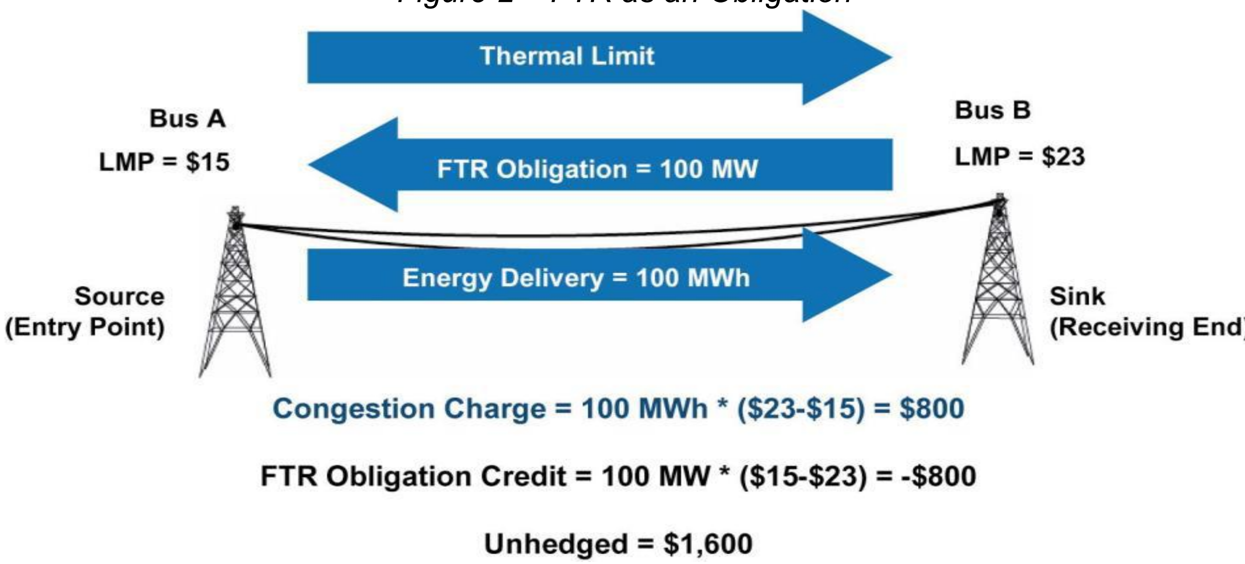
The following figures illustrate both the directional nature of an FTR and the financial value of the FTR. The value of an FTR is calculated hourly and is based upon the FTR MW reservation and the difference between Day-ahead Prices at the sink point and the source point designated in the FTR. The hourly economic value is positive (a benefit) when the path designated in the FTR is in the same direction as the congested flow (the Day-ahead Price at the sink point is higher than Day-ahead Price at the source point). This is illustrated in Figure 1.

Figure 1 – FTR as a Right



The hourly economic value of an FTR is negative (a liability) when the designated path is in the direction opposite to the congested flow (Day-ahead Price at the source point is higher than the Day-ahead Price at the sink point). However, if the holder of an FTR delivered energy along the designated path, the FTR holder would receive a congestion credit that would offset the FTR charge. This is illustrated in Figure 2.

Figure 2 – FTR as an Obligation



In sum, although the use of an LMP design for the energy markets may expose PJM Market Participants to price uncertainty for congestion charge costs, FTRs provide a means for Market Participants to obtain greater price certainty associated with their purchase of firm transmission service. Moreover, the FTR markets in PJM are fully transparent. The holder of every FTR is a matter of public information that can be accessed by every other Market Participant in the FTR markets. The auction results in a single clearing price for every FTR transacted on a given pathway which also is published by PJM and readily accessed by PJM Market Participants.

(3) Auction Revenue Rights (ARRs)

ARR holders have the right to the revenues resulting from the Annual FTR Auction; however, ARRs may also be converted into FTRs at the option of the Market Participant, as further detailed below. ARRs are financial entitlements (not physical ownership) that are (1) linked to the PJM‟s FTR product, and (2) allocated annually to PJM‟s Network and Firm Point-to-Point Transmission Service Customers in consideration of their payment of firm transmission tariff rates. The proceeds from the Annual FTR Auction fund ARRs. The annual ARR allocation process is conducted each year just prior to the Annual FTR Auction and during daily ARR reassignment. During the annual ARR allocation, participants request these rights in the form of a source, sink and MW value. For example, a PJM Market Participant would request an ARR from the Z generator to the X zone for 2 MW.

The collected funds from all of the FTRs bought or sold in the Annual FTR Auction are then distributed to ARR holders according to the rights awarded through the ARR allocation. ARRs provide a revenue stream to the firm transmission customers to offset the purchase price of FTRs.

An ARR holder may elect to convert the ARR into an FTR to hedge congestion charges in the PJM Day-ahead Energy Market. To convert an ARR into an FTR, the holder must self-schedule the FTR into the Annual FTR Auction on the same path as the ARR. Alternatively, the ARR holder may elect to retain the ARR and receive an associated allocation of the revenues from the Annual FTR Auction

(a) ARR Stage 1A Guarantee

The annual ARR process consists of two stages. Stage 1 consists of stages 1A and 1B, which allow ten year and annual ARRs, respectively, and stage 2 allows annual ARRs. The ARR allocation process is performed in accordance with Sections 7.4 and 7.5 of the Tariff and the PJM Manuals. The Stage 1A guarantee is documented in Attachment K-Appendix of the Tariff, Section 7.4.2, Auction Revenue Rights.

Specifically, PJM is required to recognize the existing constraints present in the Section 7.4.2(i) of the Tariff, which states:

> If any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible, then PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the Planning Year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances. For the purposes of this subsection, extraordinary circumstances shall mean an event of force majeure that reduces the capability of existing or planned transmission facilities and such reduction in capability is the cause of the infeasibility of such Auction Revenue Rights. Extraordinary circumstances do not include those system conditions and assumptions modeled in simultaneous feasibility analyses conducted pursuant to section 7.5 of Schedule 1 of this Agreement. If PJM allocates stage 1A Auction Revenue Rights as a result of

> this subsection (i) that would not otherwise have been feasible, then PJM shall notify Members and post on its web site (a) the aggregate megawatt quantities, by sources and sinks, of such Auction Revenue Rights and (b) any increases in capability limits used to allocate such Auction Revenue Rights.

As noted above, Section 7.4.2(i) of Schedule 1 of the Tariff illustrates the importance of maximizing ARR allocations by including explicit instructions for PJM to disregard the limitations injected in Stage 1A for subsequent stages if "any Auction Revenue Right requests made during stage 1A of the annual allocation process are not feasible."[13] Given the constraint imposed by Tariff section 7.4.2(i) alone, compliance with Tariff Section 7.4.2(i) can inherently result in the over allocation of ARRs when the ARRs requested in Stage 1A exceed the capability of the transmission system.

(b) ARR Ten Year Analysis

The Ten Year Analysis will check all existing stage 1A ARRs for the next ten years and apply a load growth factor as determined in the PJM load forecast report. This process will identify any facilities that will need to be upgraded to ensure that future stage 1A ARRs are feasible and the PJM planning group will add any such upgrades to the PJM RTEP.

B. Simultaneous Feasibility Test (SFT) Model

Pursuant to Section 7.5(a) of Attachment K-Appendix of the Tariff and PJM Manual 6, Section 9, PJM has been making simultaneous feasibility determinations on transmission outages using appropriate powerflow models of contingency-constrained dispatch since the incorporation of ARRs and FTRs into the PJM markets. The Simultaneous Feasibility Test (SFT) model is a determination process by which PJM tries to strike the right balance between fully funding FTRs and maximizing the use of the transmission system to ensure that there are sufficient revenues from Transmission Congestion Charges to satisfy all FTR obligations for the auction period under expected conditions, and to ensure that there are sufficient revenues from the annual FTR Auction to satisfy all ARR obligations.

Section 7.5(a) of Attachment K-Appendix of the Tariff states, in full:

[13] In such case, Section 7.4.2(i) specifically states that "PJM shall increase the capability limits of the binding constraints that would have rendered the Auction Revenue Rights infeasible to the extent necessary in order to allocate such Auction Revenue Rights without their being infeasible, and such increased limits shall be included in all modeling used for subsequent Auction Revenue Rights and Financial Transmission Rights allocations and auctions for the planning year; provided that, the foregoing notwithstanding, this subsection (i) shall not apply if the infeasibility is caused by extraordinary circumstances."

> (a) The Office of the Interconnection shall make the simultaneous feasibility determinations specified herein using appropriate powerflow models of contingency-constrained dispatch. Such determinations shall take into account outages of both individual generation units and transmission facilities and shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction that are not inconsistent with the determination of the deliverability of Generation Capacity Resources under the Reliability Assurance Agreement. The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient revenues from Transmission Congestion Charges to satisfy all Financial Transmission Rights Obligations for the auction period under expected conditions and to ensure that there are sufficient revenues from the annual Financial Transmission Right Auction to satisfy all Auction Revenue Rights obligations.[14]

The rules outlining implementation of this Tariff provision are provided by PJM in Manual 6, Section 9: Simultaneous Feasibility Test, which states, in relevant part:

> **Simultaneous Feasibility Test Overview** The Simultaneous Feasibility Test (SFT) is a market feasibility test run by PJM that provides revenue adequacy by ensuring that the Transmission System can support the subscribed set of FTRs or ARRs during normal system conditions. If the FTRs or ARRs can be supported under normal system conditions and congestion occurs, PJM will be collecting enough congestion charges to cover the FTRs or ARR credits, thus becoming revenue adequate. The purpose of the SFT is to preserve the economic value of FTRs or ARRs to the holders by ensuring that all FTRs or ARRs awarded can be honored. An SFT is run for each ARR or FTR requested.
>
> The SFT uses a DC power flow model that models the requested firm transmission reservations and expected network topology during the period being analyzed.

[14] Tariff, Attachment K-Appendix, Section 7.5 (a).

Inputs to the SFT model include:

- all newly-requested FTRs and ARRs for the study period,

- all existing FTRs and ARRs for the study period,

- transmission line outage schedules, thermal operating limits for transmission lines, that are expected to last for 2 months or more will be included in the determination of simultaneous feasibility for the Annual PJM FTR Auction and outages of five days or more shall be included in the determination of simultaneous feasibility for monthly PJM FTR auctions as well as outages of shorter duration that are determined through PJM analysis to be likely to cause FTR revenue inadequacy if not modeled.[15]

The SFT determination process, i.e., SFT model, for the Annual ARR allocation and Annual FTR Auction is a process that spans approximately five months and essentially consists of three phases (the pre-Auction stage, execution of the optimization engine, and rendering of results). PJM starts the simultaneous feasibility determination process for any given Annual ARR allocation and Annual FTR Auction in mid-January of the preceding Planning Period, which is approximately six weeks before the bidding window for the Annual ARR allocation, and ends the process on May 31 of the preceding Planning Period. Parts of the simultaneous feasibility determination process for the Annual ARR allocation and Annual FTR auction must be performed simultaneously because the time period covered for the Annual ARR allocation and Annual FTR auction is the same (i.e., the entire Planning Period, from June 1st through May 31st). The simultaneous feasibility determination process ultimately culminates in executing the FTR optimization engine – which includes the DC power flow model used to clear FTRs and allocate ARRs.

As stated in PJM Manual 6, Section 9, the SFT is a market feasibility test used by PJM during the simultaneous feasibility determinations; it is a test run by PJM that provides revenue adequacy by ensuring that the Transmission System can support the subscribed set of FTRs or ARRs during normal system conditions. The SFT is run both during the pre-Auction phase and during the execution of the optimization engine. The purpose of the SFT is to preserve the economic value of FTRs or ARRs to the holders by ensuring that all FTRs or ARRs awarded can be honored. Inputs to the pre-Auction

[15] PJM Manual 6: Financial Transmission Rights, Section 9: Simultaneous Feasibility Test, Simultaneous Feasibility Test Overview.

stage and execution of the optimization engine portions of the SFT model include: all newly-requested FTRs and ARRs for the study period; all existing FTRs and ARRs for the study period; thermal operating limits for transmission lines; transmission line outages that are expected to last for two months or more for the Annual PJM FTR Auction and outages of five days or more for monthly PJM FTR auctions, as well as outages of shorter duration that are determined through PJM analysis to be likely to cause FTR revenue inadequacy if not modeled; PJM reactive interface limits that are valid for the study period; and estimates of uncompensated power flow circulation into and out of the PJM Control Area from other Control Areas. Each of these inputs are evaluated during the simultaneous feasibility determination process and, based on the analysis, are either subsequently included or excluded from the pre-Auction phase and/or the optimization engine.[16]

The SFT models expected, planned system conditions based on past experience, historical and current data and other confidential information that is available to PJM *at the time the SFT model is executed*. The SFT does not model real-time system conditions, and, as explained in more detail in this report, it is real-time system conditions that are largely the cause of the present FTR underfunding that PJM is experiencing.

PJM creates the network topology portion of the DC power flow model in three steps. First, PJM analyzes the outages posted on OASIS by the Transmission Owners, and compiles an initial outage list. Next, PJM takes this initial outage list and groups outages that are occurring during the period of the allocation/auction where such outages do and do not occur simultaneously. Finally, PJM reviews these posted outages with the PJM Interconnection Coordination and System Operations Groups and the transmission owners when appropriate.

Longer-term scheduled windows for major transmission outages sometimes overlap during different times of the year but the actual outages are generally not permitted to occur simultaneously because doing so would cause reliability concerns and possible blackouts. Therefore, in the context of the simultaneous feasibility determination process, because PJM"s consideration of such outages "shall be based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction," PJM must exclude certain outages in order to model the best representation of outages to reflect the expected conditions during the auction time period.

[16] The Commission has indicated that PJM must have the ability to exercise its expert and independent judgment to make determinations of simultaneous feasibility for the ARR allocations and annual FTR auctions. *See PPL EnergyPlus, LLC v. PJM Interconnection, L.L.C.*, 134 FERC ¶ 61,263 at PP 41-44 (2011) ("PPL March 31st Order), *reh'g denied*, 136 FERC ¶ 61,060 at P 29 (2011) ("PPL July 27th Order"), appeal docketed, No. 11-1341 (D.C. Cir Sept. 23, 2011).

PJM performs the annual SFT process once per year and each transmission right allocated in this process must be allocated for the entire year. Therefore, in many instances it is impractical and unrealistic to model all scheduled outages in this single snapshot because the reality is they will occur during different time periods. If these multiple outages were all modeled together for the entire year, notwithstanding that several or most of the outages may have been for significantly less time, the model would significantly understate the transmission system capability and the optimization program would likely fail to converge on a solution because of a power imbalance. This means that the optimization program would be unable to solve. In other words, the optimization program would be unable to produce a base model with which to begin the technical assessments necessary to evaluate transmission rights feasibility.

As a final step in reviewing the outage list, PJM market engineers will also review all transmission outages of interest with PJM‟s System Operations Group, Interconnection Coordination Group and the Transmission Owners when appropriate, to assess the likelihood of the outages actually occurring. As noted above, in many instances outages will be scheduled in OASIS that are not yet approved and that may/will otherwise be delayed, cancelled, or rescheduled for reasons including, but not limited to cancelled transmission upgrades, conflicts with other outages, maintenance cancelations, etc. Many times this information is confidential, and is gathered by the PJM System Operations Group and Interconnection Coordination Group working with the Transmission Owners of the facilities in question. Accordingly, the PJM Members will not be able to access this information from simply viewing the outages posted on the PJM OASIS. Therefore, after this portion of the analyses is performed on the initial OASIS outage list, PJM, based on reasonable assumptions about the configuration and availability of transmission capability during the period covered by the auction, determines the actual outages that will be placed in the optimization program. To maintain transparency in the process, PJM posts a separate FTR outage list to the FTR web page. This separate FTR outage list is posted to all FTR holders, along with the actual FTR DC power flow model, a minimum of one week before the bidding window opens so that PJM members have a transparent view of the conditions to be used in the DC power flow model for execution of the optimization engine.

C. PJM is tasked with balancing the competing interests of maximizing the use of the transmission system and fully funding FTRs

Consistent with the EPAct requirements, the Commission issued Order No. 681 in 2006[17] establishing certain guidelines for RTOs and ISOs to follow in revising their tariffs to support long-term firm transmission rights (LTTRs). Guideline 2 required: The

[17] *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 169, reh‟g denied, Order No. 681-A, 117 FERC ¶ 61,201 (2006) (“Order No. 681”) (emphasis added). The regulations adopted by Order No. 681 are codified at 18 C.F.R. § 42.1.

long-term firm transmission right must provide a hedge against LMP congestion charges or other direct assignment of congestion costs for the period covered and quantity specified. Once allocated, the financial coverage provided by a financial LTTR should not be modified during its term (the „full funding‟ requirement) except in the case of extraordinary circumstances or through voluntary agreement of both the holder of the right and the transmission organization.

While PJM recognizes that ideally FTRs should be fully funded, and it is PJM‟s goal to achieve full funding, full funding of FTRs is not a mandatory requirement. In PJM‟s view, it is not under a legal obligation to guarantee an absolute, 100% funding of FTRs. Rather, what PJM is required to do is balance the competing interests of maximizing the use of the transmission system and fully funding FTRs. The Commission kept this balance in mind when it recently determined, in *PPL EnergyPlus* that "[t]he purpose of conducting the simultaneous feasibility determination is thus to allocate the maximum number of ARRs that can be allocated while ensuring that FTRs are fully funded, *not to ensure that FTRs can never be underfunded*."[18]

(1) The allocation of ARRs is the means by which PJM provides firm service to network and point-to-point customers

PJM, as a transmission provider, is obligated to "ensure the development and operation of market mechanisms to manage congestion"[19] and to maximize the use of the transmission system to allow the firm transmission service customers who paid for the transmission system to recover the fixed, embedded costs of the transmission system.[20] In PJM, as is true in other locationally-priced wholesale electric markets, the open-access directive to offer customers firm transmission service is met by providing these customers FTRs that serve to hedge the transmission customer against congestion costs that might arise in scheduling power over a given pathway. Organized electricity markets are said to offer "financially firm" transmission service (as a more efficient option to "physically firm" service as is offered by transmission providers in non-market environments).[21]

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[18] *See* PPL March 31st Order at P 46 (emphasis added); PPL July 27th Order at P 29.

[19] *Regional Transmission Organizations,* Order No. 2000, FERC Stats. & Regs. ¶ 31,089, at 31,126 (1999), *order on reh'g*, Order No. 2000-A, FERC Stats. & Regs. ¶ 31,092 (2000), *aff'd sub nom. Pub. Util. Dist. No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

[20] *Promoting Wholesale Competition Through Open Access Non-Discriminatory Transmission Services by Public Utilities; Recovery of Stranded Costs by Public Utilities and Transmission Utilities,* Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,692-31,693 (1996), *order on reh'g,* Order No. 888-A, FERC Stats. & Regs. ¶ 31,048, *order on reh'g*, Order No. 888-C, 82 FERC ¶ 61,046 (1998), *aff'd in relevant part sub nom. Transmission Access Policy Study Group v. FERC,* 225 F.3d 667 (D.C. Cir. 2000), *aff'd sub nom. New York v. FERC*, 535 U.S. 1 (2002).

[21] The Final Rule issued by the Commission issued in *Long-Term Firm Transmission Rights in Organized Electric Markets*, Order No. 681, 116 FERC ¶ 61,077 (2006), *reh'g denied*, Order No. 681-A, 117 FERC ¶ 61,201 (2006) is informative here. The Commission concluded that: "While transmission organizations may provide firm „physical‟ transmission rights on a long-term basis, the cost of transmission service in transmission organizations that use LMP to manage congestion is dependent on the cost of that

Clearly, FTR funding is an important interest in the same sense that avoiding the physical curtailment of firm customers is an important objective for a transmission provider. Section 7.5(a) of Schedule 1 of the Operating Agreement specifically provides that: "The goal of the simultaneous feasibility determination shall be to ensure that there are sufficient revenues from Transmission Congestion Charges to satisfy all Financial Transmission Rights Obligations for the auction period under expected conditions and to ensure that there are sufficient revenues from the annual Financial Transmission Right Auction to satisfy all Auction Revenue Rights obligations." Equally important, however, is the Commission‟s policy goal promoting wide, open access; or put another way, its "desire to maximize the use of the transmission provider‟s system."[22] In PJM, maximizing use of the transmission system is achieved by providing customers as much firm transmission as can reasonably be expected, which is accomplished by allocating to firm customers a sufficient number of ARRs to hedge their expected congestion charges.

(2) Optimizing the use of the transmission system by trying to meet as many customer requests for ARRs as can reasonably be met reflects well established commission policy

The Commission‟s purpose in issuing landmark Order No. 888 was to foster greater competition in wholesale power markets by reducing barriers to entry in the provision of transmission service, and it proposed to do so by remedying undue discrimination in the electric industry by providing open access to the transmission system.[23] Carrying forward this mission of maximizing open access, the Commission issued Order No. 890 to increase non-discriminatory access to the grid by, among other things, increasing "the efficient utilization of transmission by eliminating artificial barriers to use of the grid . . . while also ensuring that reliability to native load customers is maintained."[24] Based on the principles underlying both Orders No. 888 and 890, it is clear that granting transmission service and giving broad access to the transmission system is the cornerstone of open access.

Accordingly, PJM‟s objective is, and always has been, to both ensure full funding of FTRs while also maximizing the use of the transmission system. Achieving both goals requires striking a difficult balance and PJM has historically done an excellent job of achieving both goals year in and year out.

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congestion. We agree with APPA that for a transmission right to be „firm,‟ it must be firm as to both quantity and price. In the LMP context, this means „firm transmission rights‟ must be firm as to both the „physical‟ component of the right and the „financial‟ component of the right. FTRs can hedge congestion costs (when matched to the physical path of the transmission right) and make transmission rights in an LMP system „firm,‟ . . ." Order No. 681 at P 82.

[22] *PJM Interconnection, L.L.C.*, 84 FERC ¶ 61,212 at 5.

[23] Order No. 888, FERC Stats. & Regs. ¶ 31,036, at 31,635.

[24] *Preventing Undue Discrimination and Preference in Transmission Service*, Order No. 890, 72 Fed. Reg. 12,266 at P 4 (Mar. 15, 2007), FERC Stats. & Regs. ¶ 31,241 (2007).

D. FTR Funding History

As illustrated in the below table, while PJM has generally been at or near 100% revenue adequacy for FTRs since the incorporation of FTRs into the PJM markets, PJM did experience FTR revenue inadequacy in the 2010/2011 Planning Period, and is currently experiencing FTR revenue inadequacy in the 2011/2012 Planning Period.

Table 1. Historical FTR funding Percentages

Planning Period	Percent
2003-04	97.7%
2004-05	100%
2005-06	90.7%
2006-07	100%
2007-08	100%
2008-09	100%
2009-10	96.9%
2010-11	84.9%
2011-12 (through March 2012)	83.2%

Because PJM had experienced FTR revenue inadequacy in prior years, the mere fact that PJM was experiencing revenue inadequacy in the 2010/2011 Planning Period did not, in and of itself, justify immediate and significant changes during the 2010/2011 Planning Period to PJM‟s modeling or revenue funding for what may have otherwise turned out to be a single unique year. As noted above, the Operating Agreement expressly contemplates the situation of FTR revenue inadequacy, and the Commission has agreed that these Operating Agreement provisions do not ensure that FTRs can never be underfunded.[25]

Nonetheless, in response to the 2010/2011 Planning Period revenue inadequacy, the PJM Market Implementation Committee ("MIC") approved the creation of the FTR

[25] *See* case cited *supra* note 16.

Task Force ("FTRTF") at its March 17, 2011 meeting. The FTRTF was charged with investigating the causes of the FTR revenue inadequacy issue that occurred during the 2010/2011 Planning Period[26] and identifying potential improvements, including modeling, [27]that could be made to minimize the revenue inadequacy going forward.

4. Stakeholder Efforts/FTR Task Force

PJM and its stakeholders have been concerned about the recent FTR revenue shortfalls since the funding levels started to drop in the Fall of 2010. PJM conducted a FTR technical conference on January 26, 2011 which was a detailed conference explaining the ARR and FTR process, funding, modeling, PJM daily activities, and the inputs that it expected to incorporate into the optimization program for the 2011/2012 Planning Period. This technical conference was used as an education tool for PJM Members.[28]

In March of 2011, the PJM FTRTF was created by PJM Members.[29] The responsibility of the FTRTF was to identify specific causes of FTR revenue inadequacy, identify discrepancies between the modeling of the Day-ahead, FTR, and Real-Time Energy Markets, explore and identify improvements that can be made to the annual modeling to minimize the risk of underfunding while maximizing opportunity for ARR and FTR availability, and explore alternative methods of funding FTR congestion revenue and shortfalls. Specific details of the FTRTF can be found in Appendix A of this document. The result of the FTRTF was a membership consensus on several process improvements. In addition, a change to remove bids that clear at a zero cost and provide no impact on binding constraints was approved earlier in FTRTF process. There were no additional Tariff or Operating Agreement language changes as a result of the PJM stakeholder process concerning FTR revenue adequacy.

Further, back in 2007 and during the 2011 FTRTF meetings, the PJM stakeholders also explored an option to move to a seasonal ARR allocation and FTR auction to replace the current Annual ARR and FTR Auction process. This seasonal approach would have allocated seasonal ARRs and FTRs as opposed to full year rights. The 2007 FTR Working Group concluded that given the administrative overhead and participant uncertainty involved with moving to a seasonal approach compared to the

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[26] *See generally* the January 26, 2011 FTR Technical Meeting materials located on the PJM Website at http://www.pjm.com/committees-and-groups/ committees/mic.aspx.
[27] *See generally* the January 26, 2011 FTR Technical Meeting materials located on the PJM Website at http://www.pjm.com/committees-and-groups/ committees/mic.aspx.
[28] *See generally* the January 26, 2011 FTR Technical Meeting materials located on the PJM Website at http://www.pjm.com/committees-and-groups/ committees/mic.aspx.
[29] *See generally* the FTR Task Force meeting materials located on the PJM website at http://pjm.com/committees-and-groups/task-forces/ftrtf.aspx .

relatively small improvement in revenue adequacy, PJM should not move forward with development of a seasonal approach. In 2011, the FTRTF also failed to advance the seasonal allocation and auction package for the same reason.

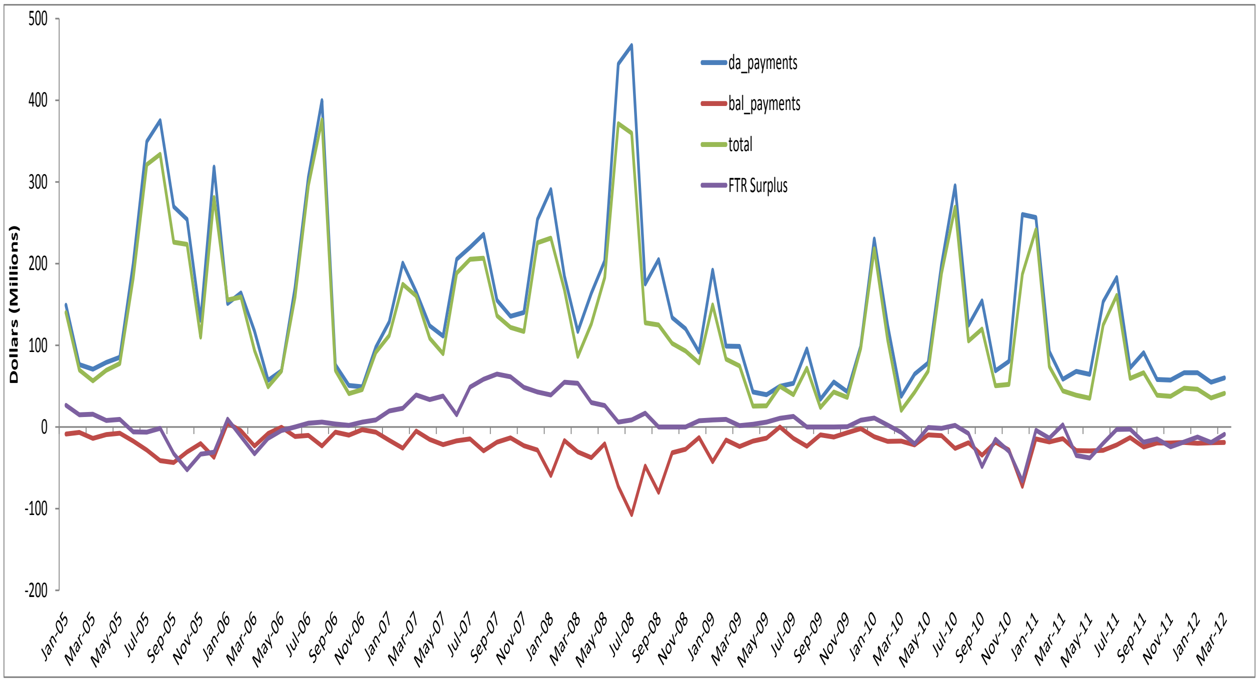
5. Causes FTR Underfunding

A. Overview

FTR underfunding occurs when the total amount of congestion charges and excess FTR auction revenue (hereinafter “surplus revenue” or “excess revenue”) is not sufficient to cover the value of FTR Target Allocations. Excess FTR auction revenue used for FTR funding includes all monthly, long term, and annual auction revenue minus ARR credits, however such revenues are a relatively minor contributor to FTR funding.[30] In PJM, congestion collections from both the Day-ahead Energy Market and Real-time Energy Market are currently used for FTR funding. The real-time balancing market congestion is calculated as the delta in load, generation and other transactions between the day-ahead and actual real-time operations valued at the LMP prices from the real-time market. Balancing congestion exists because system conditions are never exactly the same in real-time as captured in the Day-ahead Energy Market. The figure below shows the payments attributable to day-ahead congestion, balancing congestion and total congestion from January 2005 through March 2012. The balancing congestion component of total congestion has been largely negative since January 2005. There is no long term trend in balancing congestion payments.

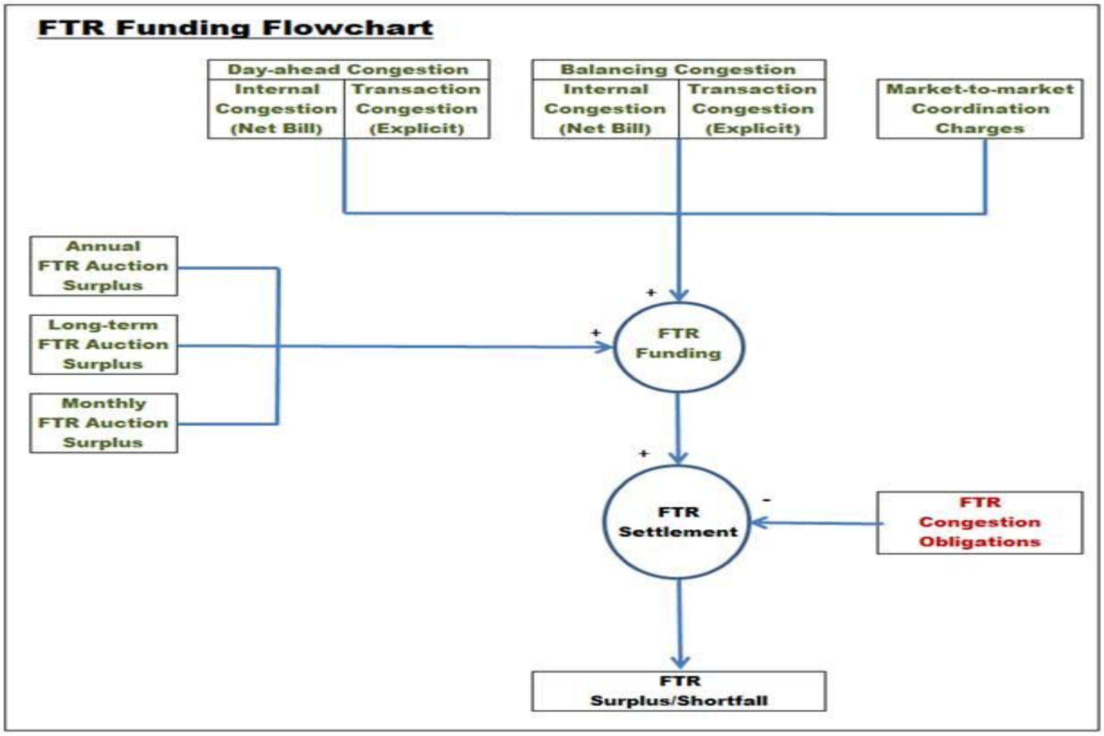
[30] Excess FTR Revenue after payout of ARR credits has averaged 8.8% over the last three Planning Periods through December of 2011.

Figure 3: Monthly balancing, day-ahead and total payments: January 2005 through March 2012



The main components of the congestion collections include net bill (also called "implicit") congestion, explicit congestion, and market to market payments. Implicit congestion consists of generation to load deliveries within the PJM footprint along with spot market purchases and sales. Implicit congestion is internal PJM congestion. Explicit congestion includes congestion from imports, exports and wheel-through PJM transactions that result in energy entering, leaving or being transmitted through the PJM balancing authority. Finally, market to market payments are the payments either to or from the Midwest Independent System Operator (Midwest ISO) from coordinated flowgates which both PJM and the Midwest ISO control. The diagram below represents the sources of funding for FTR holders.

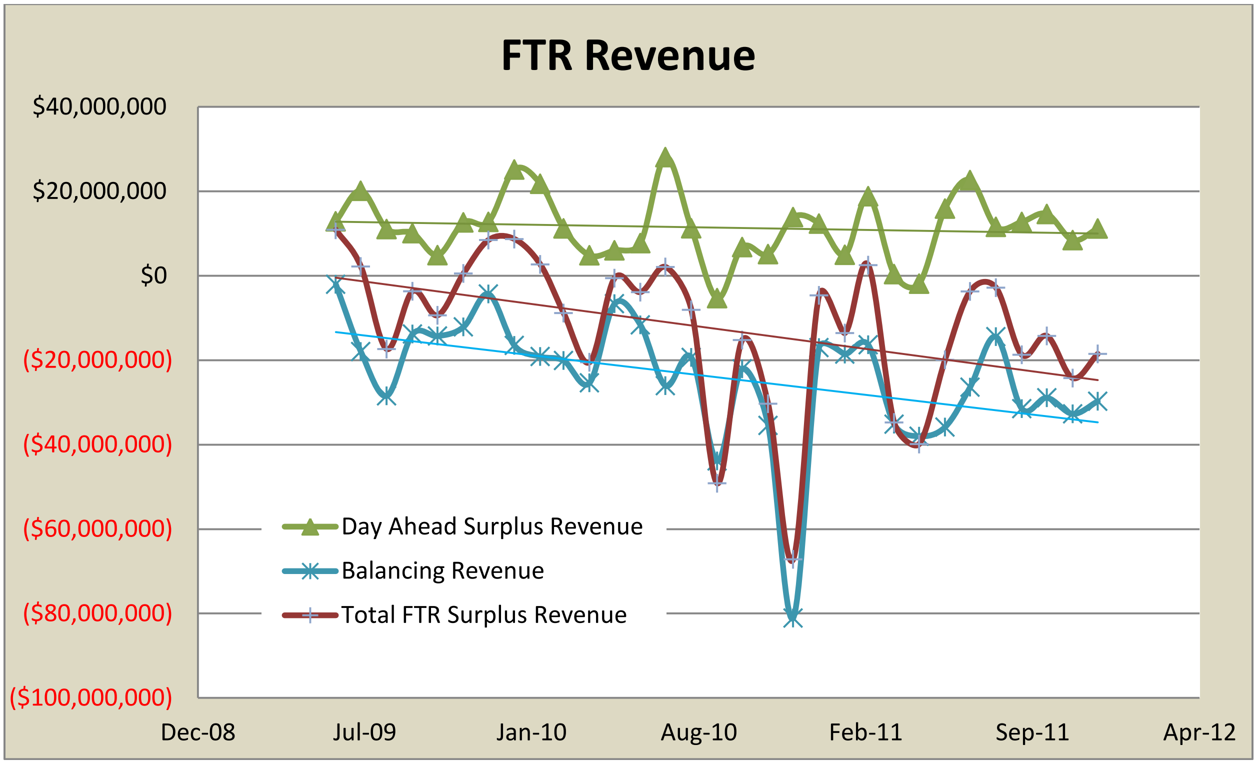
Figure 4: Sources of FTR funding



B. Recent Trends

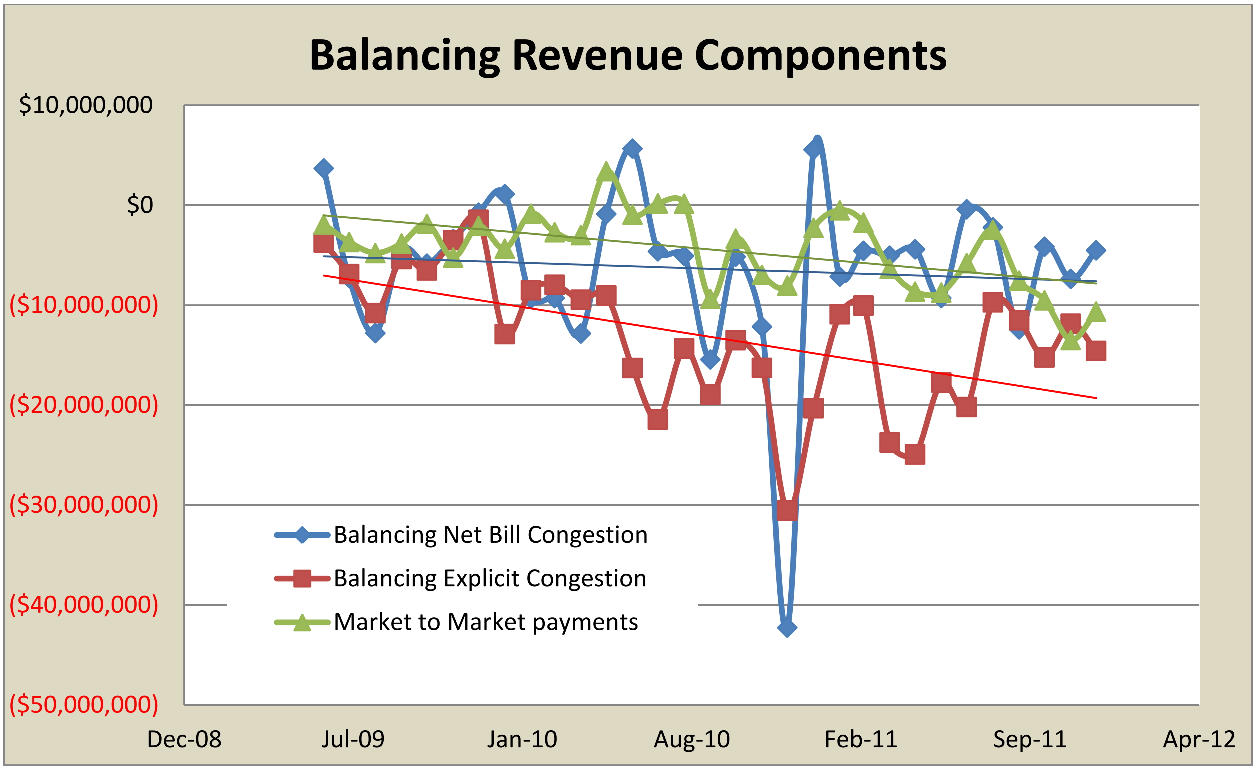
The various congestion components used to fund FTRs were observed over the last several years to determine if any component has changed relative to previous years in which the FTR funding has been above or closer to 100%. The below graph shows the trend for the revenue used to fund FTRs. This graph displays the day-ahead excess revenue in excess of FTR Target Allocations, balancing revenue which includes balancing net bill, balancing explicit, and market to market payments, and total surplus revenue. The total surplus revenue will be negative when the FTR revenue adequacy is less than 100%. As can be seen from this graph, the day-ahead surplus revenue has been relatively constant since June of 2009. However, the balancing revenue has been trending downward since June of 2009 which has resulted in the downward trend in total surplus revenue.

Figure 5: FTR, Day-ahead Surplus, and Balancing Revenue Trends



The above findings can be observed in more detail by looking at the components of the balancing revenue in order to determine where the downward trend of balancing revenue and resulting FTR revenue adequacy originated. The below graph shows the three main components of the balancing revenue which are the balancing net bill congestion, balancing explicit congestion, and the market to market payments. The trend of the balancing net bill congestion is basically flat despite the large negative month in December of 2010 in which multiple regional facilities were simultaneously out of service. The explicit balancing congestion and the market to market payments both have a downward trend since June of 2009 with the explicit balancing congestion being larger. It is apparent that the negative explicit balancing congestion is a major contributor to the downward trend in FTR revenue and corresponding FTR revenue adequacy.

Figure 6: Trend of Balancing Revenue Components



If less transmission system capability is available in the Real-time Energy Market than in the Day-ahead Energy Market, then negative balancing congestion can result. Since most of the transmission system capability is subscribed in the Day-ahead Energy Market, the amount of balancing congestion is generally near zero or negative. Negative balancing congestion is common because for the reasons described in more detail below, transmission system capability in the Real-time Energy Market is generally the same or less than transmission system capability in the Day-ahead Energy Market.

C. Reasons for Negative Balancing Congestion

(1) Congestion on PJM borders

There are two primary reasons for the recent downward trend of balancing explicit congestion in the PJM markets. The first reason is the gradual increase in congestion along the PJM borders over the past several years and in particular an increase in negative balancing congestion associated with these facilities. The trend of an increasing percentage of transmission congestion occurring on facilities at PJM„s market borders is driven by: 1) reduced internal PJM west to east flows due to a relative increase in coal resource offer prices in the western part of the PJM Region and a relative reduction in gas-fired resource offer prices in the eastern part of the PJM Region that results in decreased internal congestion; 2) increased wind resources impacting the western part of the PJM Region; and 3) the completion of the 500kV TrAIL Line.

The below table shows the increasing trend of congestion along the PJM borders, the percentage of congestion hours associated with facilities located at the PJM borders since 2005, and the percentage of negative balancing congestion attributable to these facilities. It is apparent from this table that over recent years the congested hours and negative balancing congestion from facilities located near the PJM borders have been higher than was previously experienced. This negative balancing congestion reduces the total congestion dollars used to fund FTRs. Congestion on facilities affected by system conditions in neighboring control areas are more likely to result in negative balancing congestion because of factors such as unpredictable external flow patterns, real-time wind resource output not being offered in the PJM Day-ahead Energy Market, external control area transmission system topology changes for which PJM does not have forward information, and unforeseen external transmission outages. There are many unforeseen external transmission outages because in some cases the outage scheduling requirements for external RTOs require minimal notice. The deviation between the conditions modeled in the Day-ahead Energy Market and those experienced in the Real-time Energy Market increases for those transmission constraints near market borders because those constraints are more susceptible to changes in real-time operational conditions outside of the PJM Region that cannot be modeled accurately in the PJM Day-ahead Energy Market. Therefore, the result of the increasing percentage of congestion occurring on facilities near the market border is increased negative balancing congestion.

Table 2: Congestion from Facilities located Near PJM Borders

Year	% of Congested Hours from Facilities located near PJM borders	% of Negative Balancing Congestion from Facilities located near PJM borders
2005	1.5%	-2.4%
2006	4.4%	10.8%
2007	5.5%	6.6%
2008	9.4%	10.2%
2009	22.1%	44.3%
2010	13.8%	20.8%
2011	32.9%	53.4%

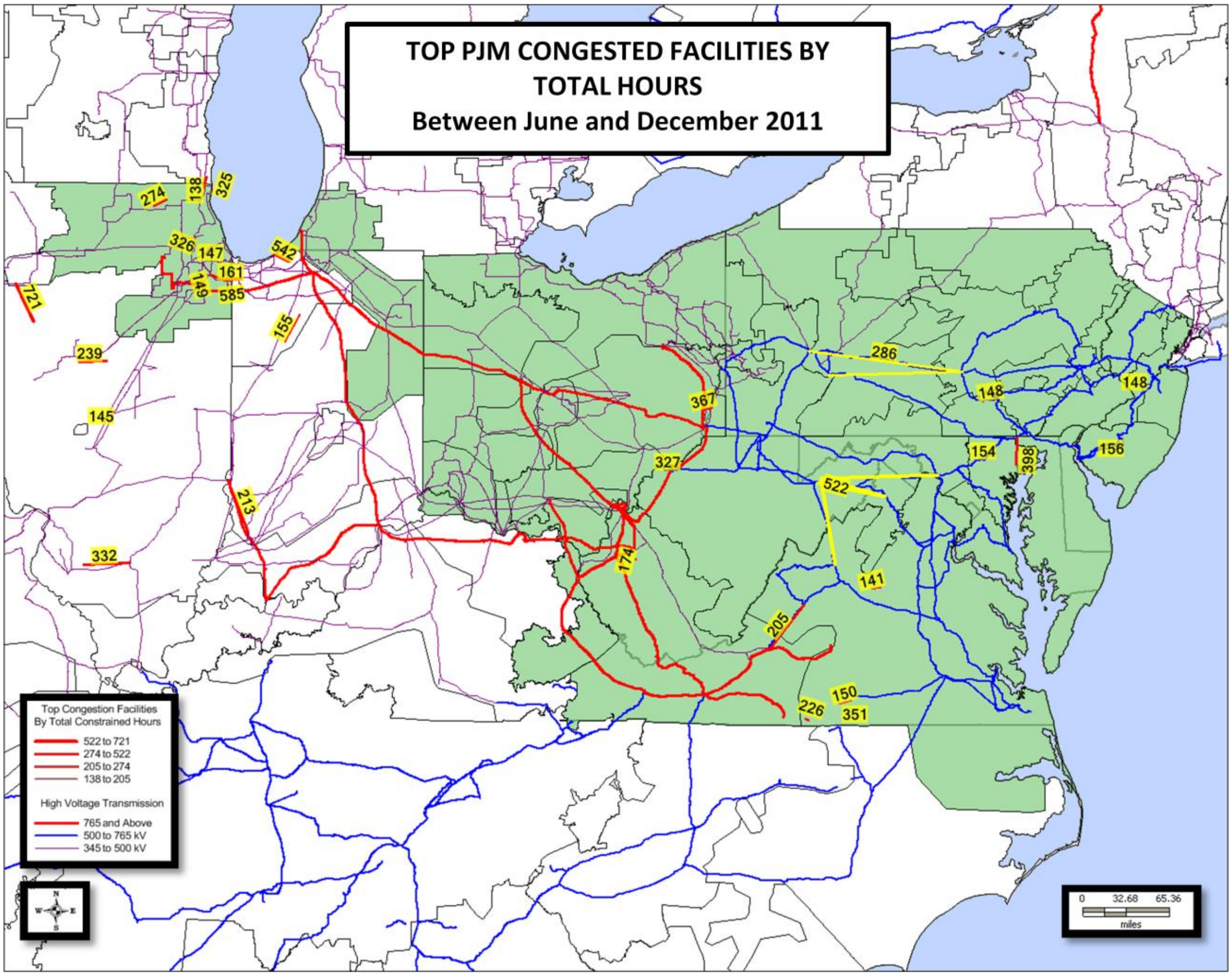
To further demonstrate this occurrence the below table shows the top 30 congested facilities by constrained hours in PJM since June of 2011 when the TrAIL backbone transmission project was energized. This table shows that the top three congested events account for 12% of constrained hours and all three are market to market coordinated flowgates. The table further reflects that 17 of the top 30 frequently congested constraints are either market to market coordinated flowgates or located along the PJM border which accounts for about 33% of total congestion hours as can be seen from the highlighted rows in the table.

Table 3: Real-Time Congestion Event Hours

PJM Real-Time Congestion Events 6/1/11-12/31/11		
Congestion Event	Total Hours Constrained	% Hours Constrained
LINE 161 KV Oak Grove-Galesburg 161kV l/o Nelson-Electric Junction 345kV FG	721	4.7%
LINE 345 KV CRETEIPP-STJOHNS TIE	585	3.8%
LINE 138 KV Michigan City - Laporte 138 kV flo Dumont -Wilton Center 765 kV FG	542	3.5%
APSOUTH	522	3.4%
LINE 230 KV GRACETON-RAPHAERD 2313	398	2.6%
LINE 138 KV BRUES-WBELLAI2	367	2.4%
CLOVER 500 KV CLOVER TX9 XFORMER	351	2.3%
LINE 345 KV Prairie State-W Mt Vernon 345 kV l/o St Francis-Lutesville 345 kV FG	332	2.2%
BELMONT 500 KV BELMONT TRAN 3 XFORMER	327	2.1%
LINE 345 KV 66 E FRN-945 CRET 6607	326	2.1%
LINE 138 KV Kenosha-Lakeview 138 l/o Pleasant Prairie-Zion 345 kV FG	325	2.1%
50045005	286	1.9%
LINE 138 KV 12204 -141 PLEA 12204 2	274	1.8%
LINE 138 KV Powerton Jct-Lilly 138 kV l/o Duck Creek-Tazewell 345 kV FG	239	1.6%
LINE 138 KV DANVILLE-EDANVILL	226	1.5%
LINE 345 KV Breed-Wheatland 345 l/o Jefferson-Rockport 765 kV FG	213	1.4%
LINE 500 KV CLOVERDA-LEXINGTO 500KV	205	1.3%
LINE 138 KV RUTH-TURNER	174	1.1%
LINE 138 KV ST JOHN-LIBERTY PARK 138 KV L/O ST JOHN-GREEN ACRES 138 KV FG	161	1.1%
LINE 69 KV SHIELDAL-VINELAND 0711-3	156	1.0%
LINE 138 KV Monticello-East Winamac 138 kV l/o Schahfer-Burr Oak 345 kV FG	155	1.0%
NORTHWES230 KV NORTHWES SD2371 SER DEV	154	1.0%
LINE 115 KV HALIFAX -MTLAURE4 33C	150	1.0%
LINE 345 KV BURNHAM-MUNSTER2 TIE	149	1.0%
EMILIE 230 KV EMILIE 8TR XFORMER	148	1.0%
LINE 115 KV CLY-COLLINS 975-2	148	1.0%
STJOHNS 345 KV ST JOHN 345/138 KV L/0 GREEN ACRES-ST JOHN 345 KV FG	147	1.0%
LANESVL 345 KV Lanesville 345/138-kV TX l/o Kincd-Lathm-Blue Mnd+Kincd-Pawnee+Latham TR1 FG	145	0.9%
LINE 230 KV HOLLYMTP-CHARLTSV 2054A	141	0.9%
LINE 138 KV Lakeview-282 Zion 138 kV l/o Zion-Pleasant Prairie 345 kV FG	138	0.9%

The below map of PJM displays the physical location of the facilities from the above table. Most of these facilities are located near the PJM borders and therefore are directly affected by factors that are difficult to model with precision in the Day-ahead Energy Market. These factors include unpredictable external flow patterns, real-time wind resource output not being offered in the Day-ahead Energy Market, external control area transmission topology changes for which PJM does not have forward information, and unforeseen external transmission outages.

Figure 7: Top PJM Congested Facilities



In addition, the amount of market to market flowgates has continued to increase since the evolution of the PJM-Midwest ISO market to market process. The below table shows the quantity of market to market flowgates added over the last few years along with the congestion hours associated with these facilities. As the table indicates, there were 188 new market to market flowgates added to the PJM-Midwest ISO coordination process in the past two years, 150 of which were added at Midwest ISO"s request. These additional flowgates that are mainly controlled by Midwest ISO are major contributors to the PJM border congestion that has created an increased balancing congestion trend and resulting FTR Revenue Inadequacy.

Table 4: Market to market flowgates added without ability to model in annual ARR/FTR process.

	Market to Market Flowgates added without ability to model in Annual ARR/FTR process			
	2010		2011	
Controlling RTO	Flowgates Added	Congestion Hours	Flowgates Added	Congestion Hours
MISO	42	1105	108	2086
PJM	8	81	30	891

Also, the addition of these market to market flowgates creates an infeasibility in the PJM annual ARR and FTR process because they could not be modeled in the simultaneously feasibility process since they did not exist when the Annual ARR and FTR process was conducted in the beginning of each year. The below table shows the percentage of congestion hours on flowgates that PJM did not have the ability to model in the Annual ARR and FTR processes. In 2011, there were 2,977 total congestion hours on flowgates, or 40% of the total 2011 congestion hours on facilities located along the PJM borders, that PJM did not have the ability to model in its annual SFT process. Furthermore, some of these flowgates have and will continue to create a stage 1A infeasibility for which PJM cannot prorate rights because of current Tariff and Operating Agreement requirements. PJM is in the process of planning transmission upgrades through the annual, 10-year ARR analysis to ensure future stage 1A feasibility. However, since these flowgates are new to the market there will not be upgrades built for several years.

Table 5: Percentage of Congestion from Facilities located near PJM borders without ability to model in annual ARR/FTR process.

Year	Congestion Hours from Facilities located near PJM borders	Congestion Hours from Flowgates added without ability to model in Annual Process	Percentage of Congestion Hours from facilities located near PJM borders without ability to model in Annual Process
2010	3242	1186	36.6%
2011	7385	2977	40.3%

(2) Transmission Outages

The second major factor contributing to the continued downward trend of balancing congestion in the PJM markets is an increase in the number of transmission outages over the past few years, and in particular the number of emergency, summer, and winter peak period outages. Because PJM often receives notice of emergency outages after it has completed the modeling for the Day-ahead Energy Market, when the outage is taken in real-time it will create a direct deviation from the day-ahead model, thus increasing the likelihood for negative balancing congestion. Additionally, over the last several years there has been an increase in unscheduled transmission outages occurring during the summer and winter months due to weather related damage to facilities and NERC alert facility rating requirements, the result of which is an increase in congestion during times when the system is already limited and during which PJM does not, in the ordinary course, allow outages to be taken.

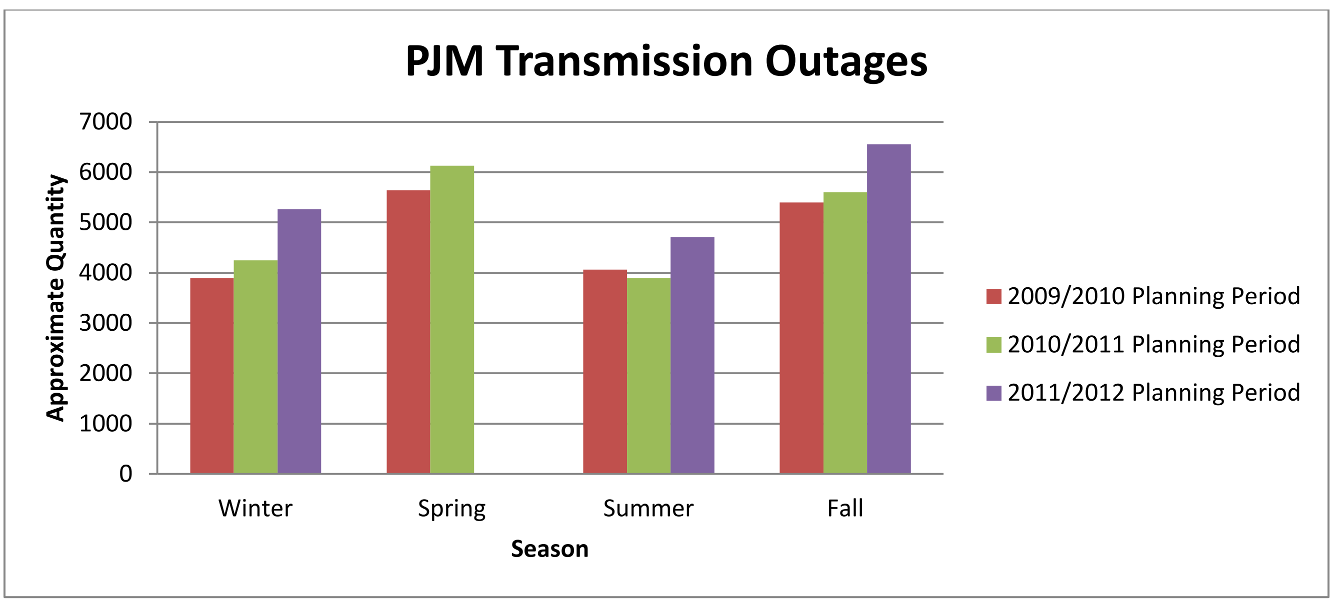
The timeline with which transmission outages are submitted can also have a significant impact on the congestion, and therefore revenue inadequacy, a given outage causes. Over the years, PJM has worked with its Transmission Owners and other stakeholders to establish timing requirements for transmission outage submission that both allow outages to be adequately considered in the transmission right allocation and auction processes, and allow sufficient coordination to occur with other transmission facility outages as well as generation outages. Specifically, PJM requires that:

- Transmission Owners use best efforts to submit transmission planned outage schedules exceeding five (5) working days in duration one year in advance, but no later than the first of the month six (6) months preceding the requested start date;
- Transmission Owners must submit notice of all transmission planned outages to PJM by the first of the month preceding the month during which the outage is scheduled; and
- Transmission Owners must submit outages exceeding 30 days in duration by February 1st preceding the Planning Period during which the outage is scheduled to occur.

PJM is able to require the Transmission Owner submitting the outage to reschedule the outage based on anticipated system impacts, including congestion, if the above timelines are not met. By contrast, Midwest ISO requires only fourteen (14) days notice for transmission outage schedules. PJM has also observed that Midwest ISO and its transmission owners are reluctant to adjust outage schedules once they are submitted. This relatively short notification timeline in Midwest ISO has caused the need for PJM outage rescheduling or in the alternative, significant congestion in PJM resulting in significant risk of revenue inadequacy as evidenced by the inadequacy PJM has observed on constraints near the border.

The below graph shows the approximate number of PJM transmission outages for each season and the trend of increasing outages for each season. Additionally, the significantly increasing volume of scheduled transmission outages associated with new facilities or upgrades to existing facilities designed to resolve reliability violations identified in the PJM RTEP have, for the period of the outage, reduced the available transmission margins that have historically existed. This reduction in transmission margin tends to exacerbate the financial impact of any unforeseen emergency or weather-related outage which has significantly increased the magnitude of negative balancing congestion. While this reduced transmission margin impact is temporary for any given transmission outage, the sheer volume of construction and maintenance outages, stacked one after the other, has eroded the transmission capability and reduced the system„s tolerance to unforeseen outages for persistent periods of time. As a result, unforeseen outages have caused larger negative balancing impacts than they have had historically. In fact, the scheduling of transmission outages to perform necessary and critical upgrades to avoid the potential for near-term reliability violations has required PJM to approve transmission outages that would normally have been delayed because of their potential impact on transmission congestion.

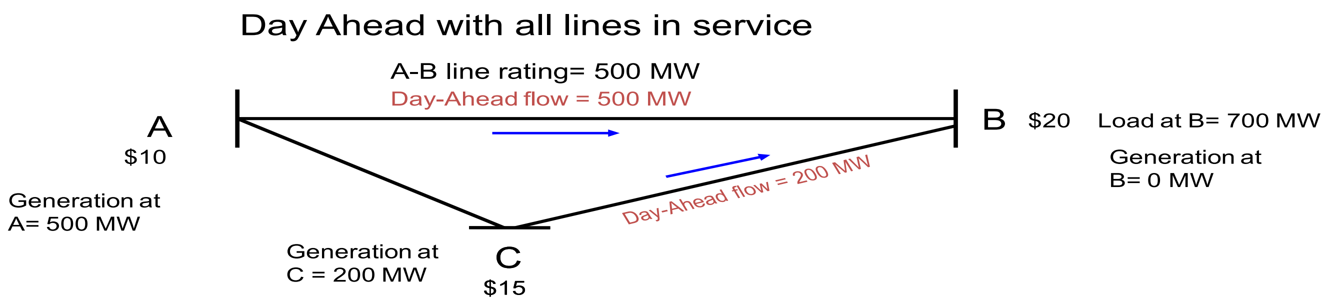
Figure 8: PJM Transmission Outages



The following example shows the impact of an unforeseen transmission outage on negative balancing congestion.

Example 1: Demonstration of Negative Balancing Congestion from unforeseen outage

In the below diagram the Day-ahead Energy Market is represented by a three bus system with all lines in service and the total day-ahead congestion is equal to $6000.



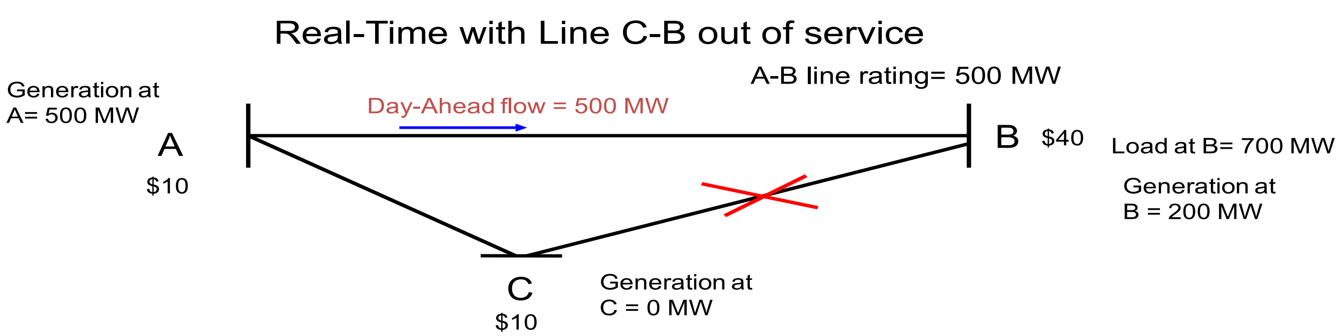
Congestion Calculation :

Generation
A=500*$10=$5,000
B= 0*$20=$0
C=200*$15=$3,000
Total=$8,000

Load
B=700*$20=$14,000
Total=$14,000

Total Congestion = Load - Generation
= $14,000-$8,000=$6,000

If an emergency or unforeseen outage occurs in real-time on this three bus system on line C to B then it could be represented by the below diagram.



Balancing Congestion Calculation :

Balancing Generation
A=0*$10=$0
B= 200*$40=$8,000
C=-200*$10=-$2,000
Total=$6,000

Balancing Load
B=0*$40=$0
Total=$0

Total Balancing Congestion = Balancing Load – Balancing Generation
= $0-$6,000=-$6,000

This unforeseen outage will create negative balancing congestion because the balancing congestion is calculated from the deviations in generation and load between the Day-ahead and Real-time Energy Markets. In the example, the balancing congestion calculation is derived from this deviation which would otherwise not have been there if the unforeseen outage did not occur in the market. It is important to note that in the example the day-ahead congestion is equal to $6000 and the balancing congestion is equal to negative $6000 dollars. Thus, under the current Tariff requirements the sum of these congestion dollars, in other words $0, will be used to fund FTR Target Allocations. Therefore, FTR holders will have zero funding from this example and will be responsible for unforeseen circumstances that occur in real-time over which they have no control.

D. Reductions in System Capability

In addition to transmission outages, the total system capability has been further reduced due to a significant increase in transmission facility de-ratings. In fact, there have been over 4,000 monitored facilities in which ratings have been reduced for various reasons since January 2009 and the cumulative change of ratings for these facilities has been about 9%. These facilities represent about half of all facilities in PJM. This reduced margin combined with increased transmission outages decreases the likelihood and quantity of any excess congestion collection with which to account for underfunding on constraints near the PJM borders. The below table shows the number of facilities since calendar year 2007 for which Transmission Owners have implemented reductions in capability limits. As is reflected, the number of facilities which have had rating reductions is almost three times larger in 2010 than in 2007, and in 2011 the number is over four times larger than in 2007. The number of facility de-ratings has drastically increased as Transmission Owners‟ calculations have become more stringent per NERC or other requirements. Before the recent FTR revenue inadequacies, the system had more margin and less utilized capability and any negative balancing congestion was covered by excess congestion on other facilities.

Table 6: PJM Historical Facility Rating Reductions

Year	PJM facilities with rating reductions
2007	504
2008	471
2009	615
2010	1490
2011	2041

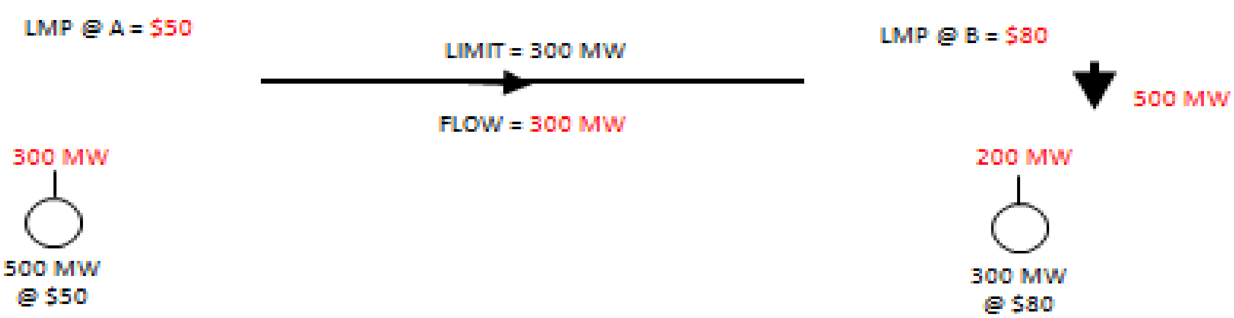
Reduction in ratings can happen for various reasons and it is the reduction in ratings that are not captured in the Day-ahead Energy Market but occur in the Real-time Energy Market that will contribute to negative balancing congestion. Additionally, reductions in ratings after a scheduled FTR Auction has cleared can create an inadequacy from shortfalls in the Day-ahead Energy Market because the FTR Auction would have been modeled and cleared using the higher rating.

The following example demonstrates how a reduction in ratings in the Real-time Energy Market that was not modeled in the Day-ahead Energy Market will create negative balancing congestion.

Example 2: Negative Balancing Congestion caused by rating reduction

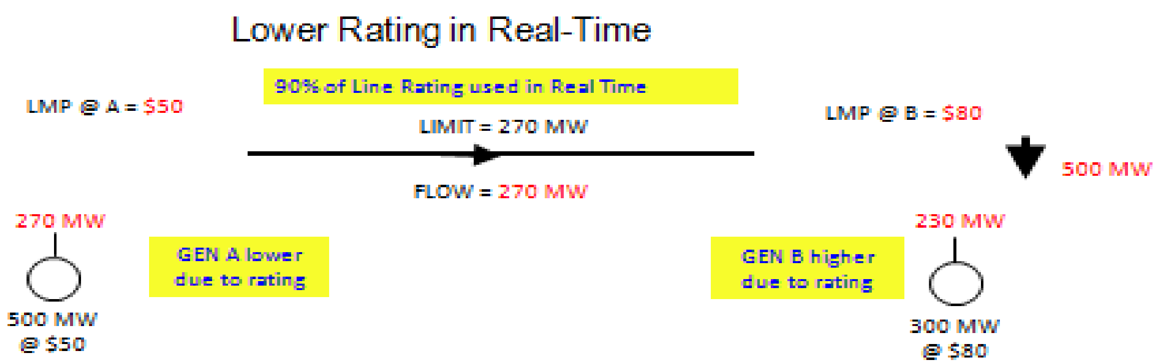
The below diagram shows a simple Day-ahead Energy Market one bus system in which the flow is equal to the limit and the total congestion is equal to $9000. This total congestion value should be used to fund FTRs but as is shown in the next diagram a reduction in the rating in the Real-time Energy Market creates negative balancing congestion.

Day Ahead with Line at Full Rating



DAY AHEAD	A	B	TOTAL
Gen MW	300 MW	200 MW	500 MW
Gross Gen Rev	$15,000	$16,000	$31,000
Load MW	0 MW	500 MW	500 MW
Load Payment	$0	$40,000	$40,000
Congestion Charge	--	--	$9,000

The same day-ahead one bus system is now represented in Real-time Energy Market, but now the limit on this bus has been reduced due to reasons such as a temperature change, NERC requirement, or other unforeseen situations. Notice now that the generation pattern shifts and creates a delta between day ahead and real-time and there is now a negative balancing congestion charge of negative $900 which will subtract from the $9000 day-ahead congestion dollars used to fund FTRs.



BALANCING	A	B	TOTAL
Gen MW DELTA	-30 MW	30 MW	0 MW
Gross Gen Rev	-$1,500	$2,400	$900
Load MW DELTA	0 MW	0 MW	0 MW
Load Payment	$0	$0	$0
Congestion Charge	--	--	-$900

There are many internal PJM constraints which have recently caused larger FTR revenue inadequacies than were historically observed because of the more restrictive system capability due to transmission outages and de-ratings. Many of these internal constraints have historically been neutral or positive contributors to FTR revenue adequacy. The below table shows the significant PJM internal facilities on which congestion has historically been a positive contributor to FTR revenue adequacy but more recently have become negative contributors due to restricted system capability.

Table 7: Internal Transmission Facilities with Diminished FTR Revenue Adequacy

Facility	2010 FTR Revenue Adequacy	2011 FTR Revenue Adequacy	Delta in FTR Revenue Adequacy
Dooms 500/230 KV Transformer	$750,624	-$11,905,350	-$12,655,974
Limerick 500/230 KV Transformer	$4,031,245	-$1,242,239	-$5,273,484
Bedington 500/138 KV Transformer	$6,941	-$4,085,940	-$4,092,881
Charlottesville - Gordonsville (2054) 230 KV Line	$458,674	-$2,038,072	-$2,496,747
Cromby 230/69 KV Transformer	$30,308	-$2,398,394	-$2,428,702
Dickerson - Pleasant View 230 KV Line	$1,282,206	-$214,079	-$1,496,285
Eddington - Holmesburg Tap 230 KV Line	$24,182	-$1,450,221	-$1,474,403
Kearny - Roseland 230 KV Line	$19,469	-$1,122,983	-$1,142,452
Kanawha River 345/138 KV transformer	$1,005,261	-$78,690	-$1,083,951
Bristers - Ox 500 KV line	$536,307	-$512,479	-$1,048,786
Howard - Pumphrey 230 KV Line	$216,088	-$808,270	-$1,024,358
Keystone - Shelocta 230 KV Line	$770,168	-$221,934	-$992,102
Bergen - North Bergen 230 KV Line	$40,692	-$766,067	-$806,759
Corner - Muskingum 138 KV Line	$142,421	-$461,985	-$604,405
Bryn Mawr - Plymouth Meeting 230 KV Line	$6,098	-$598,113	-$604,211
Edinburg 138/115 KV Line	$282,296	-$294,422	-$576,718
Waneeta - Wayne 230 KV Line	$11	-$518,083	-$518,094
Belmont 500/138 KV Transformer	$199,736	-$294,840	-$494,576

E. Loop Flow

Loop flow, or more specifically non-PJM flows on PJM facilities or on non-PJM facilities that affect PJM operations such as PJM-Midwest ISO coordinated facilities, have emerged as a significant factor in FTR shortfalls. PJM models a loop flow assumption in the ARR/FTR allocation and auction processes. However, loop flow in excess of that which is modeled in these analyses causes FTR shortfalls by consuming transmission capability that had been previously allocated to FTRs, effectively causing FTRs to be over-allocated and incapable of being fully supported by day-ahead and real-time system capability. Just as outages can diminish the transmission capability available to accommodate day-ahead and real-time power deliveries consistent with FTRs and result in FTR revenue shortfalls, loop flows can also diminish transmission capability and result in FTR shortfalls.

Because border facilities are more tightly coupled to external systems than are more internal facilities located deeper within the PJM system, facilities at or near the PJM border are generally much more susceptible to loop flow and their negative effects on FTR funding. The following table lists the key results of a statistical analysis of external generators response factors (DFAX) on facilities that bound in real-time operations over a heavily-congested period (July 21-24, 2011).

Table 8: External Generator response factors on congested facilities (July 21-24, 2011)

Facility Impacts of External Generators

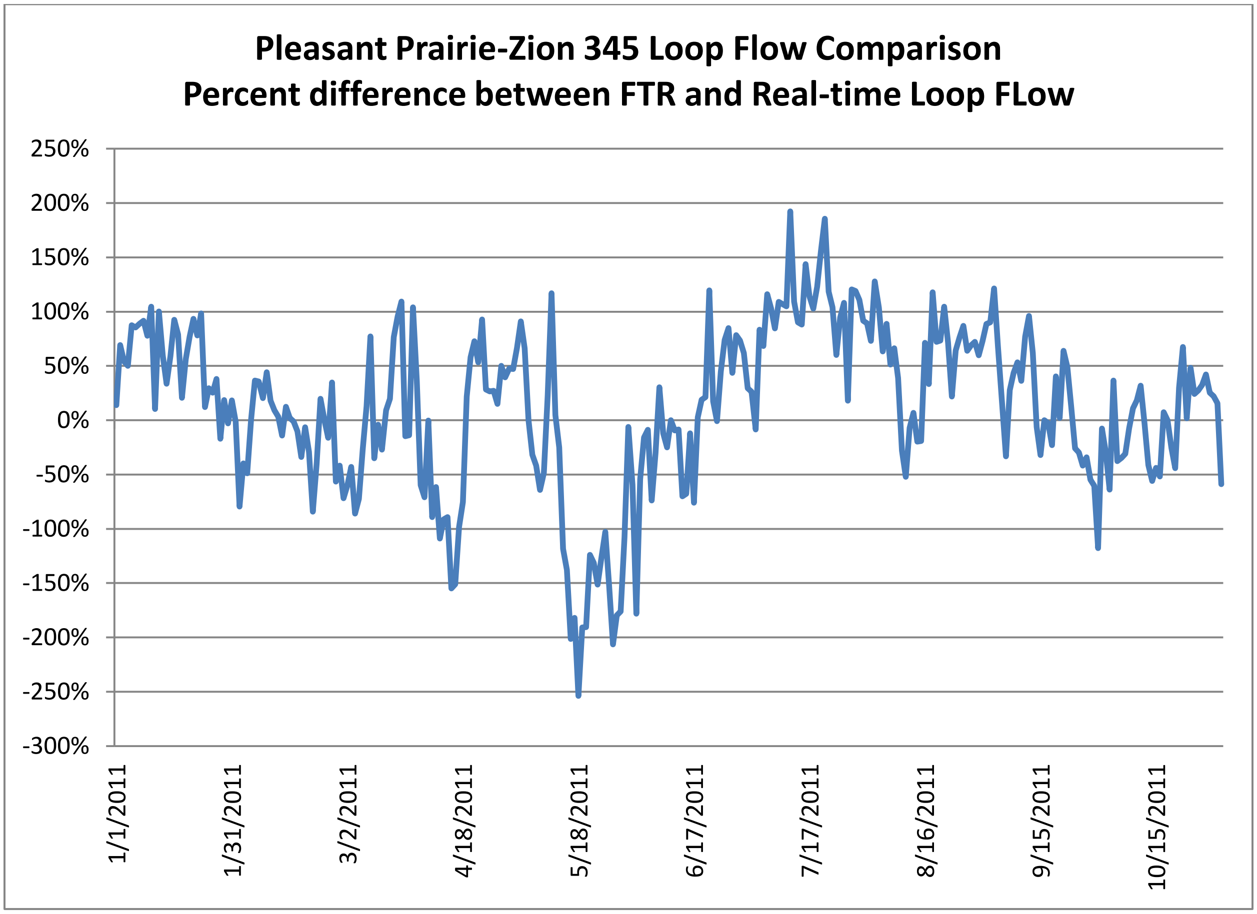
Facility	Description	DFAX Max	DFAX Mean	Standard Dev
Pleasant Prairie-Zion 345	MISO Flowgate @ PJM/MISO Wisc. Border	83%	9%	22%
Arcadian-Pleasant Prairie 345	MISO Flowgate @ PJM/MISO Wisc. Border	58%	6%	15%
8012 345 kv line	PJM Line near PJM/MISO Border	36%	1%	6%
Kenosha-Lakeview 138	MISO Flowgate @ PJM/MISO Wisc. Border	30%	2%	6%
Lakeview-Zion 138	MISO Flowgate @ PJM/MISO Wisc. Border	30%	2%	6%
Rising 345/138	MISO Flowgate @ PJM/MISO Border	20%	1%	3%
Michigan City-Laporte 138	MISO Flowgate @ PJM/MISO Mich. Border	16%	1%	3%
Clover 500/230	PJM Transformer @ PJM/NC Border	14%	4%	3%
Cloverdale-Lexington 500	Internal PJM	11%	7%	3%
Cloverdale 765/345	Internal PJM	10%	5%	3%
Graceton-Cooper 230	Internal PJM	9%	-2%	2%
15503 345 kV line	PJM Flowgate @ PJM/MISO Iowa Border	5%	-4%	12%
Muskingham-Waterford 345	Internal PJM	2%	-4%	4%
15502 345 kV line	PJM Flowgate near PJM/MISO Iowa Border	2%	-3%	8%
Eddystone 230/115	Internal PJM	0%	0%	0%
Talbert-Trappe 69	Internal PJM	0%	0%	0%

As shown, facilities near the western PJM/Midwest ISO border, especially along the PJM/Midwest ISO Wisconsin border, are most impacted by external generation, with response factors as high as 83% on Pleasant Prairie-Zion, meaning that some external generators will place more of their power onto the PJM system than their own regional grid. On the other end of the spectrum is Talbert-Trappe, an electrically isolated 69 kV line located on the Delmarva Peninsula that is completely unaffected by loop flows. The top seven facilities most affected by external deliveries were at or near the PJM/Midwest ISO border and six of them were Midwest ISO flowgates. Internal facilities that are more affected by loop flow tend to be higher voltage facilities that offer a low impedance path for bulk power transfers such as Cloverdale-Lexington 500 and Cloverdale765/500, both along the main southern west-to-east, trans-Allegheny path, while border facilities are impacted more because of their electrical proximity to external systems as evidenced by the appearance of Kenosha-Lakeview 138, Lakeview-Zion 138, and Michigan City-LaPorte 138, all lower voltage, relatively higher impedance facilities.

Loop flows are non-compensatory flows on PJM facilities caused by non-PJM systems‟ power deliveries to their own or other non-PJM systems‟ load that consumes PJM transmission capability. As there often is little or no visibility into these deliveries, by their nature they cannot be predicted easily if at all, nor can their impact on PJM facilities. The definition of loop flow can be expanded to include all flows that cannot be easily predicted and not just those due to non-PJM systems, whether due to external or internal causes, such as intermittent generating resources like wind power.

The figure below shows the erratic nature of loop flow and the portion of capability consumed by loop flow on the Pleasant Prairie-Zion 345 KV market to market flowgate. Loop flow varies between +200% and -250% and consumes as much as 30% of the facility‟s capability.

Figure 9: External World Flow Variation on Congested Facility Located near PJM Border



6. Options to address FTR Underfunding

PJM has identified several options to address the FTR underfunding issue. These options have been provided in a separate document entitled "PJM Options to Address FTR underfunding" located on the PJM web site at http://pjm.com/documents/reports.aspx. Additionally, in its own separate document, PJM‟s Independent Market Monitor (IMM) has also proposed its own options to address the FTR underfunding issue. PJM has posted a copy of this document on the above-referenced PJM web page as well.

7. Monitoring Analytics Comments

The Independent Market Monitor for PJM, Monitoring Analytics, has provided a data report that is included as Appendix B of this document.

Appendix A: FTR Task Force

In March of 2011 the PJM FTR Task Force was created by PJM members[31]. The responsibility of the FTR Task force was to identify specific causes of FTR Revenue Inadequacy, identify discrepancies between the modeling of the Day-ahead, FTR, and Real-Time Markets, explore and identify improvements that can be made to the annual modeling to minimize the risk of underfunding while maximizing opportunity for ARR and FTR availability, and explore alternative methods of funding FTR congestion revenue and shortfalls. These responsibilities were accomplished through several phases including education, investigation, proposal development, and consensus resolution.

There were ten FTR Task Force Meetings held form April 13, 2011 through October 21, 2011. The Education phase which was mainly held during the early meetings of the task force involved a detailed explanation and tutorial of how the FTR markets are conducted, model inputs to the FTR Auctions, processes involved in ARR Allocations and FTR Auctions, FTR funding, and Day-ahead and Real-time contribution to FTR funding. This educational phase continued as necessary throughout all FTR Task Force meetings.

The next phase was the investigation phase in which the group investigated the sources of FTR payouts, the main causes of FTR Revenue inadequacies, and the gaps in processes. The group was able to identify several process improvements that could be utilized to improve the modeling and reduce the risk associated with FTR Revenue Inadequacy. There was also a rule change associated with zero cost FTRs which was already expedited through the stakeholder process and has since been approved by the Commission.

The Design Matrix was next developed after many proposals were made by the membership. These proposals were divided into several design criteria components for Process Improvements, General Auction Rule Changes, Annual, Annual Outages, Monthly Outages, Long Term Outages, and Funding. Next, the design matrix was used to develop several initial packages submitted by the membership and PJM. The result was 23 packages in which a straw poll was taken to gage the interest from members. The result of this initial poll was a reduction of the number of packages to 16. These 16 packages were then polled using several methods along with a poll on each of the individual components of the deign matrix. The result of these polls was used in the development of the final three packages that were presented to the FTR Task Force parent Committee, the Markets Implementation Committee. In addition, two more

[31] *See* materials referenced *supra* note 29.

proposals were added during the December 13, 2012 Markets Implementation Committee meeting.

The description of the final five proposals is described below. PJM also produced a FTRTF Proposal Alternative Report which provides a summary of the task force, proposal details, a comparative summary, and links to relevant documents.[32]

Proposal 1 was a package that consisted of minor changes associated with process improvements and one rule change. This was known as package 1 in the FTR Task Force list of packages. The process improvements included enhanced notification of switching or special operating procedures, increased transparency and description of actual transmission outages associated with circuit breaker or disconnect switch status changes, and an increased awareness and opportunity to model shorter duration transmission outages in monthly auctions that could cause revenue inadequacy. These process improvements have already been initiated and are included in all the proposals. The one rule change which has already been approved by PJM Membership and the Commission is known as the zero cost rule change. It involves not allowing bids to clear where the clearing price equals zero and there are no binding constraints in the auction period on which the FTR path sensitivity is non-zero.

Proposal 2 was a package that consisted of all items that were part of proposal 1 with the addition of several other elements. This was known as package 27 in the FTR Task Force list of packages. The additional elements included Long Term Auction capability reduction, allocation of Residual ARRs associated with Annual ARR stage 1 proration, four day monthly auction outage modeling, and change in calculation of hourly and end of planning period uplift charges. The reduction in Long Term Auction capability involved reducing the capability from 100% to 75%. This reduction is in addition to the already reduced capability under existing rules in which the existing Annual ARRs are assumed to be included in the model for all Long Term Auction study years. The allocation of Residual ARRs involved the proration of Annual ARR Allocation Stage 1 amounts that were associated with transmission outages. The Residual ARRs would be effective for the periods when the transmission outage is not scheduled out of service and the total of the annual and Residual ARR MW amounts would be limited to the Load Serving Entities Network Service Peak Load or Firm Point to Point Customers Transmission service. Residual ARR values would be determined from prompt month auction clearing prices. This proposal also included reducing the criteria for modeling outages in the monthly auction from five days to four days. Finally, this proposal involved changing the hourly settlements calculation along with the end of Planning Period uplift charge calculation to be done on an individual FTR level rather than a portfolio level. The current method for calculation allows negative FTR Target

[32] See PJM Presentation, *Market Implementation Committee: Proposal Alternatives Report; FTR Revenue Inadequacy*, (November 1, 2011), available at http://pjm.com/committees-and-groups/task-forces/~/media/committees-groups/task-forces/ftrtf/postings/ftrtf-proposal-alternatives-report.ashx.

Allocations to offset positive FTR Target Allocations within a member"s portfolio and these positive Target Allocations will not be included in determination of hourly percentage payout and end of planning year uplift charge. The change would not allow negative FTR Target Allocations to offset positive Target Allocations and all FTR positive Target Allocation paths would be included in the hourly and end of Planning Period uplift calculation.

Proposal 3 was a package that consisted of all items that were part of proposal 1 with the addition of a few other elements. This was known as package 28 in the FTR Task Force list of packages. The additional elements included four day monthly auction outage modeling, distribution of any planning period year end excess revenues to zones prorated in Stage 1 in which a modeled outage caused proration, and use of Marginal Loss Surplus Credits to cover revenue inadequacies up to 95% related to transmission outages. The four day monthly auction outage modeling involves changing the criteria for modeling outages in the monthly auction from five days to four days. Proposal 3 also involved changing the end of year excess distribution to include available excess to be allocated to ARR holders who had ARRs prorated in stage 1 of the Annual ARR Allocation due a modeled transmission outage. This distribution would be only for those whom have not received ARRs up to their Network Service Peak Load or Firm Transmission Service. The value for this allocation will be equivalent to the Annual ARRs which is based on the Annual FTR Auction clearing prices. Finally, this proposal involved changing the distribution of Marginal Loss Credits if the FTR revenue inadequacy for the planning period is less than 95%. If the FTR revenue inadequacy is less than 95% for the planning period than funds would be taken from the Marginal Loss Surplus Credits to restore the funding to 95%. The funds to be taken from the Marginal Loss Surplus Credits would be limited to fund FTR revenue inadequacies associated with transmission outages.

Proposal 4 was added during the December 13, 2012 Markets Implementation Committee meeting. This proposal is the same as proposal 1 but with the addition of a rule to exclude balancing real-time congestion from the FTR funding mechanism. This particular proposal was for an implementation date for the 2012/2013 annual Planning Period, to be effective on June 1, 2012.

Proposal 5 was also added at the December 13, 2012 Markets Implementation Committee meeting. This proposal is identical to proposal 4 but with an implementation date for the 2013/2014 annual Planning Period, to be effective on June 1, 2013.

The proposal with the highest votes in favor at the December 13, 2012 Markets Implementation Committee meeting was proposal 1, and this proposal was the main motion for the parent Markets and Reliability Committee. Proposal 2 which had at least a 50% in favor vote was the minor motion for the Markets and Reliability Committee.

Below are the voting results from the December 13, 2012 Markets Implementation Committee meeting.

Table 1: Markets Implementation Committee FTR Task Force Proposal Voting Results

Markets Implementation Committee Proposal	Description	MIC Results
Proposal 1	Process Improvements and approved zero cost rule change only	75.9% in favor
Proposal 2	Proposal 1 plus reduced Long term auction capability, 4 day monthly outage modeling, Residual ARRs, and change in uplift calculation	63.3% in favor
Proposal 3	Proposal 2 plus 4 day monthly outage modeling and change in Marginal Loss allocation.	29.9% in favor
Proposal 4	Proposal 3 plus removal on Balancing Congestion from FTR bucket. Implementation for 12/13 planning period.	46% in favor
Proposal 5	Proposal 4 plus removal on Balancing Congestion from FTR bucket. Implementation for 13/14 planning period.	40% in favor

The Markets and Reliability Committee voted on proposal 1 which was the main motion at its January 26, 2012 meeting. This proposal passed and was next voted on at the Members Committee meeting on February 23, 2012. Proposal 1 originally failed at the Members Committee with a sector-weighted vote in favor of 2.95.[33] Proposal 2 was then voted on and also failed, with a sector-weighted vote of 3.24 in favor. Finally,

[33] Requirements for passing at the Members Committee level is a sector weighted vote of at least 2/3, or 3.33, in favor.

the membership voted again on Proposal 1 which passed by acclamation with two objections and five abstentions. Therefore, the result of the PJM committee process was a membership majority of at least 2/3 for Proposal 1 which consisted only of process improvements and the already approved zero cost rule change.

Appendix B: Monitoring Analytics FTR Facts Related to FTR Report

Introduction

This report compares the quantity and price results of the first three rounds of the Annual FTR Auction for planning periods 2011 to 2012 and 2012 to 2013. Data are available for only the first three rounds.

Volume

Table 1 and Table 2 show the Annual FTR Auction volume for each planning period.

Table 1 2012 to 2013 planning period Annual FTR Auction volume (MW)

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	58,119	277,561	74,413	26.8%	203,148	73.2%
		Prevailing Flow	144,152	991,159	141,430	14.3%	849,729	85.7%
		Total	202,271	1,268,720	215,843	17.0%	1,052,878	83.0%
	Options	Counter Flow	128	8,922	-	0.0%	8,922	100.0%
		Prevailing Flow	21,982	612,862	29,380	4.8%	583,482	95.2%
		Total	22,110	621,784	29,380	4.7%	592,404	95.3%
	Total	Counter Flow	58,247	286,483	74,413	26.0%	212,070	74.0%
		Prevailing Flow	166,134	1,604,022	170,811	10.6%	1,433,211	89.4%
		Total	224,381	1,890,505	245,223	13.0%	1,645,282	87.0%
Self-scheduled bids	Obligations	Counter Flow	194	1,214	1,214	100.0%	-	0.0%
		Prevailing Flow	4,693	30,074	30,074	100.0%	-	0.0%
		Total	4,887	31,287	31,287	100.0%	-	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	58,313	278,775	75,626	27.1%	203,148	72.9%
		Prevailing Flow	148,845	1,021,233	171,504	16.8%	849,729	83.2%
		Total	207,158	1,300,008	247,130	19.0%	1,052,878	81.0%
	Options	Counter Flow	128	8,922	-	0.0%	8,922	100.0%
		Prevailing Flow	21,982	612,862	29,380	4.8%	583,482	95.2%
		Total	22,110	621,784	29,380	4.7%	592,404	95.3%
	Total	Counter Flow	58,441	287,697	75,626	26.3%	212,070	73.7%
		Prevailing Flow	170,827	1,634,095	200,884	12.3%	1,433,211	87.7%
		Total	229,268	1,921,792	276,510	14.4%	1,645,282	85.6%
Sell offers	Obligations	Counter Flow	23,666	80,658	6,597	8.2%	74,061	91.8%
		Prevailing Flow	38,175	135,547	13,192	9.7%	122,355	90.3%
		Total	61,841	216,205	19,789	9.2%	196,415	90.8%
	Options	Counter Flow	-	-	-	-	-	-
		Prevailing Flow	975	9,763	131	1.3%	9,632	98.7%
		Total	975	9,763	131	1.3%	9,632	98.7%
	Total	Counter Flow	23,666	80,658	6,597	8.2%	74,061	91.8%
		Prevailing Flow	39,150	145,310	13,324	9.2%	131,987	90.8%
		Total	62,816	225,968	19,921	8.8%	206,047	91.2%

Table 2 2011 to 2012 planning period Annual FTR Auction volume (MW)

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	70,652	309,376	86,157	27.8%	223,218	72.2%
		Prevailing Flow	222,933	1,304,069	129,296	9.9%	1,174,773	90.1%
		Total	293,585	1,613,445	215,453	13.4%	1,397,991	86.6%
	Options	Counter Flow	150	12,417	8,017	64.6%	4,400	35.4%
		Prevailing Flow	22,790	843,105	26,323	3.1%	816,781	96.9%
		Total	22,940	855,522	34,341	4.0%	821,181	96.0%
	Total	Counter Flow	70,802	321,793	94,175	29.3%	227,618	70.7%
		Prevailing Flow	245,723	2,147,173	155,619	7.2%	1,991,554	92.8%
		Total	316,525	2,468,966	249,794	10.1%	2,219,173	89.9%
Self-scheduled bids	Obligations	Counter Flow	187	959	959	100.0%	-	0.0%
		Prevailing Flow	7,622	33,554	33,554	100.0%	-	0.0%
		Total	7,809	34,513	34,513	100.0%	-	0.0%
Buy and self-scheduled bids	Obligations	Counter Flow	70,839	310,335	87,117	28.1%	223,218	71.9%
		Prevailing Flow	230,555	1,337,623	162,850	12.2%	1,174,773	87.8%
		Total	301,394	1,647,957	249,966	15.2%	1,397,991	84.8%
	Options	Counter Flow	150	12,417	8,017	64.6%	4,400	35.4%
		Prevailing Flow	22,790	843,105	26,323	3.1%	816,781	96.9%
		Total	22,940	855,522	34,341	4.0%	821,181	96.0%
	Total	Counter Flow	70,989	322,752	95,134	29.5%	227,618	70.5%
		Prevailing Flow	253,345	2,180,727	189,173	8.7%	1,991,554	91.3%
		Total	324,334	2,503,479	284,307	11.4%	2,219,173	88.6%
Sell offers	Obligations	Counter Flow	21,204	83,657	3,578	4.3%	80,079	95.7%
		Prevailing Flow	33,947	140,666	17,106	12.2%	123,561	87.8%
		Total	55,151	224,323	20,684	9.2%	203,640	90.8%
	Options	Counter Flow	25	3,800	-	0.0%	3,800	100.0%
		Prevailing Flow	324	4,413	95	2.2%	4,318	97.8%
		Total	349	8,213	95	1.2%	8,118	98.8%
	Total	Counter Flow	21,229	87,457	3,578	4.1%	83,879	95.9%
		Prevailing Flow	34,271	145,080	17,201	11.9%	127,879	88.1%
		Total	55,500	232,537	20,778	8.9%	211,758	91.1%

Volume Changes

Table 3 and Table 4 show the differences in the volumes requested and cleared from the 2011 to 2012, to the 2012 to 2013 planning periods. While demand for FTRs is down substantially, the decrease in the volume of FTRs clearing the auction is much smaller. There was a decrease of 31 percent in FTR requested buy bids from the first three rounds of 2011 to 2012 planning period to the first three rounds of the 2012 to 2013 planning period of 554,908 MW. The total volume of buy and self scheduled requests decreased 23.2 percent, while the cleared volume decreased only 2.7 percent.

Table 3 Difference in volume between first three rounds of the 2011 to 2012 and 2012 to 2013 planning period

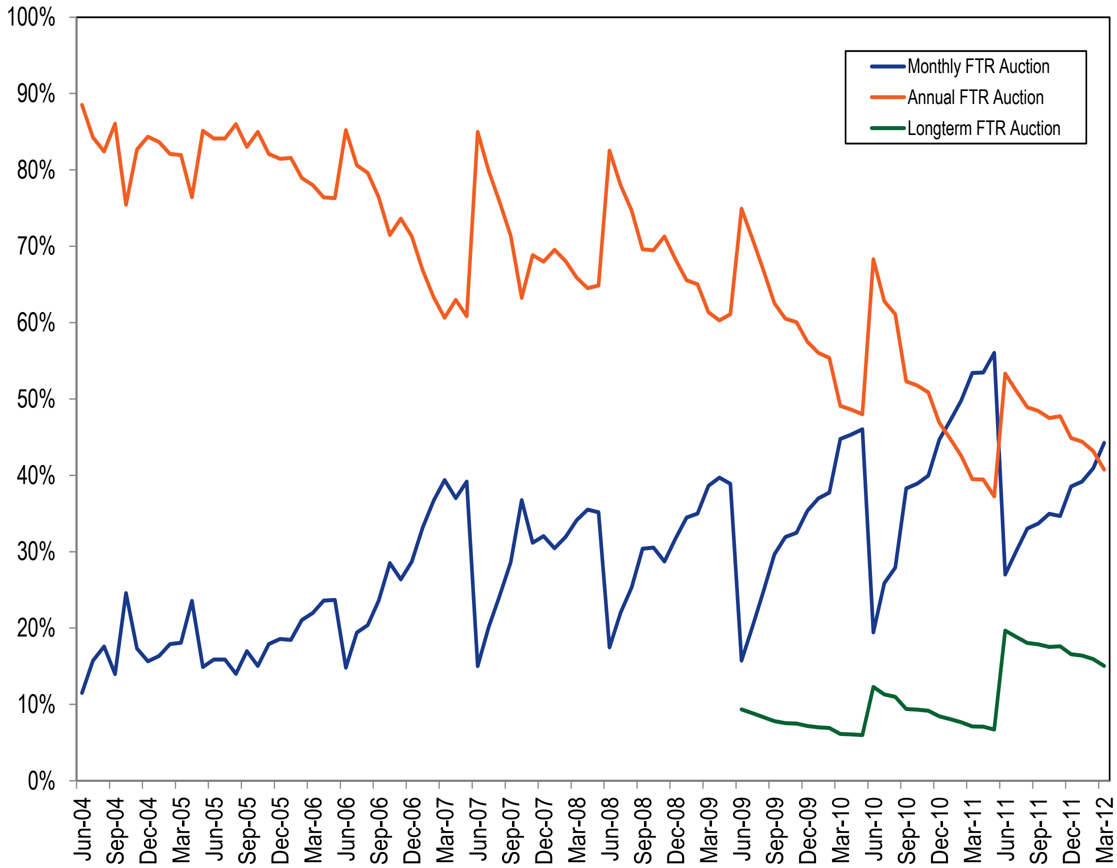
Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)
Buy	Obligation	Counterflow	(12,533)	(31,814)	(31,814)
		Prevailing Flow	(78,781)	(312,910)	12,134
	Option	Counterflow	(22)	(3,495)	(8,017)
		Prevailing Flow	(808)	(230,242)	3,057
Buy+SelfScheduled	Obligation	Counterflow	(12,526)	(31,560)	(11,490)
		Prevailing Flow	(81,710)	(316,390)	8,654
	Option	Counterflow	(22)	(3,495)	(8,017)
		Prevailing Flow	(808)	(230,242)	3,057
	Total	Counterflow	(12,548)	(35,055)	(19,507)
		Prevailing Flow	(82,518)	(546,632)	11,711
		Total	(95,066)	(581,687)	(7,796)
SelfScheduled	Obligation	Counterflow	7	255	255
		Prevailing Flow	(2,929)	(3,480)	(3,480)
Sell	Obligation	Counterflow	2,462	(2,999)	3,019
		Prevailing Flow	4,228	(5,119)	(3,913)
	Option	Counterflow	(25)	(3,800)	-
		Prevailing Flow	651	5,350	36
	Total	Counterflow	2,437	(6,799)	3,019
		Prevailing Flow	4,879	231	(3,877)
		Total	7,316	(6,569)	(858)

Table 4 Percent difference between first three rounds of the 2011 to 2012 and 2012 to 2013 planning periods

Trade Type	Hedge Type	FTR Direction	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)
Buy	Obligation	Counterflow	-17.7%	-10.3%	-36.9%
		Prevailing Flow	-35.3%	-24.0%	9.4%
	Option	Counterflow	-14.7%	-28.1%	-100.0%
		Prevailing Flow	-3.5%	-27.3%	11.6%
Buy+SelfScheduled	Obligation	Counterflow	-17.7%	-10.2%	-13.2%
		Prevailing Flow	-35.4%	-23.7%	5.3%
	Option	Counterflow	-14.7%	-28.1%	-100.0%
		Prevailing Flow	-3.5%	-27.3%	11.6%
	Total	Counterflow	-17.7%	-10.9%	-20.5%
		Prevailing Flow	-32.6%	-25.1%	6.2%
		Total	-29.3%	-23.2%	-2.7%
SelfScheduled	Obligation	Counterflow	3.7%	26.5%	26.5%
		Prevailing Flow	-38.4%	-10.4%	-10.4%
Sell	Obligation	Counterflow	11.6%	-3.6%	84.4%
		Prevailing Flow	12.5%	-3.6%	-22.9%
	Option	Counterflow	NA	NA	NA
		Prevailing Flow	200.9%	121.2%	38.4%
	Total	Counterflow	11.5%	-7.8%	84.4%
		Prevailing Flow	14.2%	0.2%	-22.5%
		Total	13.2%	-2.8%	-4.1%

Figure 1 shows the cleared volume of buy and sell bids for each FTR Auction type as a percentage of total FTR volume by calendar month. Annual and Long Term FTR Auctions are treated as contributing a constant volume for the planning period to each calendar month‟s total volume for their respective planning periods. Long Term FTR Auctions are reported in the appropriate planning periods depending on the period indicated in the bid. For example, a bid for the second year in the 2009 to 2013 Long Term FTR Auction applies only to each calendar month in the 2010 to 2011 planning period. Figure 1 shows that the cleared volume in the Annual FTR Auction has been steadily decreasing, while the cleared volume from the Monthly Balance of Planning Period Auctions has been increasing.

Figure 1 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through March 2012



Price

Table 5 and Table 6 show the cleared, weighted average prices for the first three rounds of the 2012 to 2013 and 2011 to 2012 Annual FTR Auctions.

Table 5 First three rounds of the Annual FTR Auction weighted average cleared prices (Dollars per MW): Planning period 2012 to 2013

Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.18)	($0.38)	($0.21)	($0.28)
		Prevailing Flow	$0.52	$0.64	$0.42	$0.53
		Total	$0.38	$0.31	$0.18	$0.26
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.64	$0.35	$0.16	$0.25
		Total	$0.64	$0.35	$0.16	$0.25
Self-scheduled bids	Obligations	Counter Flow	($0.27)	NA	NA	($0.27)
		Prevailing Flow	$0.69	NA	NA	$0.69
		Total	$0.65	NA	NA	$0.65
Buy and self-scheduled bids	Obligations	Counter Flow	($0.21)	($0.38)	($0.21)	($0.28)
		Prevailing Flow	$0.64	$0.64	$0.42	$0.57
		Total	$0.57	$0.31	$0.18	$0.34
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.64	$0.35	$0.16	$0.25
		Total	$0.64	$0.35	$0.16	$0.25
Sell offers	Obligations	Counter Flow	($0.53)	($0.40)	($0.32)	($0.38)
		Prevailing Flow	$0.29	$0.48	$0.28	$0.39
		Total	$0.06	$0.29	$0.10	$0.19
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$0.22	$0.18	$0.21
		Total	$0.00	$0.22	$0.18	$0.21

Table 6 First three rounds of the Annual FTR Auction weighted average cleared prices (Dollars per MW): Planning period 2011 to 2012

Trade Type	Hedge Type	FTR Direction	24-Hour	On Peak	Off Peak	All
Buy bids	Obligations	Counter Flow	($0.77)	($0.50)	($0.38)	($0.47)
		Prevailing Flow	$0.99	$0.88	$0.69	$0.82
		Total	$0.61	$0.47	$0.32	$0.42
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.33	$0.16	$0.10	$0.13
		Total	$0.33	$0.16	$0.10	$0.13
Self-scheduled bids	Obligations	Counter Flow	($0.10)	NA	NA	($0.10)
		Prevailing Flow	$1.22	NA	NA	$1.22
		Total	$1.18	NA	NA	$1.18
Buy and self-scheduled bids	Obligations	Counter Flow	($0.64)	($0.50)	($0.38)	($0.46)
		Prevailing Flow	$1.15	$0.88	$0.69	$0.94
		Total	$0.98	$0.47	$0.32	$0.60
	Options	Counter Flow	$0.00	$0.00	$0.00	$0.00
		Prevailing Flow	$0.33	$0.16	$0.10	$0.13
		Total	$0.33	$0.16	$0.10	$0.13
Sell offers	Obligations	Counter Flow	($1.96)	($0.55)	($0.47)	($0.61)
		Prevailing Flow	$0.72	$0.73	$0.44	$0.60
		Total	($0.07)	$0.56	$0.27	$0.41
	Options	Counter Flow	NA	NA	NA	NA
		Prevailing Flow	$0.00	$1.71	$0.70	$0.84
		Total	$0.00	$1.71	$0.70	$0.84

Price Changes

Table 7 and Table 8 show the differences in the cleared, weighted average prices between the first three rounds of the 2012 to 2013 and 2011 to 2012 Annual FTR Auction. In general, prices of prevailing flow FTRs are down, with the exception of prevailing flow options, for which prices are up $0.12 over the previous planning period. The price of self-scheduled counter flow obligations are up $0.17 (171.5 percent) over the same rounds of the previous planning period. In Table 7 a positive change in a counterflow FTR price means that the participant receives less to take the FTR. A negative change in a prevailing flow FTR price means that the participant paid less to purchase the FTR.

Table 7 Difference in price between first three rounds of the 2011 to 2012 and 2012 to 2013 planning period

Trade Type	Hedge Type	FTR Direction	24 Hour	On Peak	Off Peak	All
Buy	Obligation	Counterflow	$0.59	$0.12	$0.17	$0.19
		Prevailing Flow	($0.47)	($0.24)	($0.27)	($0.29)
		Total	($0.23)	($0.15)	($0.14)	($0.16)
	Option	Prevailing Flow	$0.31	$0.19	$0.06	$0.12
		Total	$0.31	$0.19	$0.06	$0.12
Buy+SelfScheduled	Obligation	Counterflow	$0.43	$0.12	$0.17	$0.18
		Prevailing Flow	($0.50)	($0.24)	($0.27)	($0.36)
		Total	($0.41)	($0.15)	($0.14)	($0.25)
	Option	Prevailing Flow	$0.31	$0.19	$0.06	$0.12
		Total	$0.31	$0.19	$0.06	$0.12
SelfScheduled	Obligation	Counterflow	($0.17)	NA	NA	($0.17)
		Prevailing Flow	($0.53)	NA	NA	($0.53)
		Total	($0.53)	NA	NA	($0.53)
Sell	Obligation	Counterflow	$1.43	$0.16	$0.15	$0.23
		Prevailing Flow	($0.43)	($0.25)	($0.16)	($0.21)
		Total	$0.13	($0.28)	($0.18)	($0.22)
	Option	Prevailing Flow	$0.00	($1.49)	($0.53)	($0.63)
		Total	$0.00	($1.49)	($0.53)	($0.63)

Table 8 Percent difference between first three rounds of the 2011 to 2012 and 2012 to 2013 planning periods

Trade Type	Hedge Type	FTR Direction	24 Hour	On Peak	Off Peak	All
Buy	Obligation	Counterflow	-76.4%	-24.1%	-44.5%	-40.9%
		Prevailing Flow	-47.5%	-27.5%	-39.0%	-35.5%
		Total	-37.0%	-33.1%	-44.5%	-38.9%
	Option	Prevailing Flow	95.1%	119.3%	64.5%	94.5%
		Total	95.1%	119.3%	64.5%	94.5%
Buy+SelfScheduled	Obligation	Counterflow	-67.2%	-24.1%	-44.5%	-26.4%
		Prevailing Flow	-44.0%	-27.5%	-39.0%	-26.0%
		Total	-42.0%	-33.1%	-44.5%	-25.8%
	Option	Prevailing Flow	95.1%	119.3%	64.5%	94.5%
		Total	95.1%	119.3%	64.5%	94.5%
SelfScheduled	Obligation	Counterflow	171.5%	NA	NA	171.5%
		Prevailing Flow	-43.3%	NA	NA	-43.3%
		Total	-44.7%	NA	NA	-44.7%
Sell	Obligation	Counterflow	-73.1%	-28.4%	-31.2%	-37.9%
		Prevailing Flow	-60.0%	-34.6%	-35.9%	-35.6%
		Total	-184.1%	-49.3%	-64.6%	-53.7%
	Option	Prevailing Flow	NA	-87.0%	-74.7%	-176.6%
		Total	NA	-87.0%	-74.7%	-176.6%