Financial Transmission and Auction Revenue Rights

In an LMP market, the lowest cost generation is dispatched to meet the load, but when there are transmission constraints, load pays the high local price for all generation, including the low cost generation serving part of that load. The result is that load pays the correct local price but pays too much in total for energy. In an LMP market, load pays more than generation receives. FTRs are the mechanism for returning those excess payments to load. But the FTR mechanism in PJM does not and cannot return all the excess payments to load. The FTR mechanism in PJM needs a significant redesign in order to achieve that objective.

The FTR mechanism should be a simple accounting method for assigning congestion rights to load. But PJM has had to add increasingly complex rules and regularly intervene in the FTR mechanism because the PJM FTR design has moved further and further from these economic fundamentals. Market participants have profited in various ways from these design flaws and now strongly defend the current design.

When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load, subject to transmission limits. This was true prior to the introduction of LMP markets and continues to be true in LMP markets. Prior to the introduction of LMP markets, payment for the delivery of low cost generation to load was based both on intrazonal generation and intrazonal transmission under cost of service rates, and on contracts with specific remote generation outside the local zone and the associated point to point transmission contracts. In both cases, customers paid for the physical rights associated with the transmission system used to provide for the delivery of low cost generation to load. There was no congestion revenue because customers paid only the actual cost of the low cost generation. Most generation was intrazonal and the transmission system used to deliver the related energy to intrazonal load was also intrazonal.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced, effective April 1, 1999, for the real-time market and June 1, 2000, for the day-ahead and balancing markets. FTRs permitted the loads, which pay for the transmission system, to continue to receive the benefits of access to either local or remote low cost generation by returning congestion to the load.[1] FTRs and the associated congestion revenues were directly provided to load in recognition of the fact that, as a result of LMP, load was required to pay more for low cost generation than is paid to low cost generation. But there was a flaw built in from the very beginning that had no significant impact initially but which was ultimately the source of all the issues with the FTR mechanism. That flaw was the idea that congestion was based on contract paths in a network system rather than a result of the actual operation of the complex network. That flaw was inconsistent with the most basic logic of LMP and the resultant fissure continued to widen. The origin of FTRs was the recognition that the way to hold load harmless from making these excess payments created by the LMP system was to return the excess payments to load. The rights to congestion belong to load. If implemented correctly, FTRs would be the financial equivalent of firm transmission service for load. If implemented correctly, FTRs would be a perfect hedge against congestion for load.

The notion that FTRs exist in order to provide a hedge for generation is a fallacy. In an LMP system, the basic incentive structure for generation derives from the fact that generation is paid the LMP at the generator bus. If generation were to be guaranteed a price at a distant constrained load bus rather than at the generation bus, there would be no incentive for generation to locate where it is needed on the system. In addition, the payment of the price at the generator bus is fundamental to the logic of locational marginal pricing which produces local prices equal to the marginal value of generation at every point. There is no logical or theoretical basis in locational marginal pricing for the assertion that generation at low price nodes is underpaid and should be paid more from congestion dollars. Generation does not pay congestion. Some generation receives a price lower than the system marginal price (SMP) and some generation receives a price greater than SMP but that does not mean

1 See 81 FERC ¶ 61,257 at 62,241 (1997).

that generation is paying congestion. It means that generation is being paid an LMP that is higher or lower than the system load-weighted average LMP. If a generating unit wants, it may enter into an arms length transaction with a willing counter party as a hedge. That is the way hedges work in markets. That is not the way the FTR mechanism works.

In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. FTRs were the mechanism selected in PJM to offset the congestion costs that load pays in an LMP market. Congestion revenues are the source of the funds to pay FTRs. Congestion revenues are assigned to the load that paid them through FTRs.[2] The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load or, more precisely, that the rights to all congestion revenues are assigned to load. In order to do that, congestion must be defined correctly based on the operation of the network and not on arbitrary contract paths.

Effective April 1, 1999, when FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing congestion to load. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). Under the ARR construct, the load still owns the rights to congestion revenue, but the ARR construct allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights to congestion revenue in the FTR auction in exchange for a revenue stream based on the auction clearing prices of the FTRs. Under the ARR construct, the right to all congestion revenues should belong to load. All congestion surplus should be assigned to load. But the actual implementation produces a very different result.

2 See *id.* at 62, 259–62,260 & n. 123.

ARRs were an add on concept, defined based on a misunderstanding of FTRs which had its roots in the assignment of congestion to load using contract paths (generation to load paths) rather than on the calculation of congestion actually paid. The ARR concept as it is currently implemented, does not allow the FTR sellers, load, to establish a selling price, but forces load to accept whatever prices buyers are willing to pay. The revenue from the sale of congestion rights is not even paid in full to ARR holders. So called surplus revenue is paid to FTR holders to ensure payment despite the fact that willing FTR buyers paid the revenues in the auction for the rights to congestion.

The use of generation to load paths rather than the direct calculation of congestion led to an increased divergence between the congestion on the generation to load paths and total congestion. This divergence between actual network use and historic paths was exacerbated as new zones were added with their own historic generation to load paths and as significant numbers of generating units retired and new units were added.[3] Rather than understanding that the divergence resulted from the fact that a path based approach did not correctly calculate congestion in a network system, especially as the system grew significantly, the issue was characterized as the existence of excess capacity on the transmission system. But congestion was never about capacity on the transmission system. Prior to the introduction of ARRs, the so called excess congestion that exceeded the congestion on the defined paths was returned to load. There is no such thing as excess congestion. The overlay of ARRs on the FTR concept did not change the fundamental logic of congestion, but permitted the introduction of a system in which the divergence was formally created between the amount of congestion paid by load and the amount of congestion returned to load. Congestion belongs to the load, by definition. The introduction of ARRs based on a contract path fiction undermined the assignment of all congestion rights to load.

The ARR/FTR design does not serve as an efficient mechanism for returning congestion to load, as a result of an FTR design that was flawed from its introduction and as a result of various distortions added to the design since its

3 For a comprehensive report on capacity retirements and capacity additions in PJM, see: "2020 PJM Generation Capacity and Funding Sources: 2007/2008 through 2021/2022," (September 15, 2020) available at <http://www.monitoringanalytics.com/reports/Reports/2020/Constraint_Based_Congestion_Calculations_20200722.pdf>

introduction. The distortions include the definition of target allocations based on day-ahead congestion only, the failure to assign all FTR auction revenues to ARR holders, differences between modeled and actual system capability, the definition and allocation of surplus, and numerous cross subsidies among participants. The fundamental distortion was the assignment of the rights to congestion revenue based on specific generation to load transmission paths. This approach retained the contract path based view of congestion rooted in physical transmission rights and inconsistent with the role of FTRs in a nodal, network system with locational marginal pricing.

The cumulative offset by ARRs for the 2011/2012 planning period through the first four months of the 2020/2021 planning period, using the rules effective for each planning period, was 75.0 percent. Load has been underpaid by $2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period.

The overall underassignment of congestion to load includes dramatically different results by zone. Load in some zones receives congestion revenues well in excess of the congestion they pay while the reverse is true for other zones.

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy. The design should simply have provided for the return of all congestion revenues to load. Now is a good time to address the issues of the FTR design and to return the design to its original purpose. This would eliminate much of the complexity associated with ARRs and FTRs and eliminate unnecessary controversy about the appropriate recipients of congestion revenues.

The *2020 Quarterly State of the Market Report for PJM: January through September* focuses on the 2020/2021 Monthly Balance of Planning Period FTR Auctions, specifically covering January 1, 2020, through September 30, 2020.

Table 13-1 The FTR auction markets results were competitive

Market Element	Evaluation	Market Design
Market Structure	Competitive	
Participant Behavior	Partially Competitive	
Market Performance	**Competitive**	**Flawed**

- Market structure was evaluated as competitive. The ownership of FTR obligations is unconcentrated for the individual years of the 20/23 Long Term FTR Auction and the 20/21 Annual FTR Auction. The ownership of FTR options is moderately or highly concentrated for every Monthly FTR Auction period and moderately concentrated for the 20/21 Annual FTR Auction. Ownership of FTRs is disproportionately (73.6 percent) by financial participants.
- Participant behavior was evaluated as partially competitive as a result of the behavior of GreenHat Energy, LLC.
- Market performance was evaluated as competitive because it reflected the interaction between buyer behavior and the FTRs that PJM made available for sale. It is not clear, in a competitive market, why FTR purchases by financial entities remain persistently profitable.
- Market design was evaluated as flawed because there are significant and fundamental flaws with the basic ARR/FTR design. The FTR auction market is not actually a market because the sellers have no independent role in the process. The market design is not an efficient or effective way to ensure that the rights to all congestion revenues are assigned to load. ARR holders' rights to congestion revenues are not correctly defined. The path based assignment of congestion rights is inadequate and incorrect. ARR holders cannot determine the price at which they are willing to sell rights to congestion revenue. Ongoing PJM subjective intervention in the FTR market that affects market fundamentals is also an issue.

- The fact that load is not able to define its willingness to sell FTRs or the prices at which it is willing to sell FTRs and the fact that auction surplus, despite resulting from FTR buyers' actual offer prices, is returned to buyers as needed rather than the sellers, means that the FTR design does not actually function as a market and raises questions about the market structure, the market performance and the market design.

Overview

Auction Revenue Rights

Market Structure

- **Residual ARRs.** Residual ARRs are only available on paths prorated in Stage 1 of the annual ARR allocation, are only effective for single, whole months and cannot be self scheduled. Residual ARR clearing prices are based on monthly FTR auction clearing prices. Residual ARRs with negative target allocations are not allocated to participants. Instead they are removed and the model is rerun.

  In the first four months of the 2020/2021 planning period, PJM allocated a total of 16,997.8 MW of residual ARRs with a total target allocation of $3.6 million, up from 11,162.7 MW in the first four months of the 2019/2020 planning period, with a total target allocation of $2.7 million.

- **ARR Reassignment for Retail Load Switching.** There were 13,606 MW of ARRs associated with $78,900 of revenue that were reassigned in the first four months of the 2020/2021 planning period. There were 18,913 MW of ARRs associated with $223,800 of revenue that were reassigned for the same time frame of the 2019/2020 planning period.

Market Performance

- **Revenue Adequacy.** For the first four months of the 2020/2021 planning period, the ARR target allocations, which are based on the nodal price differences from the Annual FTR Auction, were $509.1 million, while PJM collected $670.5 million from the combined Long Term, Annual and Monthly Balance of Planning Period FTR Auctions, making ARRs revenue adequate. The allocation of surplus congestion revenue provides for revenue adequacy for FTRs first, and any remaining revenues at the end of the planning period are allocated to ARR holders. For the 2019/2020 planning period, the ARR target allocations were $752.2 million while PJM collected $982.0 million from the combined Annual and Monthly Balance of Planning Period FTR Auctions.

- **ARRs as an Offset to Congestion.** ARRs have historically not served as an effective way to return all congestion revenues to load. For the first four months of the 2020/2021 planning period, 50.6 percent of total congestion was offset by ARR credit allocations to ARR holders. Congestion payments by load in some zones were more than offset and congestion payments in some zones were less than offset. The goal of the ARR/FTR market design should be to ensure that load has the rights to 100 percent of the congestion revenues. The cumulative offset was 75.0 percent based on the rules that were in place for each planning period. Load has been underpaid by $2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period.

Financial Transmission Rights

Market Structure

- **Monthly Balance of Planning Period FTR Auctions.** The structure of the Monthly Balance of Planning Period FTR Auctions was changed effective with the 2020/2021 planning period. The new structure makes available the FTRs for each remaining month in the planning period. The prior design made available the FTRs for the next three individual months and then any eligible quarters. Beginning in the 2020/2021 planning period any individual remaining calendar month is available for bids or offers. For example, in the June auction June through May are available as individual periods. In the January auction, January through May are available as individual periods.

- **Sell Offers.** In a given auction, market participants can sell FTRs that they have acquired in preceding auctions or preceding rounds of auctions. In the Monthly Balance of Planning Period FTR Auctions for the first four

months of the 2020/2021 planning period, total participant FTR sell offers were 8,033,682 MW.

- **Buy Bids.** The total FTR buy bids from the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2020/2021 planning were 17,505,199 MW.
- **Patterns of Ownership.** For the Monthly Balance of Planning Period Auctions, financial entities purchased 84.5 percent of prevailing flow and 87.1 percent of counter flow FTRs for January through September, 2020. Financial entities owned 74.4 percent of all prevailing and counter flow FTRs, including 67.5 percent of all prevailing flow FTRs and 83.3 percent of all counter flow FTRs during the period from January through September 2020.

Market Behavior

- **FTR Forfeitures.** Under the modified FTR forfeiture rules, total FTR forfeitures were $22.1 million for the period January 19, 2017, through September 30, 2020.
- **Credit.** There were three collateral defaults in the first nine months of 2020 for a total of $34,410. There were 22 payment defaults in the first nine months of 2020 not involving GreenHat Energy, LLC for a total of $31,796. GreenHat Energy accrued payment defaults of $15.6 million in the first nine months of 2020 for a total of $162.6 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.[4] In addition, PJM added the settlement fee and claimant payee funds to the default allocation, resulting in allocations of $12.5 million and $5.0 million for a total of $180.1 million.

Market Performance

- **Volume.** In the first four months of the 2020/2021 planning period, Monthly Balance of Planning Period FTR Auctions cleared 2,720,662 MW (15.5 percent) of FTR buy bids and 1,357,952 MW (16.9 percent) of FTR sell offers. For the first four months of the 2019/2020 planning period, Monthly Balance of Planning Period FTR Auctions cleared 1,588,345 MW (16.6 percent) of FTR buy bids and 832,832 MW (21.5 percent) of FTR sell offers.
- **Price.** The weighted average buy bid cleared FTR price in the Monthly Balance of Planning Period FTR Auctions for all periods of the first four months of the 2020/2021 planning period was $0.14.
- **Revenue.** The Monthly Balance of Planning Period FTR Auctions generated $20.8 million in net revenue for all FTRs of the first four months of the 2020/2021 planning period, down from $27.9 million for the same time period in the 2019/2020 planning period.
- **Revenue Adequacy.** FTRs were paid at 100.0 percent of the target allocation level for the first four months of the 2020/2021 planning period, including the distribution of the current surplus revenue.
- **Profitability.** FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. In the first four months of 2020/2021 planning period, physical entities made $38.0 million profits on FTRs purchased directly (not self scheduled), up from $2.1 million losses for the same time period in the 2019/2020 planning period and financial entities made $98.4 million including GreenHat's losses, up from $5.6 million profits for the same time period in the 2019/2020 planning period.

4 See the *2019 Quarterly State of the Market Report for PJM: January through June* for a more complete explanation of credit issues that occurred in 2019.

Markets Timeline

Any PJM member can participate in the Long Term FTR Auction, the Annual FTR Auction and the Monthly Balance of Planning Period FTR Auctions.

Table 13-2 shows the date of first availability and final closing date for all annual ARR and FTR products.

Table 13-2 Annual FTR product dates

Auction	Initial Open Date	Final Close Date
2021/2024 Long Term	6/2/2020	3/2021
2019/2020 ARR	3/2/2020	4/3/2020
2019/2020 Annual	4/7/2020	5/4/2020

Recommendations

- The MMU recommends that the ARR/FTR design be modified to ensure that the rights to all congestion revenues are assigned to load. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that all historical generation to load paths be eliminated as a basis for assigning ARRs. The MMU recommends that the current design be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. (Priority: High. First reported 2015. Status: Partially adopted.)
- The MMU recommends that the Long Term FTR product be eliminated. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that, if the Long Term FTR product is not eliminated, the Long Term FTR Market be modified so that the supply of prevailing flow FTRs in the Long Term FTR Market is based solely on counter flow offers in the Long Term FTR Market. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, the full capability of the transmission system be allocated as ARRs prior to sale as FTRs. Reductions for outages and increased system capability should be reserved for ARRs rather than sold in the Long Term FTR Auction. (Priority: High. First reported 2017. Status: Not adopted.)
- The MMU recommends that all FTR auction revenue be distributed to ARR holders monthly, regardless of FTR funding levels. (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that, under the current FTR design, all congestion revenue in excess of FTR target allocations be distributed to ARR holders on a monthly basis. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that FTR auction revenues not be used by PJM to buy counter flow FTRs for the purpose of improving FTR payout ratios.[5] (Priority: High. First reported 2015. Status: Not adopted.)
- The MMU recommends that PJM eliminate portfolio netting to eliminate cross subsidies among FTR market participants. (Priority: High. First reported 2012. Status: Not adopted. Rejected by FERC.)
- The MMU recommends that PJM eliminate subsidies to counter flow FTRs by applying the payout ratio to counter flow FTRs in the same way the payout ratio is applied to prevailing flow FTRs. (Priority: High. First reported 2012. Status: Not adopted.)
- The MMU recommends that PJM eliminate geographic cross subsidies. (Priority: High. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM examine the mechanism by which self scheduled FTRs are allocated when load switching among LSEs occurs throughout the planning period. (Priority: Low. First reported 2011. Status: Not adopted.)
- The MMU recommends that PJM improve transmission outage modeling in the FTR auction models, including the use of probabilistic outage modeling. (Priority: Low. First reported 2013. Status: Not adopted.)
- The MMU recommends that PJM reduce FTR sales on paths with persistent overallocation of FTRs, including a clear definition of persistent overallocation and how the reduction will be applied. (Priority: High. First reported 2013. Status: Partially adopted, 2014/2015 planning period.)

5 See "PJM Manual 6: Financial Transmission Rights," Rev. 254 (July 23, 2020).

- The MMU recommends that the FTR portfolio of a defaulted member be canceled rather than liquidated or allowed to settle as a default cost on the membership. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM continue to evaluate the bilateral indemnification rules and any asymmetries they may create. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends that PJM examine the source and sink node combinations available in the FTR market and eliminate generation to generation paths and all other paths that do not represent the delivery of power to load. (Priority: High. First reported 2018. Status: Not adopted.)
- The MMU recommends that the forfeiture amount from the FTR forfeiture rule be based on the correct hourly cost of an FTR, rather than a simple daily price divided by 24. (Priority: High. First reported 2018. Status: Adopted, 2019. Pending at FERC.)
- The MMU recommends that IARRs be eliminated from PJM's tariff, but that if IARRs are not eliminated, IARRs should be subject to the same proration rules that apply to all other ARR rights. (Priority: Low. First reported 2018. Status: Not adopted.)
- The MMU recommends a requirement that the details of all bilateral FTR transactions be reported to PJM. (Priority: High. First reported Q2, 2020. Status: Not adopted.)
- The MMU recommends that PJM enforce the FTR auction bid limits at the parent company level starting immediately. (Priority: High. New recommendation. Status: PJM planning to implement.)

Conclusion

Solutions

The annual ARR allocation should be designed to ensure that the rights to all congestion revenues are assigned to firm transmission service customers, without requiring contract path physical transmission rights that are inconsistent with the network based delivery of power and the actual way congestion is generated in security constrained LMP markets. When there are binding transmission constraints and locational price differences, load pays more for energy than generation is paid to produce that energy. The difference is congestion. As a result, congestion belongs to load and should be returned to load.

The current path based design should be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. The assigned right is to the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load can retain the right to the network congestion or sell the right through auctions.

Issues

If the original PJM FTR approach had been designed to return congestion revenues to load without use of the generation to load paths, and if the distortions subsequently introduced into the FTR design not been added, many of the subsequent issues with the FTR design and complex redesigns would have been avoided. PJM would not have had to repeatedly intervene in the functioning of the FTR system in an effort to meet the artificial and incorrectly defined goal of revenue adequacy.

PJM has persistently and subjectively intervened in the FTR market in order to affect the payments to FTR holders. These interventions are not appropriate. For example, in the 2014/2015, 2015/2016 and 2016/2017 planning periods, PJM significantly reduced the allocation of ARR capacity, and FTRs, in order to guarantee full FTR funding. PJM reduced system capability in the FTR auction model by including more outages, reducing line limits and including additional constraints. PJM's modeling changes resulted in significant reductions in Stage 1B and Stage 2 ARR allocations, a corresponding reduction in the available quantity of FTRs, a reduction in congestion revenues assigned to ARRs, and an associated surplus of congestion revenue relative to FTR target allocations. This also resulted in a significant redistribution of ARRs among ARR holders based on differences in allocations between Stage 1A and Stage 1B ARRs. Starting in the 2017/2018 planning period, with the allocation

of balancing congestion and M2M payments to load rather than FTRs, PJM increased system capability allocated to Stage 1B and Stage 2 ARRs, but continued to conservatively select outages to manage FTR funding levels.

PJM has intervened aggressively in the FTR market since its inception in order to meet various subjective objectives including so called revenue adequacy. PJM should not intervene in the FTR market to subjectively manage FTR funding. PJM should fix the FTR/ARR design and then should let the market work to return congestion to load and to let FTR values reflect actual congestion.

Load should never be required to subsidize payments to FTR holders, regardless of the reason.[6] The FERC order of September 15, 2016, introduced a subsidy to FTR holders at the expense of ARR holders.[7] The order requires PJM to ignore balancing congestion when calculating total congestion dollars available to fund FTRs. As of the 2017/2018 planning period, as a result of the FERC order, balancing congestion and M2M payments are assigned to load, rather than to FTR holders. When combined with the direct assignment of both surplus day-ahead congestion and surplus FTR auction revenues to FTR holders, the Commission's order shifted substantial revenue from load to the holders of FTRs and reduced the ability of load to offset congestion. This approach ignores the fact that loads must pay both day-ahead and balancing congestion, and that congestion is defined, in an accounting sense, to equal the sum of day-ahead and balancing congestion. Eliminating balancing congestion from the FTR revenue calculation requires load to pay twice for congestion. Load pays for the physical transmission system, pays in excess of generator revenues and pays negative balancing congestion again. The result is that load gets back less than total congestion. The fundamental reasons that there has been a significant and persistent difference between day-ahead and balancing congestion include transmission modeling in the FTR auction and the role of UTCs in taking advantage of these modeling differences and creating negative balancing congestion. There was no reason to impose these costs on load.

These changes were made in order to increase the payout to holders of FTRs who are not loads. Increasing the payout to FTR holders at the expense of the load is not a supportable market objective. PJM should implement an FTR design that calculates and assigns congestion rights to load rather than continuing to modify the current design.

Load was made significantly worse off as a result of the changes made to the FTR/ARR process by PJM based on the FERC order of September 15, 2016. ARR revenues were significantly reduced for the 2017/2018 FTR Auction, the first auction under the new rules. ARRs and self scheduled FTRs offset 50.0 percent of total congestion costs for the 2017/2018 planning period rather than the 60.5 percent offset that would have occurred under the prior rules, a difference of $125.8 million.

A subsequent rule change was implemented by PJM that modified the allocation of surplus auction revenue to the benefit of load. Beginning with the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are assigned to FTR holders only up to the point of revenue adequacy, and then distributed to ARR holders.[8] However, under the rules, ARR holders will only be allocated this surplus after full funding of FTRs is accomplished. The new rules do not fully recognize ARR holders' rights to surplus congestion revenue. With this rule in effect for the first four months of the 2020/2021 planning period, ARRs and FTRs offset 50.6 percent of total congestion rather than 50.2 percent.

The complex machinations related to what is termed the overallocation of Stage 1A ARRs are entirely an artificial result of reliance on the contract path model in the assignment of FTRs. For example, there is a reason that transmission is not built to address the Stage 1A overallocation issue. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows.

6 Such subsidies have been suggested repeatedly. See FERC Dockets Nos. EL13-47-000 and EL12-19-000.
7 See 156 FERC ¶ 61,180 (2016), *reh'g denied*, 156 FERC ¶ 61,093 (2017).
8 163 FERC ¶61,165 (2018).

Proposed Design

To address the issues with the current path based ARR/FTR market design, the MMU recommends that the current design be replaced with a network design in which the rights to actual congestion are assigned directly to load by node. The assigned right would be the actual difference between load payments, both day-ahead and balancing, and revenues paid to the generation used to serve that load. The load could retain the right to the network congestion or sell the right through auctions.

With a network assignment of actual congestion, there would be no cross subsidies among rights holders and no over or under allocation of rights relative to actual network market solutions. There would be no revenue shortfalls as congestion payments equal congestion collected. The risk of default would be isolated to the buyer and seller of the right, and any default is not socialized to other right holders. In the case of a defaulting buyer, the rights to the congestion revenues revert to the load. There would be no risk of a network right flipping in value from positive to negative because congestion is always the positive difference between what load pays for energy, and generation is paid for energy that results from transmission constraints.

Under this proposed design, the rights to congestion can be kept by the physical load or the rights to the congestion can be sold in an auction and the proceeds from the sale of the rights would go to the physical load.

The MMU proposal requires the calculation of constraint specific congestion and the calculation of that specific constraint's congestion related charges to each physical load bus downstream of that constraint. Under the MMU proposal, the constraint specific congestion calculated by hour, from both the day-ahead and balancing market would be paid directly to the physical load as a credit against the associated load serving entity's (LSE) energy bill. This right to the congestion is the network based financial transmission right (NFTR) to the physical load at a defined bus, zone or aggregate. The LSE could choose to sell all or a portion of the NFTR and its associated congestion revenue stream through an annual and/or monthly auction or through a bilateral arrangement with a third party.

An NFTR is the right to actual, realized network related congestion that is collected from a specific bus, zone or aggregate. A NFTR is therefore not defined as a fixed MW amount between two points and it is not a realized path specific price spread. A NFTR is defined as the right to total actual network congestion collected from the defined bus, zone or aggregate. Rather than being sold in terms of MW, NFTRs are sold as a fixed proportion of the total actual network congestion that will be returned to the defined bus, zone or aggregate.

Under the MMU proposal a bus, zone or aggregate specific NFTR could be sold as portions of the actual congestion. For example, an LSE could sell 50 percent of its congestion credit for the planning year to a third party. The third party buyer would then be entitled to 50 percent of the congestion that will be credited to that specific bus, zone or aggregate for the planning year. The remaining 50 percent of the congestion credit for the specified bus, zone or aggregate would be paid to the LSE along with auction clearing price for the 50 percent of NFTR that was sold to the third party.

Under the MMU proposal, the LSE would be able to set reservation prices in the auction for the sale of portions or all of its NFTR. Third parties would have an opportunity to bid for the offered portions of the NFTR, and the market for the congestion revenue associated with the specified bus, zone or aggregate would clear at a price. If the reservation price of an identified portion of the offered NFTR was not met at the clearing price, that portion of the offered NFTR would remain with the load. Auctions could be offered annually and monthly. Portions of an NFTR associated with a specific bus, node or aggregate could be traded bilaterally between parties.

Auction Revenue Rights

ARRs

Auction Revenue Rights (ARRs) are the mechanism used to define the rights to congestion and assign those rights to congestion revenues to load. ARRs are assigned to load using an archaic path based approach. Congestion rights represented by ARRs are sold to FTR buyers in FTR Auctions. ARR values

are based on nodal price differences established by cleared FTR bids in the Annual FTR Auction. ARR sellers have no opportunity to define a price at which they are willing to sell. ARR holders must accept the prices as defined by FTR buyers. ARR revenues are a function of FTR auction participants' expectations of congestion, risk, competition and available supply. PJM has significant discretion over the level of supply made available to FTR buyers. The appropriate goals of that discretion need to be significantly limited and defined clearly in the tariff.

ARRs are available only as obligations (not options) and only as a 24 hour product. ARRs are available to the nearest 0.1 MW. The ARR target allocation is equal to the product of the ARR MW and the price difference between the ARR sink and source from the Annual FTR Auction.[9] An ARR's target allocation, or value, which is established from the Annual FTR Auction, can be a benefit or liability depending on the price difference between sink and source. If the combined net revenues from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions are greater than the sum of all ARR target allocations, ARRs are fully funded, otherwise, available revenue is proportionally allocated among all ARR holders. If auction revenues are greater than ARR target allocations, the revenue is first used to fully fund ARRs in previous months, then fully fund FTRs, and then provided to ARR holders at the end of the planning period.

The goal of the ARR/FTR design should be to provide an efficient mechanism to ensure that load receives the rights to all congestion revenues, and that ARR holders receive the auction revenues associated with all potential congestion revenues whether through self scheduling or selling the rights to FTR holders. Given that ARR holders have rights to all congestion revenue and the FTR auction is the way in which ARR holders exchange rights to congestion for fixed payments, then 100 percent of the FTR auction revenue should be assigned to ARR holders. The MMU recommends that all FTR auction revenues be allocated to ARR holders.

When a new control zone is integrated into PJM, firm transmission customers in that control zone may choose to receive either an FTR allocation or an ARR allocation before the start of the Annual FTR Auction for two consecutive planning periods following their integration date. After the transition period, such participants receive ARRs from the annual allocation process and are not eligible for directly allocated FTRs. Network service users and firm transmission customers cannot choose to receive both an FTR allocation and an ARR allocation. This selection applies to the participant's entire portfolio of ARRs that sink into the new control zone. During this transitional period, the directly allocated FTRs are reallocated, as load shifts between LSEs within the transmission zone.

IARRs

Incremental Auction Revenue Rights (IARRs) are ARRs made available by physical transmission system upgrades from customer funded transmission projects or from merchant transmission or generation interconnection requests. In order for a transmission project to result in IARRs, the project must create simultaneously feasible incremental market flow capability in PJM's ARR market model, over and above all system capability being used by existing allocated ARRs and/or would be used by granting any prorated outstanding ARR requests, in the ARR market model.[10]

There are three approaches to the creation and assigning of IARRs: IARRs can be requested based on specific transmission investment; IARRs can be the granted based on merchant transmission or generation interconnection projects; and IARRs can be the result of RTEP upgrades. In each case, the participants paying for the upgrades are allocated the IARR that are created. There have been 13 successful IARR requests totaling 2,990.1 MW of IARRs. One IARR path of 64.5 MW was terminated early (June 1, 2012), leaving 12 unique source and sink combinations of 2,925.6 MW of IARRs active in PJM's current ARR/FTR market. Of the 12 unique paths, 6 paths consisting of 1,047.4 MW, were from merchant transmission requests, 3 paths consisting of

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

10 See PJM Incremental Auction Revenue Rights Model Development and Analysis, PJM June 12, 2017. <https://www.pjm.com/~/media/markets-ops/ftr/pjm-iarr-model-development-and-analysis.ashx>.

1,200.0 MW were from generation interconnection requests and three paths consisting of 678.6 MW were from customer funded transmission projects.

IARRs are allocated to customers that have been assigned cost responsibility for certain upgrades included in PJM's RTEP. These customers as defined in Schedule 12 of the Tariff are network service customers and/or merchant transmission facility owners that are assigned the cost responsibility for upgrades included in the PJM RTEP. PJM calculates IARRs for each regionally assigned facility and allocates the IARRs, if any are created by the upgrade, to eligible customers based on their share of cost responsibility. The customers may choose to decline the IARR allocation during the annual ARR allocation process.[11] Each network service customer within a zone is allocated a share of the IARRs in the zone based on their share of the network service peak load of the zone.

The MMU recommends that IARRs be eliminated from the PJM tariff. The MMU supports increased competition to provide transmission using market mechanisms. The IARR process is not a viable mechanism for facilitating competitive transmission investments. Continuing to pretend that the IARR process is viable may impede the search for real solutions. PJM's process for using IARRs is fundamentally flawed and cannot be made consistent with the requirements of Order No. 681 which established IARRs.[12]

Order No. 681 requires that long-term firm transmission rights made feasible by transmission upgrades or expansions must be available upon request to the party that pays for such upgrades or expansions.[13] Order No. 681 also requires that the rights granted by upgrades/expansions cannot come at the expense of transmission rights held by others. IARRs are treated as Stage 1A rights. Granting Stage 1A status to IARRs is preferential treatment of IARR rights relative to the ARR rights belonging to load. Only a subset of the ARR rights are treated as Stage 1A rights. Stage 1A rights are given first and absolute priority in PJM's annual allocation process. If the annual market model used to assign existing ARR rights in a given year cannot simultaneously support all Stage 1A ARR requests, the system model is modified so as to make the Stage 1A ARR requests feasible. The result is an over allocation of congestion rights relative to expected congestion. To avoid having FTR target allocations exceed expected congestion, PJM reduces the annual supply (market model system capability) available to non-Stage 1A rights through selective line outages and line rating reductions. The resulting market model artificially supports all the Stage 1A ARR requests and artificially reduces the amount of remaining later tier ARRs from other rights holders. Stage 1A ARRs, including IARRs, are artificially approved at the expense of other preexisting congestion rights. In the case of IARRs, this is in violation of Order No. 681.

If IARRs are not eliminated, the MMU recommends that IARRs be subject to the same proration rules that apply to all other ARR rights.

Market Structure

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

Supply and Demand

The concept of system capability is not relevant to assigning the rights to congestion revenues to load. The use, or misuse, of system capability in assigning ARRs is derived entirely from the contract path approach used by PJM. In that approach, system capability available to ARR holders is limited by the system capability made available in PJM's annual FTR transmission system market model. PJM's annual FTR transmission market model represents annual, expected system capability, modified by PJM to achieve PJM's goal of guaranteeing revenue equal to target allocations for FTRs, and subject

11 "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020); "IARRs for RTEP Upgrades Allocated for 2016/2017 Planning Period," <http://www.pjm.com/~/media/markets-ops/ftr/annual-arr-allocation/2018-2019/2018-2019-iarrs-for-rtep-upgrades-allocated.ashx>.

12 See November 7, 2019 Comments on TranSource, LLC v. PJM, 168 FERC ¶ 61,119 (2019) ("Opinion No. 566").

13 Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, 116 FERC ¶61,077 (2006) ("Order No. 681"), order on reh'g, Order No. 618-A, 117 FERC ¶ 61,201 (2006), order on reh'g, Order No. 681-A, 126 FERC ¶ 61,254 (2009).

to the requirement that all Stage1A ARR requests must be allocated. Stage 1A ARR right requests are guaranteed and system capability necessary to accommodate the rights must be included in PJM's annual FTR transmission system market model.

ARR Allocation

For the 2007/2008 planning period, the annual ARR allocation process was revised to include Long Term ARRs that would be in effect for 10 consecutive planning periods.[14] Stage 1A ARRs can give LSEs the ability to offset at least some of their congestion costs, through the return of congestion revenues, on a long-term basis up to Zonal Base Load. Stage 1B and Stage 2 ARRs must be simultaneously feasible in PJM's network model. Stage 1B and Stage 2 ARRs provide a method for ARR holders to have additional congestion revenues returned to them, up to Zonal Peak Load, in the planning period over their Stage 1A allocation, but may be prorated. ARR holders can self schedule ARRs as FTRs during the Annual FTR Auction.[15]

Each March, PJM allocates annual ARRs to eligible customers in a three stage process:

- **Stage 1A.** In the first stage of the allocation, network transmission service customers can obtain ARRs, up to their share of Zonal Base Load, which is the lowest daily peak load in the prior twelve month period increased by load growth projections. The amount of Stage 1A ARRs a participant can request is based on generation to load paths that reflect generation resources that had historically served load, or their qualified replacements if the resource has retired, in the historical reference year for the zone. The historical reference year is the year prior to the creation of PJM markets, which is 1999 for the original zones, or the year in which a zone joined PJM. Firm, point to point transmission service customers can obtain Stage 1A ARRs, up to 50 percent of the MW of firm, point to point transmission service provided between the receipt and delivery points for the historical reference year. Stage 1A ARRs cannot be prorated. If Stage 1A ARRs are found to be infeasible, transmission system upgrades must be undertaken to maintain feasibility.
- **Stage 1B.** Transmission capacity unallocated in Stage 1A is available in the Stage 1B allocation for the planning period. Network transmission service customers can obtain ARRs up to their share of zonal peak load, which is the highest daily peak load in the prior twelve month period increased by load growth projections, based on generation to load paths and up to the difference between their share of zonal peak load and Stage 1A allocations. Firm, point to point transmission service customers can obtain ARRs based on the MW of long-term, firm, point to point service provided between the receipt and delivery points for the historical reference year.
- **Stage 2.** Stage 2 of the annual ARR allocation allocates the remaining system capability equally in three steps. Network transmission service customers can obtain ARRs from any hub, control zone, generator bus or interface pricing point to any part of their aggregate load in the control zone or load aggregation zone up to their total peak network load in that zone. Firm, point to point transmission service customers can obtain ARRs consistent with their transmission service as in Stage 1A and Stage 1B.

Prior to the start of the Stage 2 annual ARR allocation process, ARR holders can relinquish any portion of their ARRs resulting from the Stage 1A or Stage 1B allocation process, provided that all remaining outstanding ARRs are simultaneously feasible following the return of such ARRs.[16] Participants may seek additional ARRs in the Stage 2 allocation.

Effective for the 2015/2016 planning period, when residual zonal pricing was introduced, an ARR will default to sinking at the load settlement point if different than the zone, but the ARR holder may elect to sink their ARR at the zone instead.[17]

14 See *2006 State of the Market Report* (March 8, 2007) for the rules of the annual ARR allocation process for the 2006 to 2007 and prior planning periods.
15 OATT Attachment K 7.1.1.(b).
16 *Id.* at 21.
17 *See* "Residual Zone Pricing," PJM Presentation to the Members Committee (February 23, 2012) <http://www.pjm.com/~/media/committees-groups/committees/mc/20120223/20120223-item-03-residual-zone-pricing-presentation.ashx>.

ARRs can be traded between LSEs prior to the first round of the Annual FTR Auction. Traded ARRs are effective for the full 12 month planning period.

When ARRs are allocated after Stage 1A, all ARRs must be simultaneously feasible, meaning that the modeled transmission system can support the approved set of ARRs. In making simultaneous feasibility determinations, PJM uses a power flow model of security constrained dispatch based on assumptions about generation and transmission outages.[18] If the requested set of ARRs is not simultaneously feasible, customers are allocated prorated shares in direct proportion to their requested MW and in inverse proportion to their impact on binding constraints, except Stage 1A ARRs:

Equation 13-1 Calculation of prorated ARRs[19]

$$MW = Constraint\ Capability\ x \left(\frac{Individual\ Requested\ MW}{Total\ Requested\ MW}\right) x \left(\frac{1}{MW\ impact\ on\ line}\right)$$

The effect of an ARR request on a binding constraint is measured using the ARR's power flow distribution factor. An ARR's distribution factor is the percent of each requested ARR MW that would have a power flow on the binding constraint. The PJM method prorates ARR requests in proportion to their MW value and impact on the binding constraint. The PJM method prorates only ARRs that cause the greatest flows on the binding constraint. Were all ARR requests prorated equally, regardless of their impact on the binding constraints, the result would reduce allocated ARRs below actually available ARRs.

FERC Order EL16-121: Stage 1A ARR Allocation

FERC ordered PJM to remove retired resources from the generation to load paths used to allocate Stage 1A ARRs.[20] PJM replaced retired units with operating generators, termed qualified replacement resources (QRRs).[21]

The method PJM implemented continues to rely on a contract path based approach. Existing Stage 1A resources are given their current allocations, while ARR allocations to QRRs that replace retired Stage 1A resources are prorated based on the feasibility of these ARRs after existing resources are allocated. As a result of this proration, ARRs for QRRs have lower priority than ARRs from generators that existed in 1998.

Generation to load paths, even from active generators, are based on a contract path model rather than a network model. Generation to load paths should not be used as a basis for assigning the rights to congestion revenue. Contract paths are not an accurate representation of the reasons that congestion is created or that load is served in a network and will, by definition, not accurately measure the exposure of load to congestion, especially by location.

Market Performance

Stage 1A Infeasibility

Stage 1A ARRs are allocated for a 10 year period, with the ability for a participant to opt out of any planning period. PJM conducts a simultaneous feasibility analysis to determine the transmission upgrades required to ensure that the long term ARRs can remain feasible. The rules provide that if a simultaneous feasibility test violation occurs in any year, PJM will identify or accelerate any transmission upgrades to resolve the violation and these upgrades will be recommended for inclusion in the PJM RTEP process.[22] But such transmission upgrades must pass PJM's RTEP process.

PJM's transmission planning process (RTEP) does not identify a need for new transmission associated with Stage 1A overallocations because there is, in fact, no need for new transmission associated with Stage 1A ARRs. The Stage 1A overallocation issue is a fiction based on the use of outdated and irrelevant generation to load paths to assign Stage 1A rights that have nothing to do with actual power flows. This continues to be true even with the replacement of retired generating units.

18 "PJM Manual 6: Financial Transmission Rights," Rev. 245 (April 1July 23,5, 2020).
19 See the *MMU Technical Reference for PJM Markets*, at "Financial Transmission Rights and Auction Revenue Rights," for an illustration explaining this calculation in greater detail. <http://www.monitoringanalytics.com/reports/Technical_References/references.shtml>.
20 156 FERC ¶ 61,180 (2016).
21 See FERC Docket No. EL16-6-003.
22 See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020) at 23.

For the 2018/2019 planning period, Stage 1A of the Annual ARR Allocation was infeasible, resulting in an over allocation of ARRs on the affected facilities. As a result, modeled system capability, in excess of actual system capability, was provided to the Stage 1A ARRs and added to the FTR auction. According to Section 7.4.2 (i) of the OATT, the capability limits of the binding constraints rendering these ARRs infeasible must be increased in the model and these increased limits must be used in subsequent ARR and FTR allocations and auctions for the entire planning period, except in the case of extraordinary circumstances.

Revenue

ARRs are allocated to qualifying customers rather than sold, so ARR revenue (target allocation) is different from the revenue that results from the FTR auctions which generally exceeds the sum of the ARR target allocations.

ARR Reassignment for Retail Load Switching

PJM rules provide that when load switches between LSEs during the planning period, a proportional share of associated ARRs that sink in a given control or load aggregation zone is automatically reassigned to follow that load.[23] ARR reassignment occurs daily only if the LSE losing load has ARRs with a net positive economic value. An LSE gaining load in the same control zone is allocated a proportional share of positively valued ARRs within the control zone based on the shifted load. ARRs are reassigned to the nearest 0.001 MW and may be reassigned multiple times over a planning period. Residual ARRs are also subject to reassignment. This practice supports competition by ensuring that the offset to congestion follows load, thereby removing a barrier to competition among LSEs and, by ensuring that only ARRs with a positive value are reassigned, preventing an LSE from assigning poor ARR choices to other LSEs. However, when ARRs are self scheduled as FTRs, the self scheduled FTRs do not follow load that shifts while the ARRs do follow load that shifts, and this may result in lower value of the ARRs for the receiving LSE compared to the total value held by the original ARR holder.

There were 31,683 MW of ARRs associated with $657,300 of revenue that were reassigned for the 2019/2020 planning period. There were 13,606 MW of ARRs associated with $78,900 of revenue that were reassigned in the first four months of the 2020/2021 planning period.

Table 13-3 summarizes ARR MW and associated revenue reassigned for network load in each control zone where changes occurred between June 2019 and September 2020.

Table 13-3 ARRs and ARR revenue automatically reassigned for network load changes by control zone: June 2019 through September 2020

	ARRs Reassigned (MW-day)		ARR Revenue Reassigned [Dollars (Thousands) per MW-day]	
Control Zone	2019/2020 (12 months)	2020/2021 (4 months)	2019/2020 (12 months)	2020/2021 (4 months)
AECO	373	200	$4.8	$1.0
AEP	5,435	1,627	$151.0	$5.8
APS	1,383	699	$39.4	$5.3
ATSI	2,865	1,407	$42.6	$6.9
BGE	2,252	907	$103.9	$15.3
ComEd	2,583	1,155	$27.1	$6.2
DAY	765	278	$9.3	$1.1
DEOK	839	335	$58.3	$6.6
DLCO	1,622	895	$5.8	$1.0
Dominion	632	370	$6.2	$3.6
DPL	702	270	$52.2	$3.8
EKPC	0	0	$0.0	$0.0
JCPL	1,032	414	$4.8	$1.2
Met-Ed	540	166	$5.6	$0.6
OVEC	0	0	$0.0	$0.0
PECO	3,196	1,831	$24.8	$3.0
PENELEC	570	176	$15.7	$1.3
Pepco	1,947	548	$35.4	$3.3
PPL	3,538	1,542	$38.3	$8.5
PSEG	1,340	707	$31.8	$4.3
RECO	69	80	$0.2	$0.0
Total	31,683	13,606	$657.3	$78.9

23 See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

Residual ARRs

Introduced August 1, 2012, Residual ARRs are available for eligible ARR holders when a transmission outage was modeled in the Annual ARR Allocation, but the transmission facility returns to service during the planning period. If ARR allocations are reduced as the result of a modeled transmission outage and the transmission outage ends during the relevant planning period, the result is that residual ARRs may be available. These residual ARRs are automatically assigned to eligible participants the month before the effective date. Residual ARRs are effective for single months, and cannot be self scheduled. Residual ARR target allocations are based on the clearing prices from FTR obligations in the relevant monthly auction, may not exceed zonal network services peak load or firm transmission reservation levels and are only available up to the prorated ARR MW capacity as allocated in the Annual ARR Allocation. For the following planning period, these Residual ARRs are available as ARRs in the annual ARR allocation. Residual ARRs are a separate product from incremental ARRs. Beginning with the June 2017 monthly auction, Residual ARRs that would have cleared with a negative target allocation are not assigned to participants.[24]

Table 13-4 shows the Residual ARRs (cleared volume) allocated to participants, along with the target allocations (bid and requested) from the effective month. In the first four months of the 2020/2021 planning period, PJM allocated a total of 16,997.8 MW of Residual ARRs with a target allocation of $3.6 million. In the same time period for the 2019/2020 planning period, PJM allocated a total of 11,162.7 MW of residual ARRs with a target allocation of $2.7 million. In the 2017/2018 planning period, PJM allocated a total of 39,597.4 MW of residual ARRs, up from 35,034.9 MW for the 2016/2017 planning period. Residual ARRs had a total target allocation of $17.5 million for the 2017/2018 planning period, up from $7.0 million for the 2016/2017 planning period. In prior planning periods, PJM's modeling of excess outages resulted in the allocation of some ARRs that could have been allocated in Stage 1B being allocated as Residual ARRs on a month to month basis without the option to self schedule.

24 See FERC Letter Order, Docket No. ER17-1057 (April 5, 2017).

Table 13-4 Residual ARR allocation volume and target allocation: January through September, 2020

Month	Available Volume (MW)	Cleared Volume (MW)	Cleared Volume	Target Allocation
Jan-20	4,635.1	2,534.1	54.7%	$3,469,317
Feb-20	5,972.9	2,506.8	42.0%	$799,038
Mar-20	4,905.7	2,659.5	54.2%	$1,269,201
Apr-20	4,529.7	2,619.0	57.8%	$787,262
May-20	5,717.4	2,523.5	44.1%	$471,472
Jun-20	3,889.8	1,945.8	50.0%	$397,786
Jul-20	3,845.1	2,027.7	52.7%	$973,082
Aug-20	3,493.2	2,029.0	58.1%	$1,256,615
Sep-20	5,769.7	2,040.8	35.4%	$968,024
Total	42,758.6	20,886.2	48.8%	$10,391,797

Financial Transmission Rights

FTRs are financial instruments that entitle their holders to receive revenue or require them to pay charges based on locational congestion price differences in the day-ahead energy market across specific FTR transmission paths. The value of the day-ahead congestion price differences, termed the FTR target allocation, defines the maximum, but not guaranteed, payout for FTRs. The target allocation of an FTR reflects the difference in day-ahead congestion prices (CLMPs) rather than the difference in LMPs, which includes both congestion and marginal losses. The difference in day-ahead congestion prices is not congestion. Negative target allocations require the FTR holder to pay into the FTR market. After FERC's order assigning balancing congestion and M2M payments directly to load, available revenue to pay FTR holders' target allocations in a given month is based on the amount of day-ahead congestion, payments by holders of negatively valued FTRs, additional auction revenues available at the end of a month over ARR target allocations, any charges made to day-ahead operating reserves and any surplus revenue from preceding months in these categories. The target allocations are a cap on payments to FTR holders. At the end of the planning period, any surplus revenue above the target allocations is distributed proportionally to ARR holders.

FTR funding is not on a path specific basis or on an hour to hour basis and treats all FTRs the same. The result is widespread cross subsidies because

assignment of path specific ARRs/FTRs may exceed system capability and affect the payments to FTRs on other paths. FTR auction revenues and excess revenues are carried forward from prior months and distributed back from later months within a planning period. At the end of a planning period, if some months remain not fully funded, an uplift charge is collected from any FTR market participants that hold FTRs for the planning period based on their pro rata share of total net positive FTR target allocations, excluding any charge to FTR holders with a net negative FTR position for the planning period.

Auction market participants are free to request FTRs between any eligible pricing nodes on the system, as released by PJM for each auction. For the Long Term FTR Auction there is a more restricted set of available hubs, control zones, aggregates, generator buses and interface pricing points available. For the Annual FTR Auction and FTRs bought for a quarterly period in the monthly auction, the available FTR source and sink points include hubs, control zones, aggregates, generator buses, load buses and interface pricing points. An FTR bought in the Monthly FTR Auction for any single calendar month following that auction may include any bus for which an LMP is calculated in the FTR model used. PJM does not allow FTR buy bids to clear with a price of zero unless there is at least one constraint in the auction which affects the FTR path. FTRs are available to the nearest 0.1 MW. The FTR target allocation is calculated hourly and is equal to the product of the FTR MW and the congestion price difference between sink and source that occurs in the day-ahead energy market.

Market Structure

FTRs are bought from supply defined by PJM. There are no sellers of congestion revenue rights, although FTR buyers can resell FTRs. Load cannot determine the price at which PJM sells FTRs. PJM's objective in the auctions is to maximize auction revenue, given the bid prices but absent reservation prices from load. The absence of sellers who can decide at what price to sell FTRs is a fundamental flaw in the FTR market. The result is that PJM cannot actually maximize auction revenue.

Once bought from PJM, FTRs can be bought, sold and self scheduled. Buy bids are bids to buy FTRs in the auctions; sell offers are offers to sell existing FTRs in the auctions; and self scheduled bids are FTRs that have been directly converted from ARRs in the Annual FTR Auction. Self scheduled FTRs represent the choice by an ARR holder to be paid based on actual day-ahead congestion revenue rather than the fixed ARR value determined in the annual FTR auction.

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

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

PJM operates three types of auctions for FTRs. The objective function of all FTR auctions is to maximize the bid based value of FTRs awarded in each auction. PJM conducts an Annual FTR Auction, Monthly Balance of Planning Period FTR Auctions for the remaining months of the planning period and a Long Term FTR Auction for the following three consecutive planning periods.[25] FTR options are not available in the Long Term FTR Auction.

A self scheduled FTR must have the same source and sink points as the ARR and be a 24 hour obligation product and can only be purchased in the Annual FTR Auction. Self scheduled FTRs exchange an ARR for a matching FTR without making a payment. From a settlements perspective, the self

25 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

scheduling participant is paid the ARR target allocation, which is used to pay the price of the FTR. The participant then receives the hourly congestion LMP difference of their source and sink points as any other FTR would.

A secondary bilateral market is also administered by PJM to allow participants to buy and sell existing FTRs. FTRs can also be exchanged bilaterally outside PJM markets. There is no requirement to provide PJM any information on bilateral transactions, including price, counterparties, or ultimate separation by path.

Supply and Demand

Total FTR supply in each auction is limited by the capability of the transmission system included in the PJM FTR market model as modified, for example, by PJM assumptions about outages, for which there are no clear rules. PJM may also limit available capability through subjective judgment exercised without any clear guidelines. PJM outage assumptions are a key factor in determining the supply of ARRs and the related supply of FTRs in the Annual FTR Auction. Long Term FTR Auction capability is determined by removing all outages and running an offline model of the previous Annual FTR Auction model with all ARR bids. Any ARR MW that clear are reserved for ARR holders in their effective planning periods, and are removed from the Long Term FTR Auction capability. This does not, and cannot, preserve all possible capacity for ARR holders before a long term auction due to changes in system topology and outage selection between planning periods. Total Monthly FTR Auction capacity is based on the residual capacity available after the Long Term and Annual FTR auctions are conducted and adjustments are made to outages to reflect anticipated system conditions for the time periods auctioned.

The MMU recommends that the full transmission capacity of the system be allocated as ARRs prior to sale as FTRs.

Depending on assumptions used in the auction transmission model, the total FTR supply can be greater than or less than system capability in aggregate and/or on a path basis. FTR supply greater than system capability contributes to FTR target allocations exceeding congestion revenue. FTR supply less than system capability contributes to congestion revenue in excess of target allocations.

PJM can also make further subjective adjustments to the auction model to manage FTR revenues. PJM can assume arbitrarily higher outage levels and PJM can decide to include additional constraints (closed loop interfaces) both of which reduce system capability in the auction model. These PJM actions reduce the supply of available Stage 1B and Stage 2 ARRs, which in turn reduce the number of FTRs available for purchase. PJM made very significant adjustments starting in the 2014/2015 planning period auction model through the 2016/2017 planning period resulting in a drop of Stage 1B and Stage 2 ARR capacity of 86.1 percent from the 2013/2014 to the 2014/2015 planning periods. After balancing congestion was assigned to load and exports, beginning in the 2017/2018 planning period, PJM partially reversed their approach and ARR capacity increased to 2013/2014 planning period levels.

The auction process does not account for the fact that significant transmission outages, which have not been provided to PJM by transmission owners prior to the auction date, will occur during the periods covered by the auctions. Such transmission outages may or may not be planned in advance or may be emergency outages.[26] In addition, it is difficult to model in an annual auction two outages of similar significance and similar duration in different areas which do not overlap in time. The choice of which to model may have significant distributional consequences. The fact that outages are modeled at significantly lower than historical levels results in selling too many FTRs which creates downward pressure on revenues paid to each FTR. To address this issue, the MMU recommends that PJM use probabilistic outage modeling to better align the supply of ARRs and FTRs with actual system capabilities.

Long Term FTR Auctions

In July 2006, FERC issued a Final Rule mandating the creation of long term firm transmission rights in transmission organizations with organized electricity markets (FERC Docket No. RM06-8-000; Order No. 681).[27] FERC's goal was

26 See the *2019 State of the Market Report for PJM*, Volume 2, Section 12: Transmission Facility Outages: Transmission Facility Outages Analysis for the FTR Market.
27 116 FERC ¶ 61,077 (2006).

that "load serving entities be able to request and obtain transmission rights up to a reasonable amount on a long-term firm basis, instead of being limited to obtaining exclusively annual rights." Despite that order and inconsistent with the directive in that order, LSEs are not able to request ARRs nor are LSEs guaranteed rights to the revenue from Long Term FTR Auctions in PJM's long term FTR auction market design. Excess system capability in years two and three of the long term FTR auction are never made available to load in the form of ARRs and are only made available to FTR buyers.

PJM conducts a Long Term FTR Auction for the next three consecutive planning periods. The capacity offered for sale in Long Term FTR Auctions is the residual system capability assuming that all allocated ARRs are self scheduled as FTRs. PJM expands the available transmission capacity for the Long Term FTR Auction by removing all the transmission outages included in the model when allocating ARRs.

Beginning with Round 2 of the 2019/2022 Long Term FTR Auction, PJM implemented revisions to the determination of residual system capability made available in the Long Term FTR Auctions, and eliminated the YRALL product, consistent with the MMU's recommendation. The revisions affect the determination of ARR rights reserved for ARR holders. Rather than simply preserving the ARR cleared capacity from the previous annual allocation, PJM reruns the simultaneous feasibility test for the ARR/FTR market model, without outages, using the previous year's ARR requests, prorated when necessary, and use the resulting ARRs as the basis for reserving capability for ARR holders in the Long Term FTR Auction. The ARR requests are greater than previously cleared ARRs. The difference between the requested ARRs and ARR/FTR market model's system capability, without outages, determines the residual capability offered in the Long Term FTR Auction. This method provides ARR holders with an improved representation of future system capability and preserves more congestion rights in the Long Term FTR Auction for ARR holders that will carry into the Annual FTR Auction than was preserved for ARR holders before this change. But this change does not address the system capability sold in years two and three of the Long Term FTR Auction which remains unavailable to ARRs. Capacity awarded in the Long Term FTR Auction is modeled as a fixed injection/withdrawal in the Annual FTR Auction, and is therefore unavailable in upcoming auctions. While the new rules will improve the allocation of congestion rights to ARR holders, a proportion of congestion revenues will still be assigned to the Long Term FTR Auction without ever having been made available to ARR holders. Due to the duration of long term FTRs and the variable nature of the ARR/FTR model's outage selections and system topology, reserving the previous year's ARR bids does not capture all of the capability that should be available to ARR holders. Any capability that is auctioned in the Long Term FTR Auction, and that should otherwise be available to ARR holders, results in lost revenue to ARR holders. That outcome is inconsistent with the basic logic of ARRs and inconsistent with the stated intent of the market design which is to return all congestion revenues to load.

The 2009/2012 and 2010/2013 Long Term FTR Auctions consisted of two rounds.[28] Subsequent Long Term FTR Auctions consist of three rounds. FTRs purchased in prior rounds may be offered for sale in subsequent rounds. FTRs obtained in the Long Term Auctions may have terms of any one of the next three. FTR products available in the Long Term Auction include 24 hour, on peak and off peak FTR obligations. FTR option products are not available in Long Term FTR Auctions.

- Round 1. The first round is conducted in the June prior to the start of the term covered by the Long Term FTR Auction and uses PJM's Summer Model build. Market participants make offers for FTRs between any source and sink.
- Round 2. The second round is conducted in September, uses the Summer Model build and follows the same rules as Round 1.
- Round 3. The third round is conducted in December, uses the Fall Model build and follows the same rules as Round 1.

28 FERC approved, on December 7, 2009, the addition of a third round to the Long Term FTR Auction. FERC letter order accepting PJM Interconnection, L.L.C.'s revisions to Long-Term Financial Transmission Rights Auctions to its Amended and Restated Operating Agreement and Open Access Transmission Tariff, Docket No. ER10-82-000 (December 7, 2009).

Annual FTR Auctions

Annual FTRs are effective beginning June 1 of the planning period through May 31. Outages expected to last two or more months, as well as any outages of a shorter duration that PJM determines would cause FTR revenue inadequacy if not modeled, are included in the determination of the simultaneous feasibility for the Annual FTR Auction.[29] While the full list of outages selected is publicly posted, PJM exercises significant subjective judgment in selecting outages to accomplish FTR revenue adequacy goals and the process by which these outages are selected is not clear and is not documented. ARR holders who wish to self schedule must inform PJM prior to round one of the annual auction. Any self scheduled ARR requests clear 25 percent of the requested volume in each round of the Annual FTR Auction as price takers. This auction consists of four rounds that allow any transmission service customers or PJM members to bid for any FTR or to offer for sale any FTR that they currently hold. FTRs in this auction can be obligations or options for peak, off peak or 24 hour periods. FTRs purchased in one round of the Annual FTR Auction can be sold in later rounds or in the Monthly Balance of Planning Period FTR Auctions.

The FTRs sold in the Long Term FTR Auction for a future delivery year may conflict with the ARRs assigned to load in the ARR allocation process when that delivery year is effective. By not properly reserving all ARR capacity in the Long Term FTR Auction, it is possible that a SFT violation may occur between a long term FTR and a self scheduled ARR, resulting in revenue adequacy issues.

Monthly Balance of Planning Period FTR Auctions

The residual capability of the PJM transmission system, after the Long Term and Annual FTR Auctions are concluded, is offered in the Monthly Balance of Planning Period FTR Auctions. Outages expected to last five or more days are included in the determination of the simultaneous feasibility test for the Monthly Balance of Planning Period FTR Auction. These are single-round monthly auctions that allow any transmission service customer or PJM member to bid for any FTR or to offer for sale any FTR that they currently hold. Before the 2020/2021 planning period, the first three individual months, and quarterly periods that had not yet begun, were available for bid or offer. Beginning with the 2020/2021 planning period, market participants can bid for or offer monthly FTRs for any of the remaining individual calendar months in the planning period. FTRs in the auctions include obligations and options and 24 hour, on peak and off peak products.[30]

Secondary Bilateral Market

Market participants can buy and sell existing FTRs through the PJM bilateral market which is actually a voluntary posting bulletin board and not a PJM administered market, or market participants can trade FTRs among themselves without PJM involvement. There is currently no requirement to report bilateral transactions, or any information about them, to PJM. Bilateral transactions that are not done through PJM can involve parties that are not PJM members. PJM has no knowledge of bilateral transactions, or the terms and risks of bilateral transactions, that are done outside of PJM's bilateral market system. Bilateral transactions not reported to PJM are dependent on the contract established between the parties.

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

FTR Bid Limits

PJM has had a cap of 10,000 bids and offers per auction round and per period at the corporate family level for more than a year, although the rule has not been enforced.[31] On December 11, 2019, PJM made an informational announcement to urge participants to respect the rule. Some participants have exceeded and continued to exceed the limit although the number has been

29 See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

30 "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

31 Operating Agreement Schedule 1 § 7.3.5(d) allows PJM to limit participant's bids to 5,000 to avoid or mitigate significant system performance problems related to bid/offer volume.

significantly reduced very recently. The MMU recommends that PJM enforce the FTR auction bid limits at the corporate family level starting immediately.

Patterns of Ownership

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

Table 13-5 presents the monthly balance of planning period FTR auction cleared FTRs for the first nine months of 2020 by trade type, organization type and FTR direction. Financial entities purchased 84.5 percent of prevailing flow FTRs, up 12.8 percentage points, and 87.1 percent of counter flow FTRs, up 7.2 percentage points, from 2019, with the result that financial entities purchased 85.8 percent, up 10.5 percentage points, of all prevailing and counter flow FTR buy bids in the monthly balance of planning period FTR auction cleared FTRs for 2020.

Table 13-5 Monthly Balance of Planning Period FTR Auction patterns of ownership by FTR direction: January through September, 2020

		FTR Direction		
Trade Type	Organization Type	Prevailing Flow	Counter Flow	All
Buy Bids	Physical	15.5%	12.9%	14.2%
	Financial	84.5%	87.1%	85.8%
	Total	100.0%	100.0%	100.0%
Sell Offers	Physical	8.1%	10.9%	9.0%
	Financial	91.9%	89.1%	91.0%
	Total	100.0%	100.0%	100.0%

Table 13-6 shows the HHI values for cleared MW for the first four months of the 2020/2021 planning period monthly auctions by period. Cleared buy bids are unconcentrated.[32]

Table 13-6 Monthly Balance of Planning Period FTR Auction HHIs by period

	Auction Period											
Auction	JUN	JUL	AUG	SEP	OCT	NOV	DEC	JAN	FEB	MAR	APR	MAY
Jun-20	283	361	425	427	585	566	644	544	576	625	650	596
Jul-20		293	306	373	460	441	521	473	471	500	535	528
Aug-20			326	340	373	382	432	409	417	439	452	443
Sep-20				363	374	388	462	499	509	505	551	532

Table 13-7 shows the average daily held FTR ownership for all FTRs for the first nine months of 2020, by FTR direction.

Table 13-7 Daily FTR held position ownership by FTR direction: January through September, 2020

	FTR Direction		
Organization Type	Prevailing Flow	Counter Flow	All
Physical	32.5%	16.7%	25.6%
Financial	67.5%	83.3%	74.4%
Total	100.0%	100.0%	100.0%

Market Performance

Volume

PJM regularly intervenes in the FTR market based on subjective judgment which is not based on clear or documented guidelines. Such intervention in the FTR, or any market, is not appropriate and not consistent with the operation of competitive markets. In an apparent effort to manage FTR revenues, PJM may adjust normal transmission limits in the FTR auction model. If, in PJM's judgment, the normal capability limit is not consistent with revenue adequacy goals and simultaneous feasibility, then FTR Auction capability reductions are undertaken pro rata based on the MW of Stage 1A infeasibility and the availability of auction bids for counter flow FTRs.[33] PJM may also remove or reduce infeasibilities caused by transmission outages by clearing counter

32 *See 2020 Quarterly State of the Market Report for PJM: January through June* Section 3: Energy Market, Competitive Assessment for HHI definitions.

33 See "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

flow bids without being required to clear the corresponding prevailing flow bids.[34] The use of both of these procedures is contingent on PJM actions not affecting the revenue adequacy of allocated ARRs, all requested self scheduled FTRs clear and net FTR auction revenue is positive.

Monthly Balance of Planning Period Auctions

Table 13-8 provides the monthly balance of planning period FTR auction market volume for the entire 2019/2020 and the first four months of the 2020/2021 planning periods. There were 14,666,168 MW of FTR obligation buy bids and 6,262,241 MW of FTR obligation sell offers for all bidding periods in the first four months of the 2020/2021 planning period. The monthly balance of planning period FTR auction cleared 2,535,158 (17.3 percent) of FTR obligation buy bids and 1,093,325 MW (17.5 percent) of FTR obligation sell offers.

There were 2,839,031 MW of FTR option buy bids and 1,771,441 MW of FTR option sell offers for all bidding periods in the Monthly Balance of Planning Period FTR Auctions for the first four months of the 2020/2021 planning period. The monthly auctions cleared 185,504 MW (6.5 percent) of FTR option buy bids, and 264,627 MW (14.9 percent) of FTR option sell offers.

34 See *id.*

Table 13-8 Monthly Balance of Planning Period FTR Auction market volume: January through September, 2020

Monthly Auction	Type	Trade Type	Bid and Requested Count	Bid and Requested Volume (MW)	Cleared Volume (MW)	Cleared Volume	Uncleared Volume (MW)	Uncleared Volume
Jan-20	Obligations	Buy bids	466,394	1,632,289	306,659	18.8%	1,325,630	81.2%
		Sell offers	303,736	618,111	125,762	20.3%	492,349	79.7%
	Options	Buy bids	6,647	195,528	5,493	2.8%	190,035	97.2%
		Sell offers	12,782	109,543	21,508	19.6%	88,034	80.4%
Feb-20	Obligations	Buy bids	474,510	1,592,984	309,317	19.4%	1,283,667	80.6%
		Sell offers	185,838	470,656	102,698	21.8%	367,958	78.2%
	Options	Buy bids	5,425	162,253	8,471	5.2%	153,782	94.8%
		Sell offers	11,296	112,091	28,274	25.2%	83,817	74.8%
Mar-20	Obligations	Buy bids	494,921	1,719,197	362,450	21.1%	1,356,747	78.9%
		Sell offers	242,038	598,102	126,227	21.1%	471,875	78.9%
	Options	Buy bids	4,460	105,294	8,701	8.3%	96,594	91.7%
		Sell offers	12,688	143,455	33,009	23.0%	110,445	77.0%
Apr-20	Obligations	Buy bids	351,392	1,119,598	255,378	22.8%	864,220	77.2%
		Sell offers	135,345	391,710	83,809	21.4%	307,901	78.6%
	Options	Buy bids	2,168	79,078	4,892	6.2%	74,186	93.8%
		Sell offers	7,951	96,040	24,500	25.5%	71,540	74.5%
May-20	Obligations	Buy bids	257,961	776,159	172,022	22.2%	604,137	77.8%
		Sell offers	76,694	201,438	45,392	22.5%	156,046	77.5%
	Options	Buy bids	217	4,076	1,060	26.0%	3,017	74.0%
		Sell offers	4,091	50,564	14,164	28.0%	36,400	72.0%
Jun-20	Obligations	Buy bids	875,884	3,659,757	655,465	17.9%	3,004,293	82.1%
		Sell offers	564,024	1,712,557	306,600	17.9%	1,405,956	82.1%
	Options	Buy bids	10,981	477,584	25,913	5.4%	451,671	94.6%
		Sell offers	90,894	547,263	90,228	16.5%	457,035	83.5%
Jul-20	Obligations	Buy bids	915,321	3,905,518	656,876	16.8%	3,248,642	83.2%
		Sell offers	512,929	1,583,035	275,966	17.4%	1,307,070	82.6%
	Options	Buy bids	13,915	733,188	59,777	8.2%	673,411	91.8%
		Sell offers	85,233	433,833	62,005	14.3%	371,828	85.7%
Aug-20	Obligations	Buy bids	822,326	3,611,313	610,999	16.9%	3,000,314	83.1%
		Sell offers	522,235	1,577,873	284,252	18.0%	1,293,621	82.0%
	Options	Buy bids	14,022	822,980	56,719	6.9%	766,261	93.1%
		Sell offers	77,645	412,804	61,991	15.0%	350,813	85.0%
Sep-20	Obligations	Buy bids	724,927	3,489,579	611,818	17.5%	2,877,761	82.5%
		Sell offers	441,244	1,388,776	226,507	16.3%	1,162,268	83.7%
	Options	Buy bids	11,736	805,278	43,094	5.4%	762,184	94.6%
		Sell offers	60,552	377,541	50,403	13.4%	327,138	86.6%
2019/2020*	Obligations	Buy bids	5,926,122	20,396,353	3,975,985	19.5%	16,420,368	80.5%
		Sell offers	3,436,131	7,709,887	1,586,486	20.6%	6,123,402	79.4%
	Options	Buy bids	86,428	2,779,104	148,918	5.4%	2,630,186	94.6%
		Sell offers	179,301	1,656,059	409,029	24.7%	1,247,031	75.3%
2020/2021**	Obligations	Buy bids	3,338,458	14,666,168	2,535,158	17.3%	12,131,009	82.7%
		Sell offers	2,040,432	6,262,241	1,093,325	17.5%	5,168,915	82.5%
	Options	Buy bids	50,654	2,839,031	185,504	6.5%	2,653,527	93.5%
		Sell offers	314,324	1,771,441	264,627	14.9%	1,506,814	85.1%

* Shows 12 months for 2019/2020 ** Shows 4 months for 2020/2021

Figure 13-1 shows the bid volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The prompt month is the first month for which FTRs are sold. The bid volume for the non-prompt months is significantly lower than in the prompt months. On average, the non-prompt month bid volume is 38.2 percent of the prompt month bid volume.

Figure 13-1 Monthly Balance of Planning Period FTR Auction bid volume (MW per period): June through September, 2020 Auction

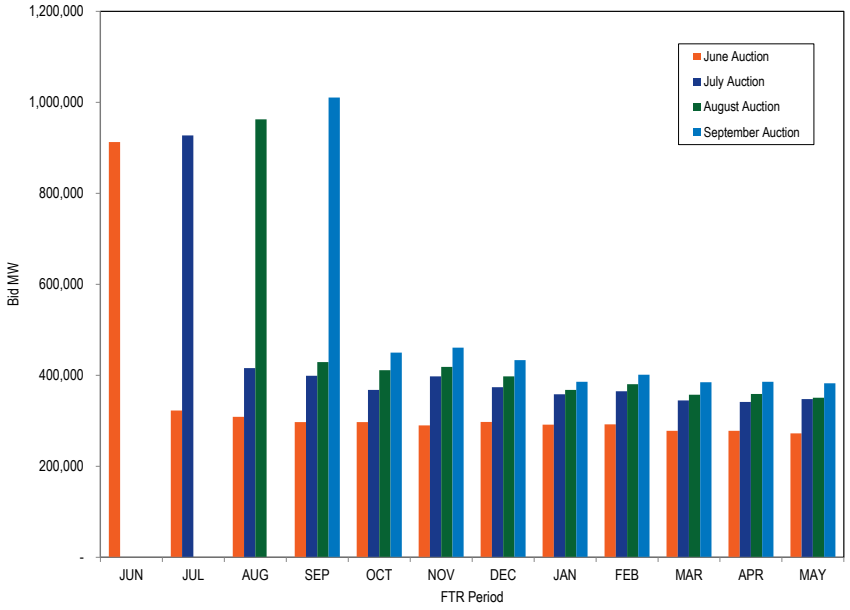
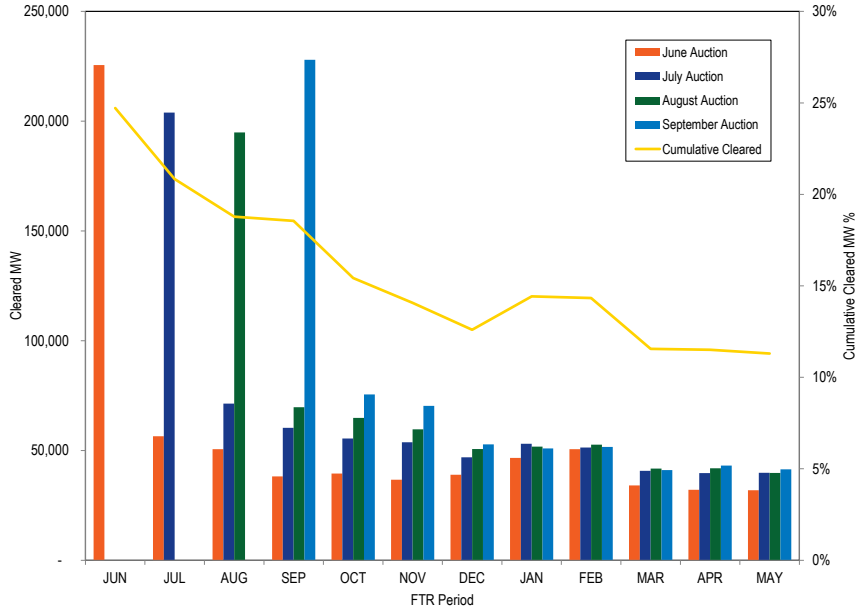


Figure 13-2 shows the cleared volume from each monthly auction for each period of the Monthly Balance of Planning Period FTR Auction. The cleared volume for non-prompt months is also significantly lower than in prompt months. On average, the non-prompt month cleared volume is 23.5 percent of the prompt month cleared volume.

Figure 13-2 Monthly Balance of Planning Period FTR Auction cleared volume (MW per period): June through September, 2020 Auction



Secondary Bilateral Market

Table 13-9 provides the PJM registered secondary bilateral FTR market volume for the 2019/2020 and the 2020/2021 planning periods. Bilateral FTR transactions registered through PJM do not need to include an accurate price or the entire volume of the transaction. Bilateral FTR transactions are not required to be registered through PJM. As a result, the bilateral data are not a reliable basis for evaluating actual bilateral activity in PJM FTRs.

Table 13-9 Secondary bilateral FTR market volume: 2019/2020 and 2020/2021[35]

Planning Period	Type	Class Type	Volume (MW)
2019/2020	Obligation	24-Hour	5,032.9
		On Peak	1,996.1
		Off Peak	1,661.8
		Total	8,690.8
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	0.0
		Total	0.0
2020/2021	Obligation	24-Hour	2,404.0
		On Peak	22.0
		Off Peak	21.0
		Total	2,447.0
	Option	24-Hour	0.0
		On Peak	0.0
		Off Peak	0.0
		Total	0.0

Figure 13-3 shows the FTR bid, net bid and cleared volume from June 2003 through September 2020 for Long Term, Annual and Monthly Balance of Planning Period Auctions. Cleared volume includes FTR buy and sell offers that were accepted. The net bid volume includes the total buy, sell and self scheduled offers, counting sell offers as a negative volume. The bid volume is the total of all bid and self scheduled offers, excluding sell offers. The cleared volume in August 2018 was negative due to the liquidation of the GreenHat FTR portfolio, which resulted in a large quantity of FTRs selling in the monthly auction.

Figure 13-3 Long Term, Annual and Monthly FTR Auction bid and cleared volume: June 2003 through September 2020

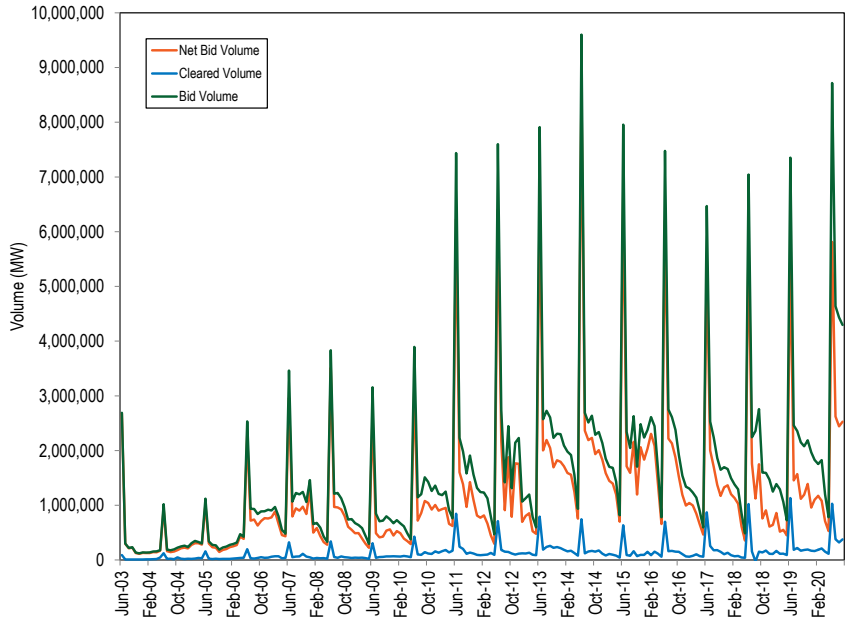


Figure 13-4 shows cleared auction volumes by auction type as a percent of the total FTR cleared volume by calendar months for June 2004 through September 2020. FTR volumes are included in the calendar month they are effective, with long term and annual FTR auction volumes spread equally to each month in the relevant planning period. Over the course of each planning period an increasing number of Monthly Balance of Planning Period FTRs are purchased, resulting in a greater share of total FTRs. When the Annual FTR Auction occurs, FTRs purchased in previous Monthly Balance of Planning Period Auctions, other than the current June auction, are no longer effective, resulting in a smaller share for monthly and a greater share for annual FTRs.

35 The 2019/2020 planning period covers bilateral FTRs that are effective for any time between June 1, 2019 through May 31, 2020, which originally had been purchased in a Long Term FTR Auction, Annual FTR Auction or Monthly Balance of Planning Period FTR Auction.

Figure 13-4 Cleared auction volume (MW) as a percent of total FTR cleared volume by calendar month: June 2004 through September 2020

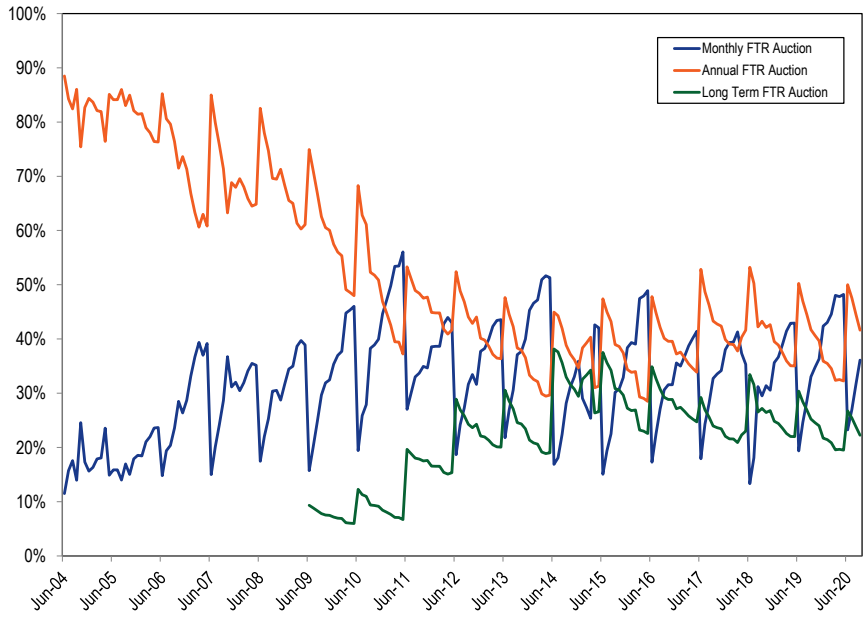
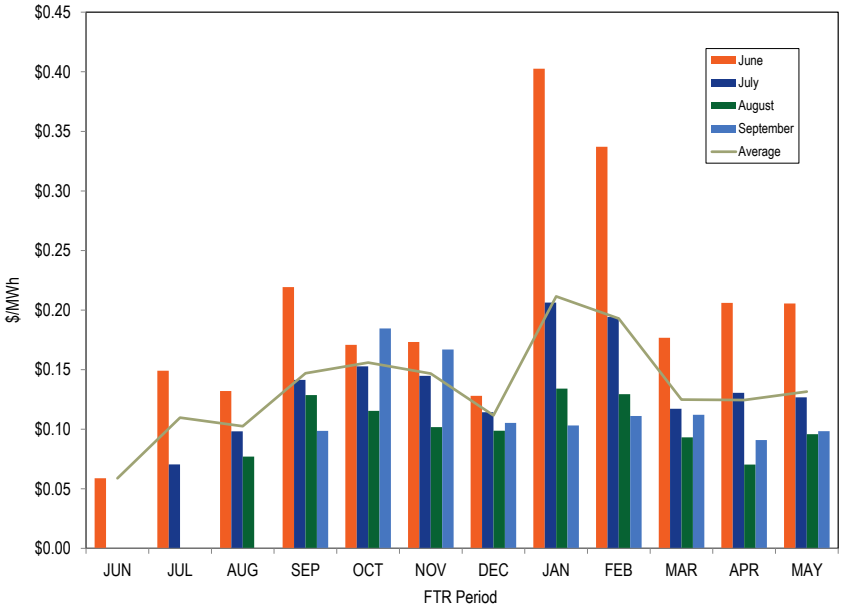


Figure 13-5 Monthly Balance of Planning Period FTR Auction cleared, weighted-average, buy bid price per period (Dollars per MWh): 2020/2021 planning period



Price

Figure 13-5 shows the weighted average cleared buy bid price of obligations in the Monthly Balance of Planning Period FTR Auctions by bidding period for the first four months of the 2020/2021 planning period and the average price per MWh for each of the FTR periods.

Profitability

FTR profitability is the difference between the revenue received directly from holding an FTR plus any revenue from the sale of an FTR, and the cost of the FTR. For a prevailing flow FTR, the FTR revenue is the actual revenue that an FTR holder is paid as the target allocation plus the auction price from the sale of the FTR, if relevant, and the FTR cost is the auction price. For a counter flow FTR, the FTR revenue is the auction price that an FTR holder is paid to take the FTR plus the positive auction price from the sale of the FTR, if relevant, and the FTR cost is the target allocation that the FTR holder must pay plus the negative auction price from the sale of the FTR, if relevant. Bilateral transactions are excluded from the profit calculations because there are inconsistent reporting requirements and no assurance that reported

prices reflect the actual prices. ARR holders that self schedule FTRs receive congestion revenues but do not receive profits from those FTRs because ARR holders are assigned rights to congestion revenues which they choose to take directly as the congestion payments associated with the corresponding FTRs.

Hourly FTR profits are the sum of the hourly revenues minus the hourly costs for each FTR (not self scheduled) held by an organization. The hourly revenues equal hourly FTR target allocations, adjusted by the payout ratio. The hourly auction costs are the product of the FTR MW and the auction price divided by the time period of the FTR in hours. The FTR revenues do not include after the fact adjustments which are very small and do not occur in every month.

The surplus includes surplus day-ahead congestion revenue and FTR auction surplus. At least part of the surplus is included in FTR profits because the surplus is first allocated to FTR holders to cover any shortfall in paying FTR target allocations. Beginning with the 2018/2019 planning period, after covering any shortfall in FTR target allocations within the planning period, the net surplus at the end of the planning period is distributed to ARR holders.

The fact that FTR profits in each planning period have been positive for financial entities as a group, regardless of the payout ratio, raises questions about the competitiveness of the market. FTR profits for financial entities were not positive in the 2019/2020 planning period when accounting for GreenHat losses but were positive otherwise. FTR profits for financial entities without GreenHat losses were positive in every completed planning period from 2012/2013 through 2020/2021 except the 2016/2017 planning period, and were positive if summed over the entire period (Table 13-12). It is not clear, in a competitive market, why FTR profits for financial entities remain persistently profitable. In a competitive market, it would be expected that profits would be competed to zero.

Table 13-10 lists FTR profits, and the congestion returned through self scheduled FTRs, by organization type and FTR direction for FTRs for the first four months of the 2020/2021 planning period. This table includes the auction cost and revenue from both buying and selling FTRs that were effective between June 2020 and September 2020. This includes FTRs from the 2018/2021, 2019/2022 and 2020/2023 Long Term auctions, the 2020/2021 Annual auction, and the Monthly auctions from June 2020 to September 2020. The costs and revenues of the yearly FTR products are prorated based on the time period of the FTRs. Any revenues or costs related to bilateral transactions are not included in profits. All participants who were assigned ARRs are classified as physical ARR. Some participants that are not eligible for ARRs are classified as physical because they are physical participants, for example companies that own only generation.

Self scheduled FTRs have zero cost. ARR holders who self scheduled FTRs received $65.0 million in congestion revenues. Revenues from self scheduled FTRs are a return of congestion to the load that paid the congestion and are not profits.

Table 13-10 FTR profits and revenues by organization type and FTR direction: 2020/2021

	Purchased FTRs Profit			Self Scheduled FTRs Revenue Returned		
Organization Type	Prevailing Flow	Counter Flow	Total	Prevailing Flow	Counter Flow	Total
Financial	$24,807,375	$73,597,541	$98,404,916			
Financial without GreenHat	$25,227,516	$73,310,330	$98,537,846			
Physical	($472,235)	$27,115,544	$26,643,309			
Physical ARR	($5,528,371)	$16,907,850	$11,379,479	$378,540	$64,663,515	$65,042,055
Total	$18,806,769	$117,620,935	$136,427,704	$378,540	$64,663,515	$65,042,055

Table 13-11 lists the monthly FTR profits for the 2019/2020 planning period and the first four months of the 2020/2021 planning period by organization type. FTR profits include revenue from FTR sales and do not include any revenue or cost from bilateral transactions. FTR revenues for self scheduled FTRs are not included. FTR profits for FTRs purchased in auctions by ARR holders are included. In the first four months of the 2020/2021 planning period, profits for all participants were $136.4 million, up from $3.5 million profits for the same time period in the 2019/2020 planning period. The largest month to month increase in profits was in August, $54.9 million. Among

organization types, financial organizations had the largest increase in profits in the first four months of the 2020/2021 planning period, $92.8 million. The increase in profits was primarily a result of higher target allocations.

Table 13-11 Monthly FTR profits by organization type: 2019/2020 and 2020/2021[36]

	Organization Type				
Month	Financial	Financial without GreenHat	Physical	Physical ARR	Total
Jun-19	($7,530,412)	($5,175,703)	($4,406,629)	($5,300,686)	($17,237,726)
Jul-19	$11,073,631	$13,727,088	$1,715,298	$2,195,625	$14,984,553
Aug-19	($11,192,103)	($7,445,637)	($4,515,760)	($2,965,124)	($18,672,988)
Sep-19	$13,219,100	$20,305,030	$6,308,310	$4,870,000	$24,397,410
Oct-19	$6,628,121	$12,845,824	$2,404,277	$3,916,338	$12,948,736
Nov-19	$6,579,914	$10,996,869	$2,167,865	$2,038,284	$10,786,063
Dec-19	$6,176,313	$11,021,397	($212,596)	($3,696,208)	$2,267,509
Jan-20	($5,308,687)	($132,954)	($10,539,357)	($10,405,137)	($26,253,180)
Feb-20	($14,980,199)	($11,873,252)	($11,213,649)	($10,337,622)	($36,531,470)
Mar-20	($14,165,737)	($12,669,353)	($8,006,489)	($10,777,549)	($32,949,775)
Apr-20	($14,526,206)	($11,926,918)	($11,145,117)	($11,779,700)	($37,451,023)
May-20	$2,886,620	$5,478,459	($5,416,808)	($7,372,412)	($9,902,600)
Summary for Planning Period 2019/2020					
Total	($21,139,644)	$25,150,852	($42,860,656)	($49,614,191)	($113,614,490)
Jun-20	$13,554,491	$14,170,298	$2,967,605	($105,462)	$16,416,634
Jul-20	$35,653,206	$35,594,893	$9,241,525	$3,750,023	$48,644,754
Aug-20	$26,092,413	$25,931,889	$6,939,322	$3,240,451	$36,272,185
Sep-20	$23,104,806	$22,840,765	$7,494,858	$4,494,466	$35,094,131
Summary for Planning Period 2020/2021					
Total	$98,404,916	$98,537,846	$26,643,309	$11,379,479	$136,427,704

Table 13-12 lists the historical profits by calendar year by organization type beginning in the 2012/2013 planning period for FTRs purchased. (Profits do not include congestion revenue to self scheduled FTRs.) Profits include revenue from the sale of FTRs and exclude bilateral transactions. Profits include any end of planning period surplus distribution or uplift payments. The end of planning period surplus or uplift was distributed to FTR holders prorata based on FTR positive target allocations through the 2017/2018 planning period. Beginning with the 2018/2019 planning period, any net end of planning period surplus, after paying out any shortfall in FTR target allocations within the planning period, was distributed to ARR holders. Surplus allocated to ARR holders in the 2018/2019 planning period was $112.3 million, in the 2019/2020 planning period, it was $140.7 million and in the first four months of the 2020/2021 it was $7.1 million.

36 The GreenHat Default Allocation Assessment by PJM was $46.3 million for the 2019/2020 planning period and $133,000 for the 2020/2021 planning period, excluding the FTR Waiver Settlement of $17.5 million. The calculated GreenHat losses do not exactly match the assessment. The loss calculation is based on GreenHat's actual portfolio instead of the assessment formula and does not consider bilateral transaction or GreenHat's collateral.

Table 13-12 FTR profits by organization type: 2012/2013 through 2020/2021[37]

		2012/2013	2013/2014	2014/2015	2015/2016	2016/2017	2017/2018	2018/2019	2019/2020	2020/2021
Financial	Profit	$201,825,234	$913,502,323	$250,551,943	$68,895,867	($12,525,947)	$239,981,474	$113,086,231	($21,139,644)	$98,404,916
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918			
	Total	$151,520,826	$768,421,802	$270,005,781	$73,816,945	($3,715,680)	$330,343,392	$113,086,231	($21,139,644)	$98,404,916
Financial without GreenHat	Profit	$201,825,234	$913,502,323	$250,551,785	$70,094,918	($11,821,248)	$240,111,850	$223,376,757	$25,150,852	$98,537,846
	Surplus	($50,304,408)	($145,080,521)	$19,453,837	$4,921,078	$8,810,267	$90,361,918			
	Total	$151,520,826	$768,421,802	$270,005,623	$75,015,995	($3,010,981)	$330,473,768	$223,376,757	$25,150,852	$98,537,846
Physical	Profit	$68,537,800	$297,456,284	$82,853,390	$10,007,327	($4,010,669)	$57,532,872	($5,945,233)	($42,860,656)	$26,643,309
	Surplus	($41,626,011)	($53,642,077)	$5,395,706	$1,865,146	$4,181,855	$34,296,618			
	Total	$26,911,789	$243,814,207	$88,249,096	$11,872,473	$171,186	$91,829,490	($5,945,233)	($42,860,656)	$26,643,309
Physical ARR	Profit	$26,572,818	$366,128,947	$112,609,140	$82,181,795	($2,468,152)	$66,458,939	($6,248,557)	($49,614,191)	$11,379,479
	Surplus	($25,873,836)	($81,279,067)	$18,515,990	$7,110,576	$12,040,688	$47,753,635			
	Surplus from Self scheduled FTRs	($45,978,766)	($81,765,964)	$15,530,158	$3,073,711	$6,469,297	$42,513,186			
	Total	$698,982	$284,849,881	$131,125,130	$89,292,371	$9,572,536	$114,212,574	($6,248,557)	($49,614,191)	$11,379,479
Total		$179,131,597	$1,297,085,890	$489,380,007	$174,981,788	$6,028,043	$536,385,456	$100,892,442	($113,614,490)	$136,427,704

* Bilateral transactions are included in surplus allocation calculation but are not included in profits calculation

* The first four months of the 2020/2021 planning period

Table 13-13 shows the profits and losses of the five most and the five least profitable participants by organization type. Total MWh is the sum of all MWh by organization type regardless of profitability. The Top 5 Profit is the sum of the profits of the five most profitable participants by organization type. The Top 5 Profit/MWh is the Top 5 Profit divided by the sum of the MWh of the top five participants by organization. The Top 5 Market Share of MWh is the sum of the MWh of the top five participants by organization type divided by Total MWh. The Top 5 Profit Share Among Profitable Participants is the Top 5 Profit divided by the sum of the profits of all profitable participants by organization type. The same logic applies for the statistics related to the Bottom 5 participants. The All row includes all participants including all organization types when calculating the share of the profits and losses of the top 5 and bottom 5 participants. When all participants across organization types are considered, four of the Top 5 participants are financial organizations and three of the Bottom 5 are financial organizations. Of all the organization types, the Top 5 physical ARR organizations' share of profits is the highest, 91.1 percent, as is their share of MWh, 81.2 percent. There is only a small number of physical ARR participants who directly purchase FTRs. The Bottom 5 financial participants' share of losses is 82.9 percent while and their share of MWh is 11.7 percent. The losses from financial organizations are concentrated in a small number of participants. The Loss/MWh of the Bottom 5 financial organizations was the lowest, by organization type.

Table 13-13 Top five and bottom five FTR profits by organization type: 2020/2021: June through September

Organization Type	Total MWh	Top 5 Profit	Top 5 Profit/MWh	Top 5 Market Share in MWh	Top 5 Profit Share Among Profitable Participants	Bottom 5 Loss	Bottom 5 Loss/MWh	Bottom 5 Market Share in MWh	Bottom 5 Loss Share Among Unprofitable Participants
Financial	1,124,178,222	$40,303,698	$0.20	17.9%	33.3%	($18,612,256)	($0.14)	11.7%	82.9%
Financial without GreenHat	1,115,882,896	$40,303,698	$0.20	18.0%	33.3%	($18,612,256)	($0.14)	11.7%	83.4%
Physical	149,999,258	$21,922,478	$0.47	30.8%	59.2%	($6,348,258)	($0.28)	15.3%	61.3%
Physical ARR	146,994,659	$18,915,747	$0.16	81.2%	91.1%	($6,934,030)	($1.83)	2.6%	73.9%
All	1,421,172,140	$42,405,150	$0.18	16.2%	23.7%	($23,857,159)	($0.19)	8.6%	56.5%

37 Bilateral profits and losses net to zero in market total profits and losses.

Table 13-14 shows the shares of profitable and unprofitable FTR MWh by organization type in the first four months of the 2020/2021 planning period. All organization types had more profitable MWh than unprofitable MWh.

Table 13-14 MWh share by profitability by organization type: 2020/2021: June through September

Organization Type	Unprofitable	Profitable
Financial	19.1%	80.9%
Financial without GreenHat	18.5%	81.5%
Physical	24.6%	75.4%
Physical ARR	9.5%	90.5%
Total	18.7%	81.3%

Revenue

Monthly Balance of Planning Period FTR Auction Revenue

Table 13-15 shows monthly balance of planning period FTR auction revenue by trade type, type and class type for 2020. The Monthly Balance of Planning Period FTR Auctions for the first four months of the 2020/2021 planning period netted $20.8 million in revenue, the difference between buyers paying $125.7 million and sellers receiving $105.0 million. For the entire 2019/2020 planning period, the Monthly Balance of Planning Period FTR Auctions netted $52.9 million in revenue with buyers paying $331.1 million and sellers receiving $278.2 million.

Table 13-15 Monthly Balance of Planning Period FTR Auction revenue: January through September, 2020

Monthly Auction	Type	Trade Type	Class Type 24-Hour	On Peak	Off Peak	All
Jan-20	Obligations	Buy bids	$2,722,807	$9,772,463	$5,897,569	$18,392,839
		Sell offers	$613,192	$6,329,072	$3,861,063	$10,803,327
	Options	Buy bids	$8,255	$506,682	$330,074	$845,010
		Sell offers	$57,206	$3,134,561	$1,844,982	$5,036,749
Feb-20	Obligations	Buy bids	$8,482,540	$7,009,196	$2,400,689	$17,892,426
		Sell offers	$554,350	$7,558,765	$3,516,954	$11,630,068
	Options	Buy bids	$0	$614,467	$273,334	$887,800
		Sell offers	$39,630	$3,015,705	$1,524,774	$4,580,110
Mar-20	Obligations	Buy bids	$5,723,624	$6,212,182	$2,869,495	$14,805,301
		Sell offers	$1,324,669	$5,356,343	$2,536,234	$9,217,245
	Options	Buy bids	$0	$385,671	$189,479	$575,150
		Sell offers	$46,986	$2,119,631	$1,384,310	$3,550,927
Apr-20	Obligations	Buy bids	$790,059	$4,183,958	$1,529,936	$6,503,953
		Sell offers	$41,448	$2,776,189	$734,853	$3,552,490
	Options	Buy bids	$0	$166,392	$110,528	$276,920
		Sell offers	$24,751	$1,253,544	$677,821	$1,956,117
May-20	Obligations	Buy bids	($20,781)	$2,228,724	$942,289	$3,150,231
		Sell offers	$35,292	$1,156,210	$447,672	$1,639,174
	Options	Buy bids	$2,796	$24,557	$15,889	$43,242
		Sell offers	$6,653	$738,265	$354,859	$1,099,777
Jun-20	Obligations	Buy bids	$27,761,897	$11,387,702	$1,235,341	$40,384,940
		Sell offers	$522,757	$16,675,803	$9,108,134	$26,306,694
	Options	Buy bids	$34,116	$577,513	$278,460	$890,089
		Sell offers	$193,426	$4,818,477	$4,281,572	$9,293,476
Jul-20	Obligations	Buy bids	$10,769,326	$6,260,865	$12,724,621	$29,754,813
		Sell offers	$839,820	$6,455,401	$11,988,123	$19,283,344
	Options	Buy bids	$40,923	$697,068	$955,988	$1,693,979
		Sell offers	$109,743	$2,402,095	$3,647,950	$6,159,788
Aug-20	Obligations	Buy bids	$11,076,859	$1,985,772	$9,676,248	$22,738,879
		Sell offers	$548,721	$3,457,199	$10,686,371	$14,692,290
	Options	Buy bids	$9,471	$889,062	$1,194,634	$2,093,167
		Sell offers	$176,942	$2,268,717	$3,353,809	$5,799,468
Sep-20	Obligations	Buy bids	$10,907,926	$4,158,962	$11,628,905	$26,695,793
		Sell offers	$293,412	$5,420,086	$12,989,773	$18,703,271
	Options	Buy bids	$21,192	$504,574	$966,894	$1,492,660
		Sell offers	$76,632	$1,904,346	$2,733,954	$4,714,933
2019/2020*	Obligations	Buy bids	$133,437,559	$129,554,826	$45,741,569	$308,733,954
		Sell offers	$7,250,257	$132,773,410	$66,392,916	$206,416,583
	Options	Buy bids	$567,551	$13,430,803	$8,397,321	$22,395,675
		Sell offers	$1,210,460	$44,320,769	$26,237,313	$71,768,541
	Net Total		$125,544,393	($34,108,549)	($38,491,339)	$52,944,505
2020/2021**	Obligations	Buy bids	$60,516,008	$23,793,302	$35,265,115	$119,574,425
		Sell offers	$2,204,710.57	$32,008,489	$44,772,400	$78,985,599
	Options	Buy bids	$105,703	$2,668,216	$3,395,976	$6,169,895
		Sell offers	$556,743	$11,393,636	$14,017,286	$25,967,665
	Net Total		$57,860,257	($16,940,607)	($20,128,594)	$20,791,056

* Shows Twelve Months for 2019/2020 **Shows four months for 2020/2021

FTR Target Allocations

FTR target allocations were examined separately by source and sink contribution. Hourly FTR target allocations were divided into those that were benefits and liabilities and summed by sink and by source. Figure 13-6 shows the 10 largest positive and negative FTR target allocations, summed by sink, for the first four months of the 2020/2021 planning period. The top 10 sinks that produced financial benefit accounted for 35.8 percent of total positive target allocations with the Western Hub accounting for 8.8 percent of all positive target allocations. The top 10 sinks that created liability accounted for 15.3 percent of total negative target allocations with PSEG accounting for 4.0 percent of all negative target allocations.

Figure 13-6 Ten largest positive and negative FTR target allocations summed by sink: 2020/2021

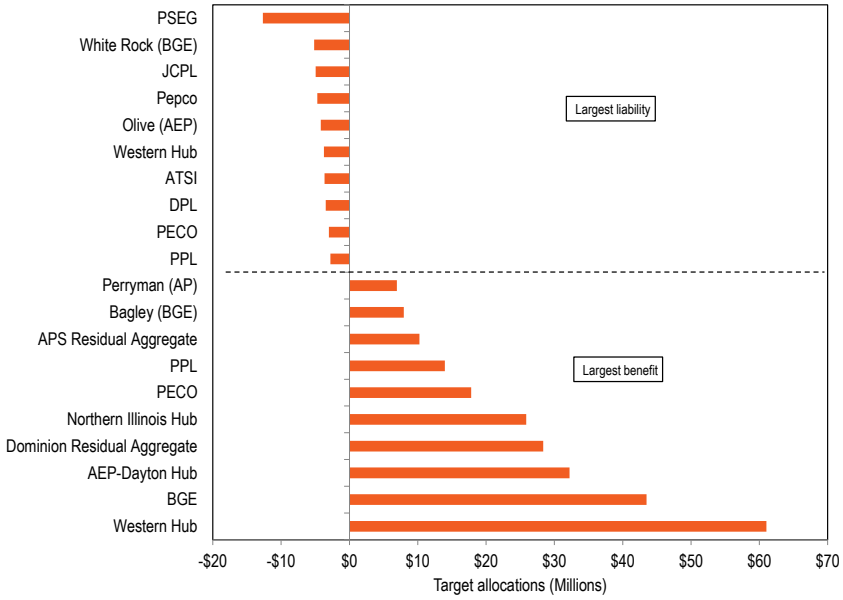
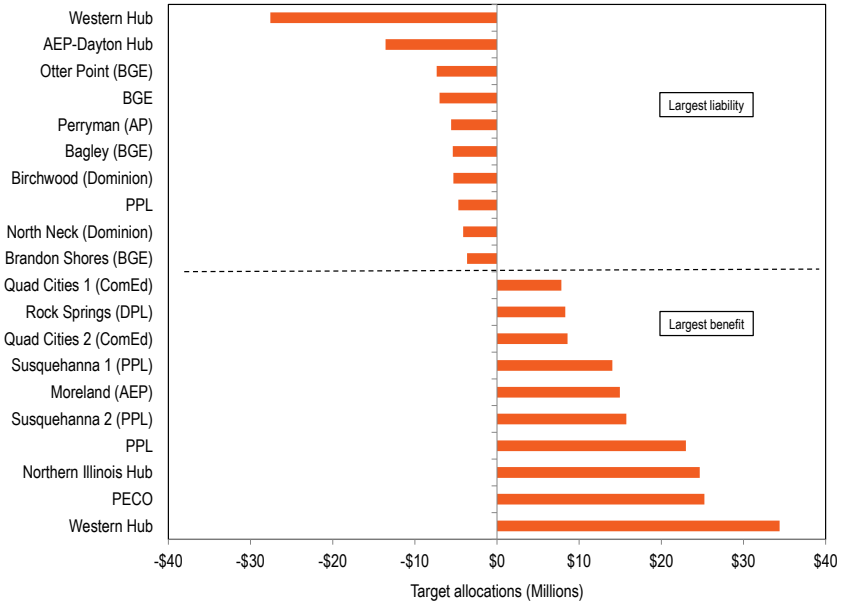


Figure 13-7 shows the 10 largest positive and negative FTR target allocations, summed by source, for the first four months of the 2020/2021 planning period. The top 10 sources with a positive target allocation accounted for 25.5 percent of total positive target allocations with the Western Hub accounting for 5.0 percent of total positive target allocations. The top 10 sources with a negative target allocation accounted for 26.7 percent of all negative target allocations, with the Western Hub accounting for 8.7 percent.

Figure 13-7 Ten largest positive and negative FTR target allocations summed by source: 2020/2021



Surplus Congestion Revenue

On May 31, 2018, a rule change was implemented. Effective for the 2018/2019 planning period, surplus day-ahead congestion and surplus FTR auction revenue are allocated to ARR holders.[38]

Surplus congestion revenue should be allocated to ARR holders because such revenue is part of total congestion revenues. In addition, FTR Auction revenue results from the prices paid by willing FTR buyers and should not be returned to FTR buyers for any reason.

Surplus day-ahead congestion is the difference between the day-ahead congestion collected and FTR target allocations. Surplus FTR auction revenue is the difference between the sum of monthly FTR auction revenue from the Long Term, Annual and monthly auctions, and ARR target allocations. Surplus FTR auction revenue can result from high prices in the FTR auctions, and can result from both FTR capacity sold in excess of assigned ARR capacity on specific paths, and FTR capacity sold on paths not available to ARR holders.

Surplus congestion revenue is the sum of the surplus day-ahead congestion revenue and the surplus FTR auction revenue at the end of each month. Beginning with the 2014/2015 planning period, may use surplus FTR auction revenue to pay for the clearing of counter flow FTRs as part of the auction clearing process.[39] The remaining surplus is first used to ensure that ARR target allocations in the month are fully funded. Any remaining surplus is used to pay any shortfall in FTR target allocations for the month. Any remaining surplus is used to pay any shortfall in FTR target allocations from prior months in the planning period. Any remaining surplus is used to pay any shortfall in FTR target allocations for subsequent months in the planning period. Any congestion surplus remaining at the end of the planning period is distributed to ARR holders based on their positive target allocations.

If, at the end of the planning period, all the surplus congestion revenue has been provided to FTR holders and target allocations for the year are not covered, an uplift charge is assigned to FTR holders to cover the net planning period deficiency. An individual participant's uplift charge allocation is the ratio of their share of net positive target allocations to the total net positive target allocations.

Prior to the 2017/2018 planning period, the surplus congestion revenue was not the simple sum of the surplus FTR auction revenue and surplus day ahead congestion because there were various cross market charges subtracted from FTR revenue, including M2M and competing use charges, which reduced available surplus congestion revenue.

Figure 13-8 shows the distribution of the total monthly surplus congestion and auction revenue distributed to FTR holders as if it were settled monthly. The figure shows the portions of total monthly surplus, represented by the total height of the bar, that are from day-ahead congestion surplus, represented by the blue portion of the bar, and from auction surplus, represented by the orange portion of the bar. The horizontal green lines represent the amount of revenue that FTRs were paid from the surplus to be made whole for that month. If there was day-ahead congestion surplus, FTRs were made whole through the surplus and the auction revenue was reserved for ARR holders. The height of the bar below the green line is the portion of auction surplus that went to FTR holders, and the height of the bar above the green line is the portion that would have gone to ARR holders at the end of the planning year, but only if nothing changed and this surplus was not provided to FTRs. If a green line is above the bar that means there was not enough surplus in that month to make FTRs whole, and that month will use surplus from previous or future months to make FTRs whole. For example, September 2020 did not have enough surplus to make FTRs whole. In settlements, those FTRs were made whole using surplus revenue from previous months, reducing the total surplus for the planning period. The final settlements will not be known until the end of the planning period.

The market rules should recognize that ARR holders have the right to all surplus congestion revenue, not just the remainder after funding FTRs. The MMU recommends that all FTR auction revenue and all surplus day-ahead

38 On May 31, 2018, FERC issued an order accepting PJM's proposal to allocate surplus day-ahead congestion charges and surplus FTR auction revenue that remain at the end of the Planning Period to ARR holders, rather than to FTR holders. 163 FERC ¶ 61,165 (2018).

39 *See* "PJM Manual 6: Financial Transmission Rights," Rev. 25 (July 23, 2020).

congestion revenue be distributed directly to ARR holders on a monthly basis. In Figure 13-8 the amount represented by each bar would be assigned to ARR holders in every month. In late 2018, there were high target allocations with low congestion collected, resulting in the allocation of most or all of the surplus congestion revenue to FTR holders. This is an indication that too many FTRs were sold. In the first four months of the 2020/2021 planning period, the rules resulted in the payment of $46.5 million of surplus congestion revenue to FTR holders that should have been paid to ARR holders.

Figure 13-8 Monthly surplus congestion and auction revenue distributed to FTR holders: June 2017 through September 2020[40]

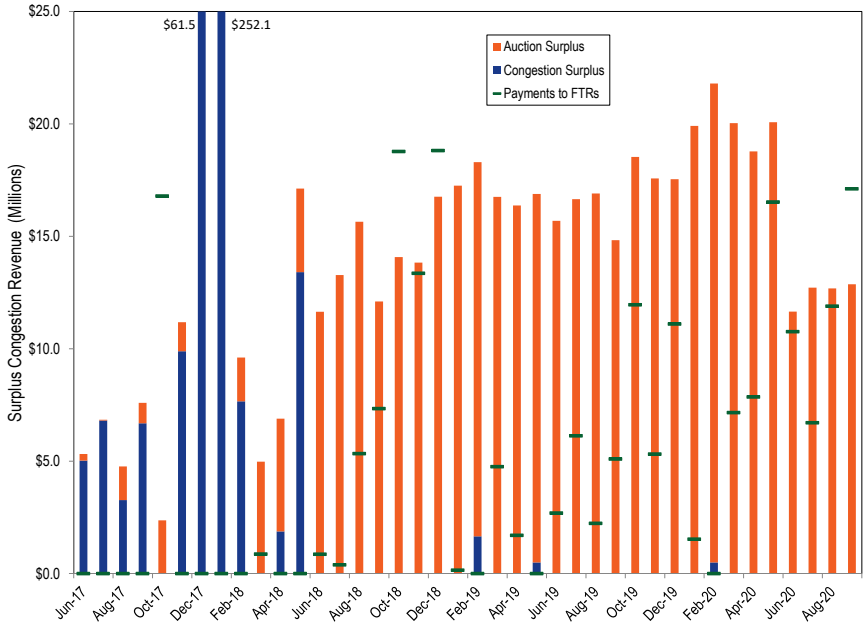
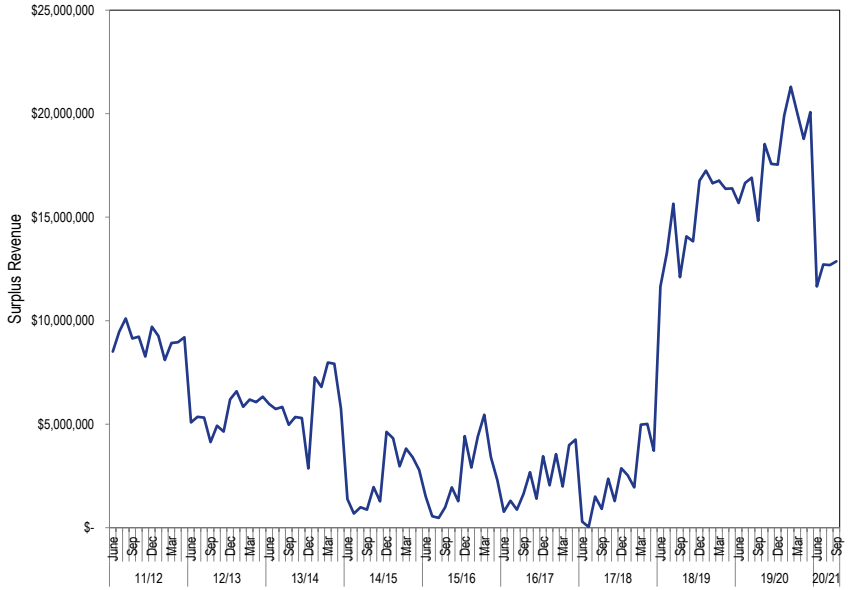


Figure 13-9 shows the surplus FTR auction revenue from the 2011/2012 planning period through the 2020/2021 planning period. Each new planning period introduces a new FTR model, including outages and PJM's discretionary adjustments for revenue adequacy. The differences in the assumptions in the market model can result in large differences in FTR auction surplus and ARR revenue from one planning period to another.

FTR auction revenue is the value that FTR buyers assign to congestion rights that belong to ARR holders. There is no logical or market based reason to assign any part of that auction revenue back to the FTR buyers. It is an unsupported wealth transfer. Auction revenue from the sale of FTRs should be distributed directly and completely to ARR holders. The MMU recommends that all FTR auction revenue be distributed to ARR holders on a monthly basis.

Figure 13-9 Monthly FTR auction surplus: 2011/2012 through 2020/2021



40 The bars for December 2017 and January 2018 are truncated.

Table 13-16 shows the surplus FTR auction revenue, surplus day-ahead congestion revenue and surplus congestion revenue for planning periods 2010/2011 through the first four months of the 2020/2021 planning period.

Table 13-16 Surplus FTR Auction Revenue: 2010/2011 through 2020/2021[41]

Planning Period	Surplus FTR Auction Revenue (Millions)	Surplus Day-Ahead Congestion (Millions	Surplus Congestion Revenue (Millions)
2010/2011	$29.7	($1,218.7)	($449.3)
2011/2012	$108.9	($460.3)	($192.5)
2012/2013	$66.7	($328.5)	($292.3)
2013/2014	$71.7	($715.3)	($678.7)
2014/2015*	$29.0	$139.8	$139.6
2015/2016	$29.6	$56.4	$42.5
2016/2017	$27.9	$97.1	$72.6
2017/2018	$27.4	$344.0	$371.2
2018/2019	$180.8	($68.5)	$112.3
2019/2020	$217.8	($87.9)	$140.7
2020/2021**	$49.9	($47.7)	$7.1
Total	$839.4	($2,289.5)	($726.8)

*Start of counter flow "buy back"
**First four months

Revenue Adequacy

FTR revenue adequacy simply compares congestion revenues to FTR target allocations. Revenue adequacy is not a benchmark for how well the FTR process is working. Target allocations define the maximum payments to FTRs but target allocations are not congestion. FTR revenue adequacy is not equivalent to the adequacy of ARRs as an offset for load against total congestion. A path specific target allocation is not a guarantee of payment.

Actual congestion revenues are unrelated to PJM's decisions about the FTR auction model. As a result, the fewer FTRs sold, the higher the probability that congestion will exceed the sum of the FTR target allocations. For example, PJM's subjective decision to reduce available system capability in FTR auctions for the 2014/2015 through 2016/2017 planning periods resulted in a high level of revenue adequacy. PJM's decisions have included the arbitrary use of higher outage levels and the decision to include additional constraints (closed loop interfaces) both of which reduced system capability in the FTR auction model. PJM's actions have led to a significant reduction in the allocation of Stage 1B and Stage 2 ARRs and therefore a reduction in available FTRs.

While PJM's arbitrary decision to increase outages in the ARR allocation and in the Annual FTR Auction reduced FTR revenue inadequacy, it did not address the Stage 1A ARR over allocation issue directly because Stage 1A ARR allocations cannot be prorated. PJM's actions for the 2014/2015 through 2016/2017 planning periods resulted in decreased Stage 1B ARR allocations, decreased Stage 2 ARR allocations and decreased FTR capability. The direct assignment of balancing congestion and M2M payments to load beginning in the 2017/2018 planning period increased the congestion revenue available to pay FTR holders. In response, PJM reduced the number of outages taken in the ARR allocation and in the Annual FTR Auction, increasing ARR allocations and FTR availability.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. There are several reasons for the disconnect between congestion revenues and ARR/FTR revenues in the current design. The reasons include: the use of generation to load paths rather than a measure of total congestion to assign congestion revenue rights; the failure to provide to ARR holders the full system capability that is provided to FTR purchasers in the Long Term FTR Auction; unavoidable modeling differences such as emergency outages; avoidable modeling differences such as outage modeling decisions; and cross subsidies among and between FTR participants and ARR holders.

The September 15, 2016, FERC order increased the gap between congestion revenue and ARR/FTR revenue collected. The result of allocating balancing congestion and M2M payments to load, and allocating surplus congestion revenue, which includes excess day-ahead congestion revenue and FTR auction revenue, solely to FTR holders, increased revenue to FTRs and reduced payments to load. The May 31, 2018, FERC Order, effective for the 2018/2019 planning period, assigned surplus congestion revenue to ARR holders and

41 Total congestion surplus not equal to the sum of the columns in years prior to the 2017/2018 planning period because other charges were subtracted from the congestion surplus.

increased payments to load, partially offsetting the impacts of the prior order.[42]

Revenue adequacy for ARRs is an almost meaningless concept. Revenue adequacy for ARRs means that FTR buyers collectively pay more than zero for FTRs in FTR auctions, and that those payments were received by ARR holders. Unsurprisingly, ARRs have been revenue adequate for every auction to date. ARR revenue adequacy has nothing to do with the adequacy of ARRs as an offset to total congestion. ARRs can be revenue adequate at the same time that ARRs return only half of congestion to load.

Total net FTR auction revenue for the 2019/2020 planning period, before accounting for self scheduling, load shifts or residual ARRs, was $982.0 million. The FTR auction revenue pays ARR holders' credits. For the first four months of the 2020/2021 planning period, total net FTR auction revenue was $670.5 million.

Table 13-17 presents the PJM FTR revenue detail for the 2019/2020 planning period and the first four months of the 2020/2021 planning period. This includes expected ARR target allocations from the Annual ARR Allocation and net revenue sources from the Long Term, Annual and Monthly Balance of Planning Period FTR Auctions. In this table, under the new balancing congestion and M2M payment rules, any negative congestion is from day-ahead congestion and does not include balancing congestion. A negative deficiency is a surplus, which will be distributed to ARR holders at the end of the planning period, while a positive deficiency is a shortfall, which will be charged as FTR uplift at the end of the planning period.

Table 13-17 Total annual PJM ARR and FTR revenue detail (Dollars (Millions)): 2019/2020 and 2020/2021

Accounting Element	2019/2020	2020/2021*
ARR information		
ARR target allocations	$752.2	$509.1
ARR credits	$752.2	$509.1
FTR auction revenue	$982.0	$670.5
Annual FTR Auction net revenue	$844.6	$577.0
Long Term FTR Auction net revenue	$84.5	$72.7
Monthly Balance of Planning Period FTR Auction net revenue	$52.9	$20.8
Surplus auction revenue		
ARR Surplus	$217.8	$49.9
ARR payout ratio	100%	100%
FTR targets		
Positive target allocations	$904.3	$452.8
Negative target allocations	($224.3)	($76.2)
FTR target allocations	$680.1	$376.6
Adjustments:		
Adjustments to FTR target allocations	($7.9)	($1.4)
Total FTR targets	$673.5	$375.2
FTR payout ratio	100%	100%
FTR revenues		
ARR excess	$217.8	$49.9
Congestion		
Net Negative Congestion (enter as negative)	$0.0	$0.0
Hourly congestion revenue	$596.4	$328.9
M2M Payments(credit to PJM minus credit to M2M entity)	$0.0	$0.0
Adjustments:		
Surplus revenues carried forward into future months	$0.0	$4.2
Surplus revenues distributed back to previous months	$0.0	$0.0
Other adjustments to FTR revenues	$0.0	$0.0
Total FTR revenues		
Surplus revenues distributed to other months	$0.0	$4.2
Net Negative Congestion charged to DA Operating Reserves	$0.0	$0.0
Total FTR congestion credits	$814.2	$383.0
Total congestion credits(includes end of year distribution)	$814.2	$383.0
Remaining deficiency	($140.7)	($7.9)

* First four months of 2020/2021 planning period

FTR target allocations are defined based on hourly CLMP differences in the day-ahead energy market for FTR paths. FTR credits are paid to FTR holders and, depending on market conditions, can be less than the target allocations but are capped at target allocations. Table 13-18 lists the FTR revenues, target allocations, credits, payout ratios, congestion credit deficiencies and excess congestion charges by month.

42 163 FERC ¶61,165 (2018).

The total row in Table 13-18 is not the sum of each of the monthly rows because the monthly rows may include excess revenues carried forward from prior months and excess revenues distributed back from later months. September 2020 had revenue shortfalls totaling $4.2 million, but were fully funded using excess revenue from previous months.

Table 13-18 Monthly FTR accounting summary (Dollars (Millions)): 2019/2020 and 2020/2021

Period	FTR Revenues (with adjustments)	FTR Target Allocations	FTR Payout Ratio (original)	FTR Credits (with adjustments)	FTR Payout Ratio (with adjustments)	Monthly Credits Surplus/Deficiency (with adjustments)
Jun-19	$52.1	$39.4	100.0%	$52.1	100.0%	($13.0)
Jul-19	$91.7	$82.0	100.0%	$91.7	100.0%	($10.5)
Aug-19	$57.1	$42.8	100.0%	$57.1	100.0%	($14.7)
Sep-19	$83.4	$73.6	100.0%	$83.4	100.0%	($9.7)
Oct-19	$91.1	$84.5	100.0%	$91.1	100.0%	($6.6)
Nov-19	$84.6	$72.3	100.0%	$84.6	100.0%	($12.3)
Dec-19	$80.6	$74.1	100.0%	$80.6	100.0%	($6.4)
Jan-20	$63.2	$44.8	100.0%	$63.2	100.0%	($18.4)
Feb-20	$50.0	$28.2	100.0%	$50.0	100.0%	($21.8)
Mar-20	$51.4	$38.5	100.0%	$51.4	100.0%	($12.9)
Apr-20	$42.9	$32.0	100.0%	$42.9	100.0%	($10.9)
May-20	$66.2	$62.7	100.0%	$66.2	100.0%	($3.5)
Summary for Planning Period 2018/2019						
Total	$814.2	$674.9		$814.2		($140.7)
Jun-20	$74.4	$73.3	100.0%	$74.7	100.0%	($1.1)
Jul-20	$118.3	$112.3	100.0%	$118.3	100.0%	($6.0)
Aug-20	$95.2	$94.4	100.0%	$95.2	100.0%	($0.8)
Sep-20	$90.9	$95.2	94.9%	$95.2	100.0%	$0.0
Summary for Planning Period 2019/2020						
Total	$378.8	$375.2		$383.4		($7.9)

Figure 13-10 shows the original PJM reported FTR payout ratio by month, excluding excess revenue distribution, for January 2004 through September 2020. The months with payout ratios above 100 percent have congestion revenue greater than the target allocations and the months with payout ratios under 100 percent have congestion revenue that is less than the target allocations. Figure 13-10 also shows the payout ratio after distributing surplus congestion revenue across months within the planning period. The payout ratio for revenue inadequate months in the current planning period may change if surplus congestion revenue is collected in the remainder of the planning period.

Figure 13-10 FTR payout ratio by month, excluding and including excess revenue distribution: January 2004 through September 2020

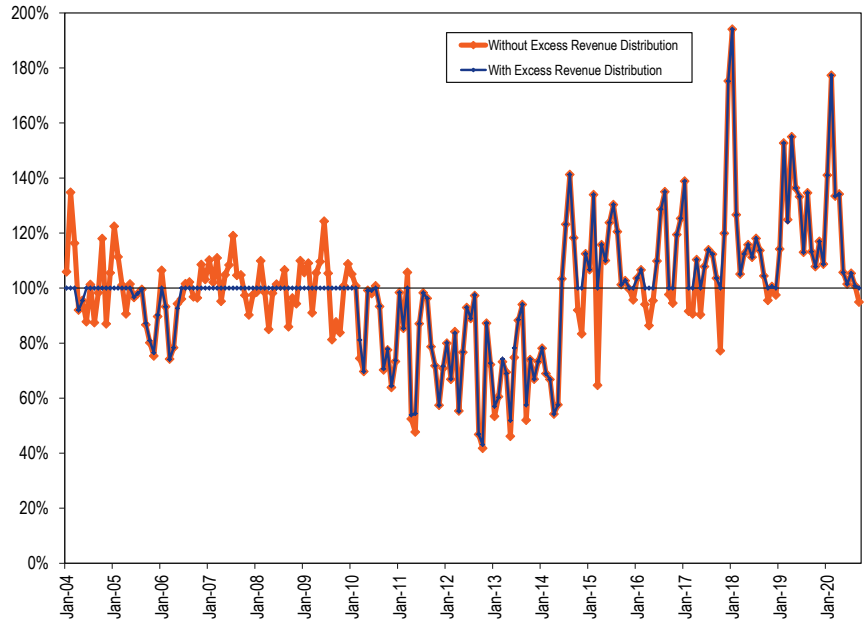


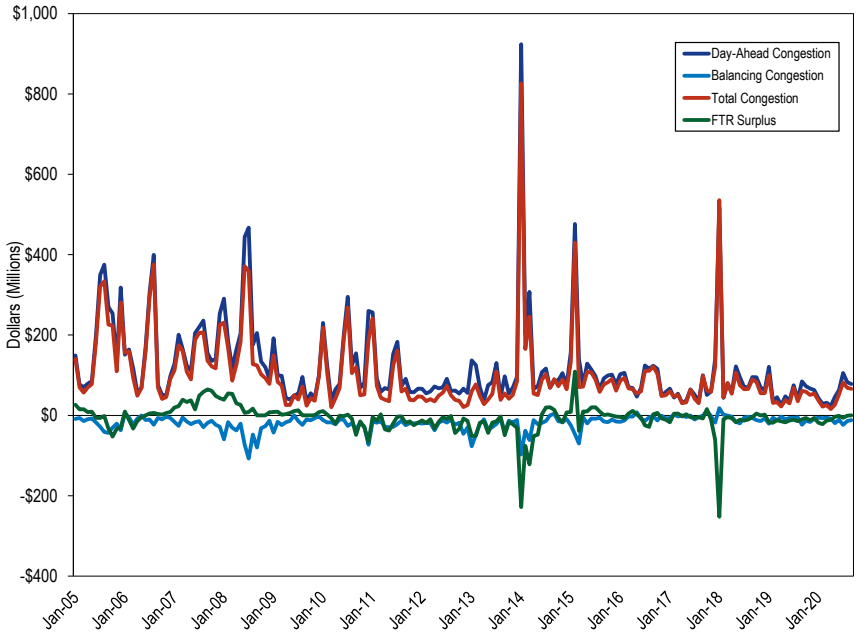
Table 13-19 PJM reported FTR payout ratio by planning period

Planning Period	FTR Payout Ratio
2003/2004	97.7%
2004/2005	100.0%
2005/2006	90.7%
2006/2007	100.0%
2007/2008	100.0%
2008/2009	100.0%
2009/2010	96.9%
2010/2011	85.0%
2011/2012	80.6%
2012/2013	67.8%
2013/2014	72.8%
2014/2015	100.0%
2015/2016	100.0%
2016/2017	100.0%
2017/2018	100.0%
2018/2019	100.0%
2019/2020	100.0%
2020/2021	100.0%

Table 13-19 shows the FTR payout ratio by planning period from the 2003/2004 planning period forward. Planning periods with a payout ratio over 100 percent are listed at 100 percent. Planning period 2013/2014 includes the additional revenue from unallocated congestion charges from Balancing Operating Reserves. For the 2014/2015, 2015/2016 and 2016/2017 planning periods, there was surplus congestion revenue paid to FTR holders pro rata in proportion to their net positive target allocations, resulting in a payout ratio of 116.2 percent, 106.8 and 113.1 percent for the planning periods.

Figure 13-11 shows the FTR surplus, day-ahead, balancing and total congestion payments from January 2005 through September 2020.

Figure 13-11 FTR surplus and day-ahead, balancing and total congestion: January 2005 through September 2020



ARRs as an Offset to Congestion for Load

Load pays for the transmission system and pays congestion revenues. FTRs, and later ARRs, were intended to return congestion revenues to load. With the implementation of the current, path based FTR/ARR design, the purpose of FTRs has been subverted. The inconsistencies between actual network solutions used to serve load and path based rights available to load cause a misalignment of congestion collected from ARR holders and the congestion that is collectable by the same ARR holders. These inconsistencies between actual network use and path based rights cause cross subsidies among ARR holders and between ARR holders and FTR holders. The result of this misalignment is individual zones with vastly different offsets due to cross subsidies between zones based on the location of their path based ARRs compared to their actual congestion costs.

Table 13-20 shows the ARR and FTR revenue paid to load, the congestion offset available to load with and without allocating balancing congestion to load and the congestion offset when surplus congestion revenue is allocated to load. Offsets highlighted are the actual offsets based on the effective rules in that planning period. The pre 2017/2018 offset is calculated as the ARR credits and the FTR credits excluding balancing congestion and M2M payments, divided by the total day-ahead congestion and the load share of balancing and M2M payments. The 103.6 percent payout ratio in the 2016/2017 planning period, which was the last planning period before balancing congestion was assigned to load, is likely due to PJM selecting an overly conservative ARR/FTR model to improve FTR revenue adequacy. The 2017/2018 offset is the sum of the ARR credits, adjusted FTR credits and the load share of balancing congestion and M2M payments. The post 2017/2018 offset is calculated identically to the 2017/2018 offset, but includes any surplus congestion revenue remaining in the planning period. FTRs are fully funded before ARR holders have access to the surplus, so in planning periods with revenue inadequacy there is no difference between 2017/2018 and post 2017/2018. In planning periods that are fully funded, the surplus goes to load, and provides an increased congestion offset.

The allocation of balancing congestion and M2M payments to load went into effect in the 2017/2018 planning period. If these rules had been in place beginning with the 2011/2012 planning period, ARR holders would have received a total of $1,305.1 million less in congestion offsets from the 2011/2012 through the 2018/2019 planning period. The total overpayment to FTR holders for the 2011/2012 through 2018/2019 planning period would have been $1,427.4 million.

If the surplus revenue available for the first four months of the 2020/2021 planning period were distributed to ARR holders, total ARR and self scheduled FTR revenue would offset 50.6 percent of total congestion costs for the first four months of the 2020/2021 planning period. The offset would be 50.2 percent without distribution of surplus revenue. For the 2019/2020 planning period, FTR bidders paid more in the auctions than the actual day-ahead target allocations for the same paths. This resulted in an offset over 100 percent because the resulting ARR value was greater than actual congestion costs. This had not happened previously, and was a result of an unexpected reduction in energy prices and in day-ahead target allocations. FTR prices were lower in the Annual FTR Auction, reducing the offset for the first four months of the 2020/2021 planning period.

Table 13-20 ARR and FTR total congestion offset (in millions) for ARR holders: 2011/2012 through 2020/2021

			Revenue				Pre 2017/2018 (Without Balancing)		2017/2018 (With Balancing)		Post 2017/2018 (With Surplus)	
Planning Period	ARR Credits	FTR Credits	Day Ahead Congestion	Balancing + M2M Congestion	Total Congestion	Surplus Revenue	Total ARR/ FTR Offset	Percent Offset	Current Revenue Received	Percent Offset	New Revenue Received	New Offset
2011/2012	$512.2	$249.8	$1,025.4	($275.7)	$749.7	($192.5)	$762.0	101.6%	$598.6	79.8%	$563.0	79.8%
2012/2013	$349.5	$181.9	$904.7	($379.9)	$524.8	($292.3)	$531.4	101.3%	$275.9	52.6%	$257.5	52.6%
2013/2014	$337.7	$456.4	$2,231.3	($360.6)	$1,870.6	($678.7)	$794.0	42.4%	$574.1	30.7%	$623.1	30.7%
2014/2015	$482.4	$404.4	$1,625.9	($268.3)	$1,357.6	$139.6	$886.8	65.3%	$686.6	50.6%	$715.0	52.7%
2015/2016	$635.3	$223.4	$1,098.7	($147.6)	$951.1	$42.5	$858.8	90.3%	$744.8	78.3%	$745.2	78.4%
2016/2017	$640.0	$169.1	$885.7	($104.8)	$780.8	$72.6	$809.1	103.6%	$727.7	93.2%	$763.8	97.8%
2017/2018	$427.3	$294.2	$1,322.1	($129.5)	$1,192.6	$371.2	$721.5	60.5%	$595.7	50.0%	$886.5	74.3%
2018/2019	$529.1	$130.1	$832.7	($152.6)	$680.0	$112.3	$675.93	99.4%	$530.8	78.1%	$626.3	92.1%
2019/2020	$542.0	$91.9	$612.1	($160.4)	$442.7	$140.7	$652.54	147.4%	$492.1	111.2%	$614.2	138.8%
2020/2021*	$124.4	$65.2	$328.9	($67.2)	$257.2	$7.9	$196.29	76.3%	$129.1	50.2%	$130.2	50.6%
Total	$4,579.9	$2,266.3	$10,538.4	($1,979.5)	$8,550.0	($284.6)	$6,692.0	78.3%	$5,355.6	60.8%	$5,794.8	67.3%

* Four months of 2020/2021 planning period

Table 13-20 demonstrates the inadequacies of the ARR/FTR design. The goal of the design should be to give the rights to 100 percent of the congestion revenues to the load.

The cumulative offset, beginning in the 2011/2012 planning period, is the sum of the revenue received for that planning period and all previous planning periods divided by the total congestion for that planning period and all previous planning periods. The cumulative shortfall is the cumulative difference between the ARR holders' revenue and the congestion they paid, for the planning period and prior planning periods.

Table 13-21 shows the cumulative offset and shortfall, assuming the rules implemented in the 2017/2018 planning period. The cumulative offset percentage has increased since the 2014/2015 planning period. However, the cumulative shortfall in dollars decreased only in the 2019/2020 planning period. The cumulative offset would have been 67.3 percent if the 2017/2018 surplus allocation rules had been in place for the entire period.

Table 13-21 ARR and FTR cumulative offset for ARR holders using 2017/2018 surplus allocation: 2011/2012 through 2020/2021

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	79.8%	($151.1)
2012/2013	68.6%	($400.0)
2013/2014	46.1%	($1,696.5)
2014/2015	48.1%	($2,339.1)
2015/2016	53.3%	($2,544.9)
2016/2017	58.9%	($2,561.9)
2017/2018	61.4%	($2,868.0)
2018/2019	64.0%	($2,921.8)
2019/2020	67.8%	($2,750.2)
2020/2021	67.3%	($2,877.1)

* Four months of 2020/2021 Planning Period

Table 13-22 shows the cumulative offset and shortfall using the rules that were effective in the given planning period to calculate the ARR/FTR revenue. The cumulative offset was 75.0 percent based on the rules that were in place for each planning period. Load has been underpaid by $2.2 billion from the 2011/2012 planning period through the first four months of the 2020/2021 planning period. The amount of underpayment would have been even greater, $2.9 billion, if the 2017/2018 surplus allocation rules had been in place.

Table 13-22 ARR and FTR cumulative offset for ARR holders using effective surplus allocation rules: 2011/2012 through 2020/2021

Planning Period	Cumulative Offset	Cumulative Shortfall (Millions)
2011/2012	101.6%	$12.3
2012/2013	101.5%	$18.9
2013/2014	66.4%	($1,057.7)
2014/2015	66.1%	($1,528.5)
2015/2016	70.3%	($1,620.9)
2016/2017	74.5%	($1,592.6)
2017/2018	70.5%	($2,189.5)
2018/2019	72.3%	($2,243.2)
2019/2020	75.8%	($2,071.6)
2020/2021*	75.0%	($2,198.7)

* Four months of 2020/2021 Planning Period

Zonal ARR Congestion Offset

ARRs are allocated to zonal load based on historical generation to load transmission paths, in many cases based on pre 1999 paths. ARRs are allocated within zones based on zonal base load (Stage 1A) and zonal peak loads (other Stages). ARR revenue is the result of the prices that result from the sale of FTRs through the FTR auctions. ARR revenue for each zone is the revenue for the ARRs that sink in each zone.

Congestion paid by load in a zone is the total difference between what the zonal load pays in congestion charges net of payments to the generation that serves the zonal load, including generation in the zone and outside the zone.[43]

Table 13-23 shows the day-ahead congestion and balancing congestion and M2M charges paid by load in each zone along with the congestion offsets paid to load: FTR auction revenue; self scheduled FTR revenue; and the allocation of end of planning period surplus.[44] The offset for the 2019/2020 planning period assigns the current surplus revenue at the end of the quarter to ARR holders Table 13-23 also shows payments by load for balancing congestion and M2M payments. The total congestion offset paid to load is the sum of all of those credits and charges.

The zonal offset percentage shown in Table 13-23 is the sum of the congestion related revenues (offset) paid to load in each zone divided by the total congestion payment made by load in each zone.

43 See "Constraint Based Congestion Calculations," PJM ARR FTR Market Task Force (July 17, 2020) <https://www.pjm.com/-/media/committees-groups/task-forces/afmtf/2020/20200722/20200722-item-03a-constraint-based-congestion-calculations.ashx>.

44 See *2019 State of the Market Report for PJM*, Volume 2, Section 11: Congestion and Marginal Losses

Table 13-23 Zonal ARR and FTR total congestion offset (in millions) for ARR holders: 2020/2021 planning period

Zone	ARR Credits	FTR Credits	Balancing+ M2M Charge	Surplus Allocation	Total Offset	Day Ahead Congestion	Balancing Congestion	M2M Payments	Total Congestion	Offset
AECO	$1.5	$0.0	($1.0)	$0.1	$0.5	$3.6	($0.8)	($0.2)	$2.7	19.6%
AEP	$13.2	$10.1	($10.4)	$1.3	$14.1	$59.4	($9.5)	($1.6)	$48.2	29.3%
APS	$11.0	$8.5	($4.0)	$0.8	$16.3	$22.2	($3.4)	($0.6)	$18.2	89.7%
ATSI	$6.8	$0.1	($5.5)	$0.3	$1.6	$26.5	($4.8)	($0.9)	$20.8	7.9%
BGE	$19.5	$1.2	($2.8)	$0.9	$18.9	$13.5	($2.2)	($0.4)	$10.9	172.5%
ComEd	$12.2	$4.4	($8.4)	$0.7	$8.8	$38.9	($6.4)	($1.3)	$31.1	28.3%
DAY	$2.0	$0.1	($1.5)	$0.1	$0.7	$6.1	($1.2)	($0.2)	$4.7	16.0%
DEOK	$8.1	$1.4	($2.3)	$0.4	$7.6	$9.3	($1.9)	($0.4)	$7.0	107.7%
DLCO	$1.9	$0.1	($1.2)	$0.1	$0.9	$4.1	($1.1)	($0.3)	$2.8	32.3%
Dominion	$2.4	$31.8	($9.0)	$1.0	$26.2	$41.2	($9.9)	($0.2)	$31.1	84.3%
DPL	$10.0	$2.4	($1.7)	$0.5	$11.2	$17.5	($1.8)	($1.4)	$14.3	78.0%
EKPC	$1.0	$0.0	($1.0)	$0.0	$0.1	$4.5	($0.9)	($0.2)	$3.5	1.5%
EXT	$0.2	$0.0	$0.0	$0.0	$0.2	$0.6	($1.0)	$0.0	($0.5)	(37.3%)
JCPL	$2.0	$0.0	($2.1)	$0.1	($0.0)	$8.3	($1.8)	($0.3)	$6.2	(0.6%)
Met-Ed	$1.1	$0.3	($1.3)	$0.1	$0.2	$11.0	($1.9)	($0.2)	$8.8	2.0%
OVEC	$0.0	$0.0	$0.0	$0.0	$0.0	$0.4	($0.1)	$0.0	$0.3	0.0%
PECO	$5.0	$0.1	($3.5)	$0.2	$1.8	$12.3	($2.6)	($0.5)	$9.1	20.0%
PENELEC	$2.0	$1.9	($1.4)	$0.1	$2.7	$7.7	($1.2)	($0.2)	$6.3	43.3%
Pepco	$8.6	$1.3	($2.5)	$0.4	$7.9	$10.8	($2.0)	($0.4)	$8.4	93.1%
PPL	$7.7	$1.4	($3.4)	$0.4	$6.1	$14.8	($2.5)	($0.5)	$11.7	52.2%
PSEG	$8.2	$0.0	($4.0)	$0.4	$4.5	$15.6	($3.2)	($0.6)	$11.8	38.2%
RECO	$0.1	$0.0	($0.1)	$0.0	($0.1)	$0.6	($0.3)	($0.0)	$0.3	(21.1%)
Total	$124.4	$65.2	($67.2)	$7.9	$130.2	$328.9	($60.5)	($10.5)	$257.9	50.5%

The total congestion offset paid to loads in the first four months of the 2020/2021 planning period would be 50.5 percent of congestion costs if the surplus revenue available were distributed to ARR holders.[45] The results vary significantly by zone. Loads in some zones, like BGE, receive substantially more in offsets than their total congestion payments. Loads in other zones, like ATSI, receive substantially less in offsets than their total congestion payments. The offsets are a function of the assignment of ARRs and the valuation of ARRs in the FTR auctions.

45 The 50.5 percent offset result is not exactly equal to 50.6 percent offset included in this section as a result of rounding.

Credit

There were three collateral defaults in the first nine months of 2020 for a total of $34,410. There were 22 payment defaults in the first nine months of 2020 not involving GreenHat Energy, LLC for a total of $31,796. GreenHat Energy accrued payment defaults of $15.6 million in the first nine months of 2020 for a total of $162.6 million in defaults to date, which will continue to accrue through May 2021, including the auction liquidation costs.[46] In addition, PJM added the settlement fee and claimant payee funds to the default allocation, resulting in allocations of $12.5 million and $5.0 million for a total of $180.1 million.

GreenHat Settlement Proceedings

On June 5, 2019, FERC issued an order that established a paper hearing and settlement judge procedures regarding the GreenHat liquidation waiver request.[47] FERC recognized "...there are multiple complexities associated with implementing the Waiver Order Directive that should be addressed in a paper hearing..."[48] Before the paper hearing began, FERC established a settlement procedure to "...encourage the parties to make every effort to settle their disputes before the paper hearing commences."[49]

By delegated order issued December 30, 2019, the Commission approved a settlement agreement between PJM and the interested parties.[50] The result of the settlement is a release of all claims of harm resulting from the July auction liquidation of GreenHat's portfolio, the payment of $12.5 million directly to

46 See the *2019 Quarterly State of the Market Report for PJM: January through June* for a more complete explanation of credit issues that occurred in 2019.
47 On June 21, 2018, GreenHat Energy, LLC was declared in payment default for non-payment of a $1.2 million weekly invoice on June 5, 2018. GreenHat had been declared in default twice earlier in June 2018 for two collateral calls totaling $2.8 million. Daugherty, Suzanne, email sent to the MC, MRC, CS, and MSS email distribution list, "Notification of GreenHat Energy, LLC Payment Default," (June 22, 2018).
48 See 167 FERC ¶ 61, 2019 at P 27 (2019).
49 See *Id.* at P 28.
50 See 169 FERC ¶ 61,260 (2019).

two participants, and payment of up to $5 million total to participants that can show economic harm from PJM's actions during the July auction.

This settlement, requiring up to $17.5 million in payments, will be recovered via the default allocation assessment fund, which is allocated to all PJM members in proportion to their total net bill.

Default Portfolio Considerations

Under the method applied to the GreenHat default, when an FTR participant defaults on their positions, their portfolio remains in the FTR market. This portfolio will continue to accrue revenues and/or charges and must be reconciled. The current method to reconcile defaulted portfolios is that, while the defaulting participant is barred from the market, PJM treats the positions as unchanged, lets the positions settle at day ahead prices, and charges any net losses to the default allocation assessment. This method exposes all members in PJM to an uncertain charge for the default allocation assessment that will not be known until those FTRs settle.

The MMU recommends cancelling the FTRs in the defaulting portfolio rather than holding or liquidating them. This would release the capacity in the portfolio back to the FTR market. The market would then decide the value of the capacity released and the timing of its release. There is no discretion necessary to settle the defaulted position and the losses are contained within the ARR/FTR market.

Cancellation of a defaulting portfolio does not change congestion. Cancellation of a defaulting portfolio can affect ARR/FTR funding as a result of changes in auction revenue, changes in the net target allocations, and potential simultaneous feasibility violations, while any collateral collected from the defaulted participant is available to offset losses from the cancelled FTRs. However, PJM can and does address similar issues routinely. PJM has tools available, such as the counter flow buyback and Stage 1A over allocation rules, and uses them regularly in the Annual FTR Auction, to improve funding as well as address feasibility concerns. Cancellation of FTRs isolates the costs of the default to those participating in and benefitting from the FTR market.

FTR Forfeitures

Hourly FTR Cost

When the FTR forfeiture rule is triggered, only the related hourly profits are forfeited. Only the profit is forfeited and only for the hours in which the rule is violated. The rule does not impose a penalty, but only the return of the profit associated with the rule violation. The profit is calculated as the hourly FTR target allocation minus the FTR's hourly cost.

FERC Order on FTR Forfeitures

Effective January 19, 2017, a modified FTR forfeiture rule was applied.[51] This rule considers the impact of a participant's net virtual transaction portfolio on all constraints. If a participant's net virtual portfolio impacts a constraint by the greater of 0.1 MW or 10 percent or more of the line limit, and that constraint affects an individual FTR's target allocation by $0.01, the FTR is subject to FTR forfeiture if the net virtual portfolio increased the value of the FTR. FTR forfeitures do not result from net virtual portfolios that decrease the value of their affiliates' FTRs. The forfeiture amount calculation is the hourly profit of the FTR and an FTR cannot forfeit more than once per hour.

Figure 13-12 shows the monthly FTR forfeitures under the modified FTR forfeiture rule from January 19, 2017, through September 30, 2020. As required by the FERC order, PJM began retroactively billing FTR forfeitures with the September 2017 bill. In the period from January 2017 through September 2017, participants did not have good information about the level of their FTR forfeitures, so they could not accurately modify their bidding behavior to avoid FTR forfeitures. After September 2017, FTR forfeitures decreased significantly, and stabilized, as participants received information on their FTR forfeitures.

On June 24, 2019, PJM implemented a new method to properly calculate the hourly cost of an FTR only for hours in which it is effective.[52] Beginning with the September 2019 bill, PJM began billing using the correct hourly cost

51 See *2019 State of the Market Report for PJM*, Volume 2, Section 13: Financial Transmission Rights for the history.
52 See "Minor modification to Tariff Language for FTR Forfeiture Rule," Docket No. ER19-2240 (June 24, 2019).

calculation. For the period of January 19, 2017, through September 30, 2020, total FTR forfeitures were $22.1 million.

Figure 13-12 Monthly FTR forfeitures for physical and financial participants