THE ROLE OF AUCTION REVENUE RIGHTS IN MARKETS FOR FINANCIAL TRANSMISSION RIGHTS

by

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A Dissertation

Submitted to the Faculty of Purdue University

In Partial Fulfillment of the Requirements for the degree of

Doctor of Philosophy

Department of Agricultural Economics

West Lafayette, Indiana

August 2019

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ACKNOWLEDGMENTS

I thank Paul Preckel for his patience, support, and guidance throughout the development of this dissertation. Dr. Preckel is a class act in the role of advisor, and I am lucky to also call him a friend.

Thank you to Doug Gotham and Andrew Liu for helping refine my raw ideas into the three essays in this dissertation. I also thank Otto Doering, Wally Tyner, and Michael Wetzstein for their mentorship and friendliness throughout my time at Purdue.

A shout out to my fellow graduate students Brian Bourquard, David Boussios, Eric Gerber, Tanner McCarty, Will McClain, Jose Nuno-Ledesma, Stacy Prieto, Tim Smith, Sofia Vielma, and Brandon Weiland for all the memories and making our time together in Indiana as enjoyable as possible.

Special thanks to Devendra Canchi and Juan Giraldo for cultivating my interest in electricity markets and always encouraging me to press forward.

To Whitney Hodde, who endured my countless stressful nights and was always a source of encouragement and inspiration.

And finally, thank you to my family for the enduring support during my time in graduate school, I love you all.

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ABSTRACT

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Institution: Purdue University
Degree Received: August 2019
Title: The Role of Auction Revenue Rights in Markets for Financial Transmission Rights
Committee Chair: Paul V. Preckel

Financial Transmission Rights (FTRs) have been a feature of competitive electricity markets for nearly 20 years. FTRs are financial derivatives sold in periodic auctions. Revenues from the sale of these derivatives are passed through to electricity ratepayers to compensate them for transmission congestion payments they make in the spot energy market. FTR purchasers are effectively swapping their auction payment for an uncertain revenue stream over the life of the FTR. In recent years, industry market monitors have become concerned with the auctions' performance in adequately compensating ratepayers – FTRs sell, on average, for a price less than the revenue they generate for the purchaser. This dissertation contributes to our understanding of FTR market functioning by studying the Auction Revenue Rights (ARR) management process, which is the predominate mechanism used in U.S. electricity markets to distribute FTR auction revenue to electricity ratepayers. This dissertation is organized into three essays, detailed below.

The first essay demonstrates how the ARR process influences fundamental supply conditions in the FTR auction market and show how divergent auction equilibria emerge under different ARR decision-making regimes. Using market data from the PJM Interconnection, this essay finds empirical evidence that variation in ARR management strategies helps explain differences between an FTR's auction price and its realized *ex post* value.

The second essay studies the interaction of affiliated subsidiaries in auctions for FTRs. The essay documents a setting where a regulated utility routinely sells FTRs (through the ARR process)

to an affiliated generation company in an auction where a portion of the revenue is passed through to the regulated utility's retail customers. It appears that the affiliated generator may be placing strategic bids in the auction to minimize the price they pay for the derivatives, which would also minimize the revenue passed through to the regulated utility's retail customers.

The third essay studies the relationship between the long-term FTR auction market and the annual auction market in terms of ARR prices. Long-term auction clearing prices systematically overvalue FTRs that are along the paths of an ARR, thus providing electricity ratepayers with a biased signal of the potential value of their ARR allocations.

Collectively, these three essays demonstrate the role of the ARR process in determining equilibrium FTR auction prices. Not only do ARR management decisions directly affect equilibrium prices, but ARRs constitute the mechanism by which auction revenues are passed through to ratepayers. Thus, any analysis of FTR auction revenue deficiency must include a thorough understanding and empirical incorporation of the ARR process into the analysis.

CHAPTER 1. INTRODUCTION

1.1 Introduction

> "The peculiarities and complexities of the [FTR] auction can create opportunities for participants to routinely extract payments from ratepayers. The majority of these payments are from ratepayers to purely financial entities seeking to profit from participation in the auction, rather than suppliers that may be seeking to hedge risks related to day-ahead market schedules."

California ISO Department of Market Monitoring (2017)

For nearly 20 years, participants in competitive electricity markets have been able to purchase a financial derivative called a Financial Transmission Right (FTR). FTRs are considered a fundamental component to efficient electricity market operation because they serve as a hedging device by both power producers and load-serving entities (LSEs). Yet, FTRs' existence has been underscored by multiple controversies. Among FTRs' controversies is this: they tend to sell at a price in the auction that is less than what the FTR ends up being worth (Leslie, 2018; Olmstead, 2018). This is an important issue because the revenue raised in FTR auctions is passed through to electricity ratepayers, meaning lower auction prices translate to lower revenue pass-through to electricity ratepayers via their electricity bills.

Why do FTRs sell for a price less than their realized value? We begin with the conceptual idea that financial speculators who trade FTRs demand, on the margin, a trading premium for purchasing a risky asset. The reason for the trading premium is a combination of a risk premium and transaction costs associated with trading such a complex product. However, a trading premium demanded by FTR buyers alone is not enough to understand price formation in FTR auctions. For a comprehensive understanding of FTR auction price formation, we must also consider the supply side of the FTR auction market. In most U.S. competitive electricity markets, the supply side of FTR auctions is determined by something called the Auction Revenue Rights (ARR) process. Essentially, an ARR grants its holder the option to claim an FTR for themselves or to sell the FTR in an FTR auction and claim the associated revenue from the FTR's sale. It is true that auction participants can contribute to market supply by placing bids for counterflow FTRs, but FTRs that are marketed through the ARR process have a reservation price of $0, meaning they are the cheapest portion of supply available in the auction. Thus, the decisions made by ARR holders determine the quantity of FTR supply available in the auction with no reservation price.

This dissertation consists of three essays, each focusing on a different aspect of the ARR process. The first essay, entitled "Price Formation in Auctions for Financial Transmission Rights," provides a conceptual framework for understanding the role of ARRs in determining equilibrium FTR auction prices. The essay includes an empirical section which explores whether variation in ARR management strategies across ARR paths helps explain differences between an FTR's auction price and its realized value. The second essay, entitled "Potential Cross-Subsidization in PJM ARR/FTR Mechanism," studies the interaction of affiliated subsidiaries in FTR auctions, where a regulated subsidiary sells FTRs to an unregulated subsidiary through the ARR process. Finally, the third essay, entitled "Rent-Seeking in PJM's Long-Term FTR Auction," connects the ARR process to alternative FTR auctions to further understand the role of ARRs as a fundamental source of market supply in FTR auctions.

While most U.S. electricity markets use an ARR process, this dissertation focuses on the ARR process in the PJM Interconnection. The reason for this is twofold: 1) PJM is the largest electricity market in the U.S., and 2) PJM provides a rich source of publicly available data related to FTR auctions and the ARR process. Even though there are subtle differences across markets regarding ARR processes, the broad findings in this dissertation should generalize to other markets that use an ARR process.

Sections 1.2 and 1.3 in this chapter provide the necessary institutional details for understanding the three essays in this dissertation. The following section describes the role of FTRs within competitive electricity markets and defines the payoff structure of FTRs and ARRs. The subsequent section provides a mathematical formulation of the optimization model that is used to determine transactions and market clearing prices for FTR auctions.

1.2 Competitive Electricity Markets, Financial Transmission Rights, and Auction Revenue Rights

Competitive wholesale electricity markets are based on a system of locational marginal prices (LMPs). An independent system operator (ISO) collects offers from generators to produce power and bids from LSEs to consume power and then solves an economic dispatch optimization problem to settle the market. The essence of economic dispatch is that it selects the least-cost, or welfare-maximizing, mix of generation resources to meet electricity demand subject to available resources. Coordination of power flows by an ISO to achieve least-cost dispatch guarantees the transmission network is used most efficiently. Efficient use of the transmission network in a competitive setting cannot be achieved without the coordination of an ISO (or similar entity) because electricity travels according to Kirchoff's Laws, which makes the enforcement of physical property rights to transmission capacity impractical on an interconnected grid.

In an LMP system, generation resources are dispatched in merit order in terms of marginal delivery cost, starting with the cheapest units. When a transmission element reaches its rated carrying capacity, the ISO may have to dispatch a generation resource out of merit order to avoid damaging the transmission element. In the economic dispatch optimization problem, this limiting transmission element is called a binding transmission constraint. In the absence of binding transmission constraints, all LMPs (ignoring losses) will equal to the same price throughout the network, namely the marginal cost of generation. Whenever there is a binding transmission constraint in the economic dispatch problem, LMPs at each node will reflect the opportunity cost of scarce transmission capacity in addition to the marginal cost of generation. In general, prices at load nodes will increase and prices at generator nodes that contribute to congestion will decrease.

LMPs are made up of two components other than congestion: energy and losses. The energy component price represents the marginal cost of energy in the system, and is the same at every node on the network. The loss component represents the value of energy that was lost through the transmission of power from generators to load, and varies across nodes. This dissertation ignores losses because losses are the smallest in magnitude of the three LMP components. Moreover, considering the loss component of LMP would increase the complexity of the mathematical models and exposition without affecting the broad findings of the analysis.

The nodal price fluctuations faced by market participants due to congestion represent price risk. Generators and power utilities often engage in bilateral contracts or purchase futures contracts to mitigate this price risk. However, these contracts are typically settled at a node that is different from the node at which the generator or load settles physical power transactions with the ISO. Market participants must forward contract at nodes different from their own because there are thousands of nodes and forward contracts at each individual node would be too thinly traded. So, after forward contracting for energy, generators and load face locational basis risk which cannot be hedged with bilateral contracts or exchange-traded products. To fill this gap, most ISOs act as counterparties to a hedging product called a Financial Transmission Right (FTR) which can be used as a hedge against locational basis risk.

1.2.1 *Financial Transmission Rights*

An ISO sells FTRs in periodic auctions up to three years before the FTR begins generating cash flows. Market participants submit bid schedules to buy (or offers to sell previously acquired) FTRs. A schedule is a series of bids where each bid includes a source node, a sink node, a MW quantity, a reservation price, and potentially other classifications (e.g. on-peak hours or off-peak hours and a particular month or season). There are no restrictions as to which nodes can be source or sink nodes, nor do source or sink nodes need to correspond to where generators or load physically reside on the network.

A mathematical programming model whose objective function is to maximize the FTR auction revenue determines auction-clearing prices. The following section provides a mathematical formulation of the FTR auction problem. The mathematical program that determines cleared transactions in the FTR auction calculates a price for every source/sink combination simultaneously. The auction-clearing price for an FTR is the nodal price difference between the source and the sink determined in the auction:

$$\text{FTR Auction Price } \left(\frac{\$}{\text{MW}}\right) = P_{Auction}^{Sink} - P_{Auction}^{Source}, \tag{1.1}$$

where $P_{Auction}^{Sink}$ is the nodal price at the sink node in the auction, and $P_{Auction}^{Source}$ is the nodal price at the source node in the auction.

The payoff to an FTR is determined in the day-ahead energy market over the time period that the FTR covers. The payoff, called the Target Allocation, is defined as the difference between the congestion components of LMP in the day-ahead energy market for every hour the FTR is a valid obligation (as defined by the contract):

$$\text{FTR Target Allocation } \left(\frac{\$}{\text{MW}}\right) = \sum_{t \in T} \left(P_t^{Sink} - P_t^{Source}\right), \tag{1.2}$$

where t is the index of hours during which the FTR is a valid obligation as defined by set T, P_t^{Sink} is the congestion component of LMP at the sink node in hour t, and P_t^{Source} is the congestion component of LMP at the source node in hour t. At the time of the auction, an FTR's Target Allocation is uncertain. Because the bidder specifies a quantity (in MW) for an FTR contract, the payout for a contract is calculated by multiplying the FTR Target Allocation times the contract quantity.

In general, an FTR is called prevailing flow if its auction price is positive and counterflow if its auction price is negative. A positive price suggests that net power flows tend to move from the source to the sink as defined by the FTR. A negative price suggests that net power flows tend to move from the sink to the source as defined by the FTR, hence 'counterflow.' In effect, when a market participant purchases a counterflow FTR, the market participant is paid some amount of money from the auction to hold an FTR which has a negative expected cash flow.

1.2.2 *Auction Revenue Rights*

We focus on electricity markets that use Auction Revenue Rights to distribute auction revenues to market participants.[1] In general, ISOs allocate ARRs to LSEs who schedule firm or non-firm point-to-point transmission service for the upcoming planning period. An ISO allocates ARRs along specific source/sink paths and in specific MW quantities. The source node of an ARR usually corresponds to a generating resource in the LSE's service territory, while the sink node is usually an aggregate node type which is a weighted average index of load nodes. The holder of an ARR can either claim revenue from the auction or convert the ARR into an FTR. The revenue awarded to an ARR holder in the annual FTR auction is:

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[1] The ARR system is used by ISO-New England, Midcontinent Independent System Operator, PJM, and Southwest Power Pool.

$$\text{ARR Auction Revenue (\$)} \;=\; Q \times \left(P_{Auction}^{Sink} - P_{Auction}^{Source}\right), \tag{1.3}$$

where Q is the quantity (in MW) of ARRs being claimed as auction revenue and auction prices are calculated as before. In PJM, the annual auction occurs in April and consists of four rounds. There is approximately one week between rounds, with results from one round posted before the start of the next round. The sink and source prices used in (1.3) are simple averages across the four rounds. If the ARR holder chooses to self-schedule their ARRs into FTRs, then the payout for the resulting FTRs (i.e. Target Allocation) is the same as in (1.2), where the sink node is the LSE's aggregate sink node and the generator node is the source node.

An ARR holder must choose whether they will claim auction revenue or self-schedule into FTRs before the commencement of the annual auction. Thus, both auction revenue and revenue from FTR holdings are uncertain at the time of the decision. Further, the ARR holder is not able to set a 'strike price' or otherwise construct a supply curve for self-scheduling FTRs conditional on the auction clearing price.

An ARR holder can diversify their ARR allocation by claiming a fraction of the quantity of an ARR allocation as auction revenue and self-scheduling the remaining fraction as FTRs. When an ARR holder chooses to diversify their auction revenue/self-scheduling decision, the payoff becomes:

$$\text{ARR Allocation Payoff (\$)} =$$
$$Q \times \left\{\alpha \times \left(P_{Auction}^{Sink} - P_{Auction}^{Source}\right) + (1-\alpha) \times \sum_{t=1}^{T} (P_t^{Sink} - P_t^{Source})\right\}, \tag{1.4}$$

where α is the fraction of the ARR allocation claimed as auction revenue. Again, note that both components of the payoff (ARR Auction Revenue and FTR Target Allocation) are uncertain when the ARR holder chooses the proportion to claim as auction revenue versus as FTR. At the point in time where the ARR holder chooses the strategy embodied in α, both the auction revenue and the

FTR payoff are random variables. If these random variables are not perfectly correlated, then an interior solution with $0 < \alpha < 1$ could be optimal for a risk-averse agent.

How ARRs are allocated to LSEs or other transmission customers varies across RTOs/ISOs (Bosquez Foti, 2016). In general, ARRs are allocated to market participants who acquire Network Integration Transmission Service or Firm Point-to-Point transmission service through the Open Access Same-Time Information System (Ma et al., 2002). These two types of market participants pay for the construction and maintenance of the transmission system; so, they are allocated ARRs for the purpose of offsetting the expected congestion rent that they incur in the day-ahead energy market.

The following section provides a mathematical formulation of the FTR auction problem used to determine auction clearing prices for all potential source/sink combinations on the network.

1.3 FTR Auction Optimization Model with Auction Revenue Rights

Consider a transmission network composed of the set $i = \{1, \ldots, N\}$ nodes and the set $k = \{1, \ldots, K\}$ transmission lines. The normal line rating of transmission line k is denoted by L_k. The shift factor matrix for the network is denoted by $f_{k,i}$, where the k,i^{th} element refers to the impact of a 1 MW injection at node i on line k. We simplify our formulation by ignoring sell offers, emergency transmission constraints, losses, and other details such as hour types (e.g. on-peak vs. off-peak hours).

FTR auction participants submit a bid to purchase an FTR which consists of four elements: 1) a source node i; 2) a sink node j; 3) a maximum quantity $\bar{q}_{i,j}$; and 4) a bid price $p_{i,j}$. Thus, a bid is defined by the indexed pair $(p_{i,j}, \bar{q}_{i,j})$ The set of all bids submitted to the auctioneer is denoted by Ψ. If there is no bid for a particular source/sink pair, then $\bar{q}_{i,j}$ = 0 for that pair. Table 1 summarizes the nomenclature used in the mathematical formulation of the FTR auction model.

We augment the optimization model to include FTRs that are allocated to LSEs through the ARR process. Intuitively, transmission capacity needs to be "reserved" for self-scheduled FTRs to ensure that the self-scheduled FTRs are simultaneously feasible with the FTRs that are sold in the auction. We incorporate the ARR process into the optimization model using two parameters, $A_{i,j}$ and $\alpha_{i,j}$. The variable $A_{i,j}$ refers to the quantity (in MW) of an ARR allocated to an LSE from source i to sink j, while $\alpha_{i,j}$ refers to the proportion of the ARR allocation between source i to sink j that is claimed as auction revenue by the LSE (not self-scheduled as an FTR).

The objective function of the auction is to maximize bid-based revenue generated by the bids that clear the auction. The load balance constraint ensures that total injections into the network equal total withdrawals while the simultaneous feasibility conditions ensure that the set of cleared bids and self-scheduled FTRs respect the physical limitations of the transmission network.

Table 1 Notation for FTR Auction Optimization Program

i,j	Index for nodes in set N
k	Index for transmission lines
$\bar{q}_{i,j}$	Bid quantity (MW) for FTR with source node i and sink node j
$p_{i,j}$	Bid price ($/MW) for FTR with source node i and sink node j
Ψ	Set of bids entered into the auction, each bid consisting of a source i, sink j, quantity $\overline{q_{i,j}}$, and bid price $p_{i,j}$
$q_{i,j}$	Variable quantity (in MW) from source node i to sink node j
$f_{k,i}$	Change in power flow on line k due to 1 MW injection at node i (i.e. shift factor matrix)
L_k	Normal line rating for transmission line k
$A_{i,j}$	Quantity (MW) associated with an ARR allocation with source node i and sink node j
$\alpha_{i,j}$	Proportion of ARR allocation with source node i and sink node j claimed as auction revenue
C_i	Market clearing price at node i
λ_k	Shadow price on the simultaneous feasibility condition for line k

Objective function:

$$\max_{\{q_{i,j} \leq \bar{q}_{i,j} \in \Psi\}} \sum_{i \in N} \sum_{j \neq i} p_{i,j} q_{i,j} \tag{1.5}$$

Load Balance:

$$\sum_{i \in N} \left(\sum_{j \neq i} \left(q_{i,j} + \left(1 - \alpha_{i,j}\right) A_{i,j} \right) - \sum_{j \neq i} \left(q_{j,i} + \left(1 - \alpha_{j,i}\right) A_{j,i} \right) \right) = 0 \tag{1.6}$$

Simultaneous Feasibility Conditions, ∀ *k* transmission lines:

$$-L_k \leq \sum_{\mathrm{i}=1}^{\mathrm{n}} f_{k,i} \left\{ \sum_{j \neq i} \left(q_{i,j} + \left(1 - \alpha_{i,j}\right) A_{i,j} \right) - \sum_{j \neq i} \left(q_{j,i} + \left(1 - \alpha_{j,i}\right) A_{j,i} \right) \right\} \leq L_k \qquad : \lambda_k \tag{1.7}$$

Bid Constraints, ∀ *i,j*:

$$0 \leq q_{i,j} \leq \bar{q}_{i,j} \tag{1.8}$$

The clearing price for any source/sink pair on the network (regardless of whether there was a bid for that FTR) is calculated by subtracting the nodal price of the sink from the nodal price of the source. The nodal price C_i for any node *i* on the network is calculated using the shadow prices determined in the optimization program and the shift factor matrix:

$$C_i = \sum_{\mathrm{k}=1}^{\mathrm{K}} f_{k,i} \lambda_k. \tag{1.9}$$

CHAPTER 2. PRICE FORMATION IN AUCTIONS FOR FINANCIAL TRANSMISSION RIGHTS

2.1 Introduction

Since the passage of FERC Order 888 in 1996, competitive electricity markets have expanded in the United States to serve roughly two-thirds of electricity consumers in the country. The Order encouraged open access to transmission facilities, the divestiture of vertically integrated utilities, and the creation of Independent System Operators to administer competitive markets. A key feature of competitive electricity markets is a location-based pricing system. For competitive market participants, location-based pricing implies location-specific price risk due to potential network congestion that can cause price differences across nodes. The presence of uncertain network congestion inspired the creation of a financial product to hedge locational price differences (Hogan, 1992). In U.S. electricity markets, this financial product is called a Financial Transmission Right (FTR). These financial products are used by market participants to manage exposure to the risk of price differences between two locations on a transmission network.

FTRs are sold in auctions administered by an Independent System Operator. The revenue raised in these auctions is allocated to load-serving entities (LSEs) to reimburse their electricity customers for expected congestion payments they will incur in the energy market. However, recent analysis shows that FTR auctions are persistently profitable for speculators, and that, on average, electricity customers are not fully reimbursed for their congestion payments.[2] One common explanation for the auction revenue shortfall is that the FTR auction process is inefficient (Deng

[2] The work of the California ISO's Department of Market Monitoring and PJM's independent market monitor highlight this fact and has received attention in their respective ISO/RTO stakeholder processes (California ISO, 2016; Monitoring Analytics, 2017). See also Leslie (2018).

et al., 2010; Olmstead, 2018).[3] In this chapter, we propose an alternative explanation for persistent congestion reimbursement shortfalls, which is the role of trading premiums demanded by auction participants. Essentially, the trading premium of an FTR adjusts the FTR's bid price to account for the market participant's risk aversion and/or transaction costs.

Previous studies have examined the efficiency of FTR auctions (Adamson et al., 2010; Deng et al., 2010; Olmstead, 2018) and analyzed the presence of abnormal returns in FTR markets (Baltadounis et al., 2017). Our main contribution is a conceptual and empirical analysis of the market mechanism used to reimburse electricity customers for their expected congestion payments. This mechanism, called the Auction Revenue Right (ARR) process, gives an LSE a choice between acquiring an FTR at no cost or selling the same FTR in the annual FTR auction and receiving the associated auction revenue. Given that the choices made by LSEs in the ARR process determine fundamental supply conditions in the FTR auction market, we develop a conceptual framework that describes how different auction equilibria emerge under different ARR decision-making regimes. A key insight is that even if the FTR auction market is fully competitive, an LSE selling an FTR through the ARR process may result in a financial transfer from electricity customers to FTR buyers through a buyers' trading premium. One component of the trading premium is a risk premium adjustment due to the extreme difficulty in forecasting the future payout of an FTR.

We test the predictions from our conceptual model using data from the PJM market. PJM is a wholesale electricity market in the eastern United States serving 65 million customers. We study ARR management strategies and outcomes in PJM using publicly available data on auction results, realized network congestion, auction participant classifications, and various other

[3] Olmstead's description of inefficiency relies on the observation that FTR auction price are on average lower than FTR realized values in Ontario. Deng et al.'s description of inefficiency is related to the formulation of the auction clearing process and hypothesized bid quantities in the auction.

components. We find robust empirical evidence that variation in ARR management strategies helps explain differences between an FTR's auction price and its realized *ex post* value. We use the data to analyze trends in ARR management strategies, noting that 1) ARR management strategies do not change drastically year-over-year, and 2) there is a strong relationship between the physical location of an ARR allocation and its management strategy. That is, for ARR allocations associated with a generating station located in a retail-choice state, the ARR allocation is typically claimed as auction revenue rather than converted into an FTR.

To explain the role of the ARR process in price formation in FTR auctions, we organize the rest of the essay as follows. Section 2 provides a review of the existing literature that examines FTR auction markets. Section 3 provides a conceptual representation of how decisions made in the ARR process influence equilibrium FTR auction outcomes. Sections 4 and 5 describe the data, empirical approach, and results regarding ARR management strategies in the PJM market. Section 6 concludes.

2.2 Related Literature

This essay contributes to the literature that studies the development and performance of markets for financial transmission rights. Hogan (1992) derived what is now known as the simultaneous feasibility conditions, which guarantee revenue adequacy for FTRs issued by the ISO. The simultaneous feasibility conditions are a set of constraints in the auction revenue maximization problem that require the ISO to respect the network's transmission limits when issuing FTRs. In practice, the simultaneous feasibility conditions cannot guarantee revenue adequacy because the ISO must use a static "snapshot" of the network for the FTR auction optimization problem. The actual network configuration used for dispatch (and thus for calculating LMPs) is dynamic, changing due to, for example, unforeseen transmission line outages throughout the period when the FTRs are valid financial obligations. For a comprehensive review of FTR auction theory and mathematical formulations, see Rosellon and Kristiansen (2013).

Recent studies of FTR auctions focus on whether the clearing prices in the auction provide unbiased estimates of future congestion charges. Adamson et al. (2010) examine FTR returns in the New York ISO in the earliest years of FTR auctions and find that transactions profits declined as the market matured. Baltadounis et al. (2017) study FTRs in a capital asset pricing model (CAPM) framework where they test whether specific source/sink pairs experience "abnormal" returns relative to the entire market's returns. Using an *ex post* evaluation of FTR returns in California from 2009-2015, they find that about half of the FTR source/sink pairs studied in California displayed returns statistically different from average market levels (i.e. abnormal returns). The distribution of returns were positively skewed, suggesting that there were more extremely profitable FTR paths than extremely unprofitable paths. Olmstead (2018) studies whether clearing prices in Ontario's FTR auction are unbiased predictors of congestion. Olmstead finds that auction prices are better predictors of congestion when there are more bidders present in the auction. Leslie (2018) conducts a similar study for the NYISO while controlling for the "firm type" of the bidder; that is, he characterizes each auction participant as a generator, an electricity retailer, or a speculator. He also studies whether the fact that an FTR was purchased in a previous round for a given path helps explain the FTR's profitability. Leslie finds that FTRs that clear on paths where there are no open positions are more likely to be profitable and suggests that speculators provide liquidity to the FTR auction market.

Our work is also related to the literature that studies the impact that fundamental supply and demand conditions have on forward market risk premiums. In the context of energy markets, Benth et al. (2008) argue that the timing of hedging decisions made by buyers and sellers, along with their levels of risk aversion, impacts the sign and magnitude of the market risk premium in the forward German electricity market. Botterud et al. (2010) study changes in the sign of the market risk premium in the hydro dominated Nord Pool, where reservoir levels and dam inflow patterns explain some variation in observed risk premiums.

This study is a contribution to the aforementioned literature because of our rigorous accounting for market supply conditions that precede the commencement of FTR auctions. Decisions made during the ARR process determine where on the transmission network cheap supply is available to FTR bidders. More importantly, we conclude that where and how much cheap supply is made available through the ARR process impacts equilibrium auction outcomes, as we demonstrate in the following conceptual model.

2.3 Conceptual Model

In this section, we develop a conceptual model that describes equilibrium outcomes in FTR auctions under various ARR management strategies. To do this, we consider a hypothetical two-node network where “GenCo” sells power to “LSE” across a transmission line. Using this simple network, we demonstrate the impact that the LSE’s ARR configuration decision has on transmission capacity available to FTR bidders in the FTR auction, and ultimately, the impact that the ARR configuration decision has on electricity customers’ expected payoffs due to the LSE’s ARR management strategies.

2.3.1 *Impact of ARR Configuration on the Supply of Transmission Capacity*

The ISO maximizes FTR auction revenue subject to the feasible transmission capacity of the network. In the mathematical formulation of the auction clearing process, transmission capacity is modelled explicitly as the right-hand-side values for each transmission constraint. The majority of the network transmission capacity is allocated to the LSE in the form of ARRs. The LSE determines how much of this transmission capacity is available to bidders at a reservation price of $0 through their ARR management decision not to self-schedule some of their ARR allocation as FTRs. As the LSE self-schedules more ARRs into FTRs, they are removed from the auction and there is less zero-reservation-price transmission capacity available to other bidders. Transmission capacity (i.e. market supply) beyond the ARR allocation is created either by an FTR holder offering to sell a previously acquired FTR or an auction participant bidding to purchase a counterflow FTR (in this case, a counterflow FTR would have the load node as the source and the gen node as the sink).

To demonstrate the effect of an LSE's ARR configuration decision on the supply of transmission capacity, consider a hypothetical ARR allocation on a simple two-node network with one transmission line that has a maximum flow capacity of 100 MW. GenCo owns cheap generation resources located at one node (the "Gen" node) and the LSE's electricity customers are located at the other node (the "Load" node). There is also expensive generation located at the Load node, but expensive generation is only dispatched when the transmission line is at its maximum capacity. Thus, whenever the transmission line is at its maximum capacity and the marginal supplier of power is at the Load node, the ISO collects congestion rent from the LSE that is equal to the opportunity cost of scarce transmission capacity.

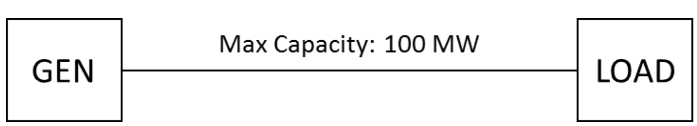

Figure 1. Two Node Transmission Network

Because the LSE's electricity customers pay for the transmission line connecting the Gen node and Load node, the LSE is allocated 100 MW of ARRs as compensation for any congestion rent the ISO collects on the transmission line. The LSE chooses what proportion of this 100 MW ARR allocation to claim as auction revenue and what proportion to convert directly into FTRs. For the sake of our example, suppose the LSE is deciding between the two extrema of the ARR management decision: self-scheduling the entire ARR allocation into FTRs (Scenario 1) or claiming the entire ARR allocation as auction revenue (Scenario 2).

Table 2. Hypothetical 100 MW ARR Allocation between source node "GEN" and sink node "LOAD"

	Self-Scheduled Quantity (MW)	Auction Revenue Quantity (MW)
Scenario 1	100	0
Scenario 2	0	100

Figure 2 demonstrates the impact that the LSE's ARR management decision has on market supply of transmission capacity available to bidders in the FTR auction. In the left frame of Figure 1, the LSE self-schedules its entire ARR allocation into FTRs (Scenario 1). The supply of transmission capacity along the ARR path is composed only of FTR sell offers and counterflow FTR buy bids made by entities other than the LSE (i.e. speculators). Conversely, in the right frame, when the LSE claims their ARRs in the form of auction revenue (Scenario 2), the supply curve includes the 100 MW horizontal portion with price $0 as well as the supply from sell offers and counterflow buy bids. In practice, an LSE may choose a mixed ARR management strategy, e.g. self-scheduling 50% of their ARR allocation into FTRs and claiming 50% as auction revenues.

Figure 2 Supply Curve of Transmission Capacity Available to Auction Bidders between GEN and LOAD, with (Scenario 1) and without (Scenario 2) Self-Scheduled FTRs

Continuing our example, suppose a generator located at the Gen Node has a forward fixed-price contract for power delivery. The structure of a fixed price contract requires both an agreed upon price and location, which in this case is the Load node. However, the generator conducts hourly power transactions with the ISO in the day-ahead market that settle at the Gen node. Thus, the generator has not fully hedged its power sales through the fixed price contract. The fixed price contract guarantees the generator price certainty at the Load node but not at the Gen node; so the generator remains exposed to locational basis risk at the Gen Node whenever the transmission line is at maximum capacity. If the generator were to purchase an FTR with the Gen Node as the source node and the Load node as the sink node, they effectively transfer the location of their fixed price contract from the Load node to the Gen node. This is because the FTR reimburses the generator for their congestion charges between the contract node and the node at which they settle daily power transactions with the ISO.

Suppose the generator bids into the FTR auction a demand schedule for FTRs with Gen node as the source and Load node as the sink. The generator competes for FTRs with other auction participants, including financial speculators, who bid for profitable FTRs. Generators and financial speculators have different objectives in the auction, with generators hoping to hedge locational price risk and speculators hoping to reap the benefits of acquiring an FTR for less than it will pay in congestion rents. It seems reasonable to assume that both generators seeking to hedge and speculators are risk averse, and so at least a portion of the generator's demand curve should exceed the speculators' willingness to pay.[4] Figure 3 presents stylized demand curves for FTRs between the Gen Node and Load Node. The hedging generator's demand curve is the leftmost frame, speculators' demand is the middle frame, and aggregate demand is the right frame.

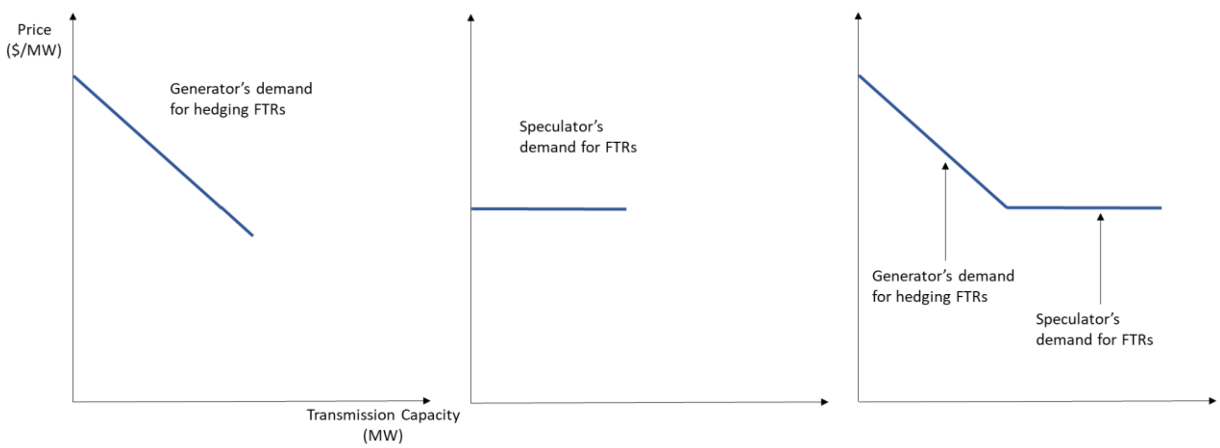

Figure 3. Generator & Speculator Demand for FTRs along the GEN to LOAD path

By *not* self-scheduling ARRs into FTRs (Scenario 2), the LSE makes transmission capacity available at price $0 that can be purchased by the generator and speculators. Figure 4 combines

[4] The generator's inclination to hedge power sales suggests the generator is risk averse, and thus would be willing to pay a risk premium for some quantity of FTRs above the expected value of the FTR to achieve price certainty. Speculators, as profit maximizers, may or may not be risk averse, but would not be willing to pay any price for an FTR above its expected value. If they are risk averse, they would be willing to pay even less for an FTR. Our stylized example assumes that the generator and speculators have symmetric information regarding the expected value of the FTR.

the supply curves from Figure 2 and the aggregate demand curve from Figure 3 to depict the influence that the LSE's self-scheduling decision has on equilibrium prices and quantities for a given ARR/FTR path with fixed hedging and speculation demand. Under Scenario 1 (100% self-scheduling), when the LSE does not make transmission capacity available at \$0, the generator is only able to acquire FTRs by transacting with supply made available by speculators. However, under Scenario 2 (0% self-scheduling), the generator is able to acquire a greater quantity of FTRs at a lower price when the LSE makes transmission capacity available at \$0.

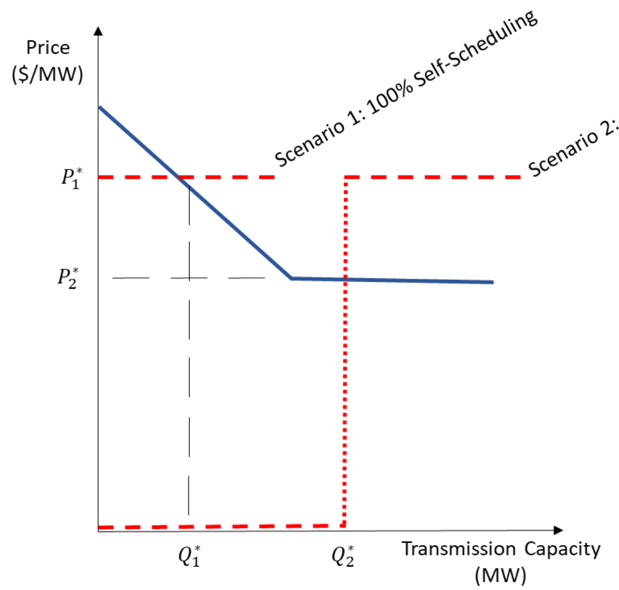

Figure 4. Equilibrium Price and Quantity under Supply Scenarios 1 & 2

Note: Theoretically, transmission capacity is the appropriate unit of analysis for 'quantity' as it relates directly back to the mathematical program that solves the auction problem. Empirically, we do not perfectly observe transmission capacity (either of the system or an individual FTR's impact on transmission capacity) and so have to use FTR quantity (in MW) as a proxy for transmission capacity.

2.3.2 *The Role of Speculators in FTR Auctions*

With risk neutral bidders and no transaction costs, market efficiency implies that the equilibrium auction price of an FTR is equal to its expected *ex post* value (conditional on the information available at the time of the auction). However in this essay and the publications discussed above, we observe that FTRs are persistently profitable for financial speculators, suggesting that financial speculators demand a trading premium for holding FTRs. A portion of the trading premium may be a risk premium if the speculators are not risk neutral. Alternatively, the trading premium may be driven by transactions costs, such as collateral requirements, that are required for auction participants. Further, the cost of developing and executing a trading strategy can also be viewed as a transactions cost. The presence of transactions costs has been studied and identified in other electricity derivative markets (Jha and Wolak, 2018).

When a speculator bids to purchase an FTR, the trading premium *reduces* the speculator's bid price relative to the expected *ex post* value of the FTR. This is regardless of whether the FTR is prevailing flow or counterflow (in expectation). For example, consider an FTR from A→B with an expected *ex post* value of $40. A speculator's hypothetical trading premium might be $5; so the speculator bids $35 for the FTR. Now, consider a speculator placing a bid to buy the counterflow FTR B→A. By definition, this FTR has an expected *ex post* value of -$40. If the speculator's magnitude of trading premium is the same for counterflow FTRs as for prevailing flow FTRs, then the speculator will bid -$45. In both cases, the trading premium is subtracted from the expected *ex post* value of the FTR.

The right frame of Figure 5 depicts the distribution of expected financial surplus in supply Scenario 2 between the hedging generator and financial speculators. The equilibrium auction clearing price is the expected *ex post* value of an FTR between Gen and Load plus the trading premium ("TP") demanded by the marginal bidder (i.e. the speculator) for holding a risky asset. As described above, the trading premium is negative, and thus the equilibrium auction price is less than the FTR's expected value. The hedging generator captures expected financial surplus equal to area B while speculators capture expected financial surplus from area C. This financial surplus is the difference between the revenue the LSE would receive (in expectation) from keeping FTRs themselves and the revenue the LSE receives from the auction by selling the FTRs. Ultimately, this financial transfer is borne by electricity customers who receive credits for ARR auction revenues or FTR revenues on their electricity bills.

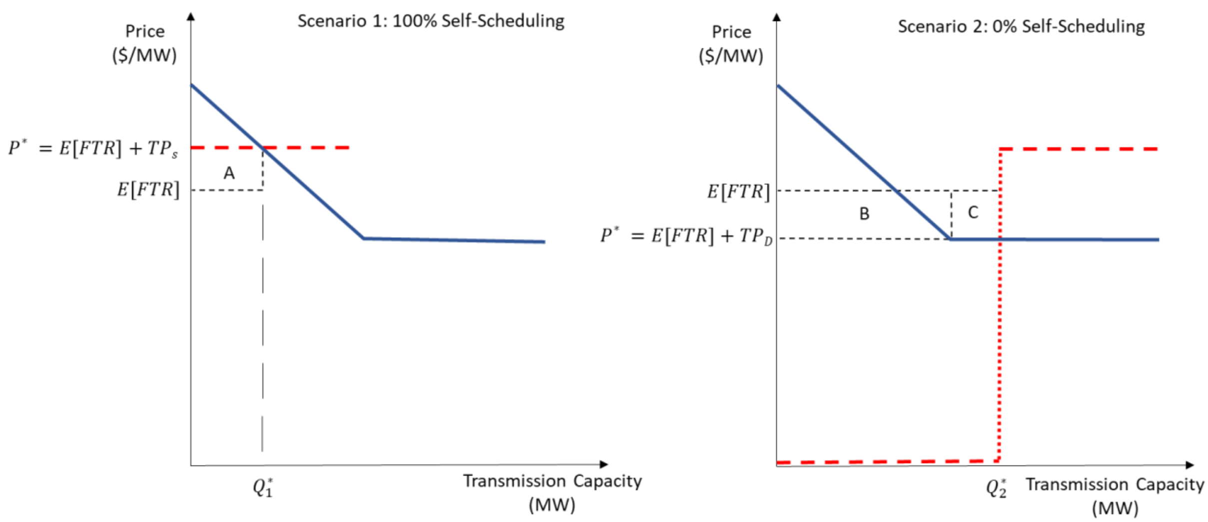

Figure 5 Distribution of Trading Premium Rents in Supply Scenarios 1&2

Note: The equilibrium clearing price in both scenarios is E[FTR] +TP, but TP is positive in scenario 1 and negative in scenario 2. The difference in the sign of TP is driven by whether the financial speculator is the marginal seller (scenario 1), denoted by subscript *s*, or buyer (scenario 2), denoted by subscript *d*.

When the LSE does not make cheap transmission capacity available to bidders by self-scheduling the ARRs into FTRs, the hedging generating firm has to pay a trading premium to speculators offering supply (left frame of Figure 5). Here, the equilibrium auction clearing price is the expected *ex post* value of an FTR between Gen and Load plus the trading premium demanded by the marginal bidder (i.e. the speculator) for *selling* a risky asset; hence, the trading premium is positive. The hedging generator has to pay the speculator's trading premium equal to area A to compensate for the financial participants' risk and transactions costs associated with supplying transmission capacity. This outcome, where the equilibrium auction price exceeds the expected value of the derivative, is typical in insurance markets where the buyer of insurance compensates the seller of insurance for assuming the buyer's risk. Note that the auction clearing price and quantity is irrelevant to the LSE in Scenario 1 because the LSE elected to hold FTRs rather than claim auction revenue.

As we have seen, the equilibrium trading premium can be positive or negative. The size of the trading premium depends on the magnitude of risk aversion and transactions costs incurred by FTR bidders. The sign of the equilibrium trading premium depends on the relative desire of buyers and sellers to hedge. If more buyers hedge (left frame of Figure 5) than sellers, the equilibrium trading premium increases; when the forward price of a derivative is greater than its expected value at maturity, it is often called contango. If more sellers hedge (right frame of Figure 5) than buyers, the equilibrium trading premium decreases and becomes negative; when the forward price of a derivative is less than its expected value at maturity, it is often called backwardation.

2.3.3 *The LSE's Expected Revenue*

Recall from the Introduction that the LSE's payoff function for their ARR allocation can be written as the sum of payouts from ARRs claimed as auction revenue and self-scheduled FTRs, weighted by the configuration chosen by the LSE where $\propto$ corresponds to the fraction of the allocation that is claimed as auction revenue. Because the ARR holder does not know the auction value or FTR value of their ARR allocation at the time they make the configuration decision, both the ARR auction value and the FTR value are random variables. Using our visual aid in Figure 5, we can rewrite the ARR payoff function (equation (4)) and expected payoff function as:

$$\text{Expected ARR Payoff (\$)} \; = \; Q \times \{\propto \times\, (\mathbb{E}[FTR + TP]) + (1-\propto) \times \mathbb{E}[FTR]\} \qquad (2.1)$$

The underlying uncertainty in the FTR Target Allocation is uncertain levels of congestion over the life of the FTR. The underlying uncertainty in the ARR auction revenue, $\mathbb{E}[FTR + TP]$, is the complex interaction of supply and demand bids as well as the market clearing equilibrium trading premium, which could be positive or negative. We demonstrated in our conceptual model that the LSE directly influences this equilibrium auction price through their ARR management decision. Specifically,

$$\frac{\partial \mathbb{E}[TP]}{\partial \propto} \leq 0 \tag{2.2}$$

where an increase in $\propto$ is analogous to shifting the auction market supply curve to the right. In other words, the trading premium is decreasing as we move to the right along the demand curve (note that, in practice, the demand curve is a decreasing step function). In our model, we showed how the trading premium can actually change from positive to negative as $\propto$ increases. For our example, we can write the LSE's expected payoff for each of the two scenarios where the ARR allocation had a quantity of 100 MW as:

$$\text{LSE's Expected Payoff (\$), Scenario 1 } (\propto = 0) = 100 \times \mathbb{E}[FTR] \tag{2.3}$$

$$\text{LSE's Expected Payoff (\$), Scenario 2 } (\propto = 1) = 100 \times (\mathbb{E}[FTR + TP]) \tag{2.4}$$

The sign and magnitude of the trading premium is determined by the marginal bidder in equilibrium. In our depiction of Scenario 2, the trading premium is negative, meaning the equilibrium auction price of the FTR is less than its expected value at maturity. We argue that the presence of FTR bidders' trading premia in conjunction with supply made available through the ARR process explains, at least partially, the observed separation between FTR auction prices and FTR realized values in competitive electricity markets. The following sections investigate the role of ARR management strategies in explaining differences between FTR auction prices and FTR realized values in PJM from 2007-2017.

2.4 Data

All of the data used in this analysis were downloaded from the PJM website under the "markets & operations" tab. PJM removes most market data from its website once it is a few years old; in such cases we retrieved the formerly public data from the PJM website via an internet archive called The Wayback Machine (Internet Archive, 2019). Our data span from 2007-2018. Three of PJM's largest transmission zones (AEP, ComEd and Dominion) joined PJM in 2004-2005, so by the time our analysis begins in 2007, these three transmission zones had been fully integrated into PJM.

The basis of our data is the tables of annual ARR allocations[5] published by PJM. An ARR allocation includes a source node, a sink node, and a quantity (in MW). PJM does not publish the market recipient's name associated with an ARR allocation. The sink node of most ARRs is a load aggregate node, which we classify as the ARR's "region" in our analysis. Most source nodes correspond to a generating station located in PJM. We supplement the ARR allocations with their *Auction Price* in the annual FTR auction, which is calculated as the average value of an FTR along the ARR path across the four rounds of the annual auction; this is consistent with the way PJM compensates ARR holders for their retained ARR allocations. We also include the realized *ex post* value of an FTR along the ARR path, called the *Target Allocation*, which is aggregated from daily files of market results from the day-ahead energy market.

We construct our variable of interest, *Path Capacity*, which is a proxy for how much transmission capacity is available along an ARR path, by taking the difference between the ARR allocation quantity and self-scheduled quantity, in MW, along the ARR path. PJM does not report the quantity of ARRs that are self-scheduled into FTRs along a given path. However, we can infer

[5] We have not yet obtained ARR allocations for market years 2007 and 2008. For these years, we use the 2009 ARR allocations.

self-scheduled quantities from the annual auction results data using the following observations. All self-scheduled FTRs are 24-hour products. The majority of FTRs that clear the auction are either on-peak or off-peak products; hence limiting our search to only 24-hour products substantially decreases the pool of candidate self-scheduled FTRs. Further, the annual FTR auction is conducted in four rounds. PJM makes an equal quantity of "transfer capacity" available in each round. To do this, PJM must clear self-scheduled FTRs in equal quantities across rounds. For example, for a 1 MW self-scheduled FTR from source node A to sink node B, we would observe 0.25 MW clearing from A to B in each round. Furthermore, a self-scheduled FTR is associated with the same participant[6] in all four rounds. For our example, we would observe the same participant clearing 0.25 MW of a 24-hour product from node A to node B in each round. We can then cross-check our candidate self-scheduled FTR observations with the ARR allocations document to confirm that the candidate corresponds to an actual ARR allocation.

Finally, we construct a variable *Hedging Pressure* to approximate how much of the available transmission capacity is demanded by physical asset owners. Our measure of hedging pressure is the FTR quantity, in MW, that clears the annual FTR auction whose source node corresponds to the source node of an ARR allocation. We also require that the purchaser of the FTR be classified as a physical asset owner as defined by PJM (i.e., the member is classified by PJM as a Transmission Owner, Generation Owner, Electric Distributor, or End-use Customer).

2.5 ARR Management Strategies

The conceptual model predicts that, all else equal, claiming an ARR in the form of auction revenue rather than self-scheduling it into an FTR will weakly decrease the equilibrium auction

[6] Participant names are observable in the auction market data, but not the ARR allocation data.

price of the associated FTR. This price decrease is associated with shifting the supply curve of available transmission capacity rightward along the downward sloping demand curve for FTRs. For an LSE, decreasing the auction price of an FTR associated with an ARR allocation is analogous to decreasing revenue received from the ARR allocation. This is problematic for electricity customers because decreased revenue from an ARR allocation means less revenue will be passed through via their electricity bills.

Table 3 PJM-wide Results in the ARR Market (Millions $)Table 3 presents aggregated (i.e. PJM-wide) data of market results. The column "Total ARR Value" measures the total value of all ARRs using annual auction clearing prices (equation 1.3), whereas the column "Total FTR Value" measures the total value of all ARRs using market congestion data (equation 1.2). Note that these two columns ignore whether an ARR was claimed as auction revenue or converted into an FTR. The third column, "Actual Value," accounts for whether an ARR was actually claimed as auction revenue or converted into an FTR. In other words, the third column is the value that was actually recovered by LSEs through their ARR management decisions. In total, LSEs incurred a shortfall of more than $700 million relative to what they would have received if they had self-scheduled all of their ARRs into FTRs. The conceptual model predicts that ARR decision making influences equilibrium auction prices, but not network congestion. Thus, we cannot say that LSEs would have increased their "Actual Value" by claiming more ARRs as auction revenue; the act of claiming more ARRs as auction revenue could decrease the ARR's auction price.

Table 3 PJM-wide Results in the ARR Market (Millions $)

Planning Period	Total ARR Value	Total FTR Value	Actual Value
2007/2008	$ 1,675	$ 1,931	$ 1,771
2008/2009	$ 2,326	$ 1,597	$ 1,723
2009/2010	$ 1,273	$ 765	$ 925
2010/2011	$ 1,012	$ 1,433	$ 1,253
2011/2012	$ 951	$ 718	$ 812
2012/2013	$ 560	$ 605	$ 564
2013/2014	$ 494	$ 1,473	$ 852
2014/2015	$ 721	$ 947	$ 786
2015/2016	$ 931	$ 736	$ 825
2016/2017	$ 902	$ 633	$ 788
2017/2018	$ 552	$ 782	$ 591
Total	$ 11,402	$ 11,624	$ 10,891

The ARR market results displayed in Table 3 conceal important information about the role of ARR management strategies in determining auction equilibria and explaining observed differences between auction prices and realized values. In the next section, we test implications of the conceptual model related to the role of ARR management strategies and hedging pressure on the value of an ARR compared to its realized *ex post* value.

2.5.1 *Empirical Strategy and Results*

Table 4 presents summary statistics for the dependent variable *Target Allocation* and independent variables *Auction Price*, *Path Capacity*, and *Hedging Pressure* included in the regressions. On average, an ARR allocation has an auction value of $4,600 per MW but FTRs associated with ARRs have an average *ex post* value of $4,848 per MW. This average auction markdown of approximately 5% is consistent with the broad literature showing that FTRs sell for a price less than their realized *ex post* value. The average amount of *Path Capacity* (on a per-round basis) associated with an ARR allocation is 13 MW with a standard deviation of 32 MW, suggesting there is substantial variation in the data. The average level of *Hedging Pressure* on an

ARR allocation is less than 50% of the average level of *Path Capacity*, which is consistent with the right frame in Figure 5 of our conceptual model where the supply shift from ARR management decision overwhelms buyers' desire to hedge, thus resulting in an equilibrium auction price below the expected value of the FTR.

Table 4 Summary statistics for the variables included in the ARR management regressions

	Target Allocation	Auction Price	Path Capacity	Hedging Pressure
Units	$/MW	$/MW	MW	MW
Obs	9,618	9,618	9,618	9,618
Mean	$ 4,846	$ 4,600	13	6
St. Dev	$ 17,177	$ 15,997	32	30
Min	$ (350,548)	$ (310,819)	0	0
Max	$ 126,655	$ 143,768	409	738

Our objective is to test whether the quantity of transmission capacity available to bidders in the FTR auction accounts for part of the variation between ARR auction prices and their associated FTR's *ex post* realized values. To do this, we estimate a set of equations of the general form:

$$\begin{aligned} Target\ Allocation_{i,j,k} = {} & \Upsilon AuctionPrice_{i,j,k} + \theta Path\ Capacity_{i,j,k} \\ & + \mu Hedging\ Pressure_{i,j,k} + \boldsymbol{\lambda}_{j,k} + \varepsilon_{i,j,k} \end{aligned} \tag{2.5}$$

Each ARR allocation (our unit of observation) *i* is associated with a region *j* and a year *k*. The vector $\boldsymbol{\lambda_{j,k}}$ captures region-year fixed effects and $\varepsilon_{i,j,k}$ is the error term. Identification of θ, our main coefficient of interest, comes from the fixed effects which capture the impact of unanticipated congestion events that impact all FTRs in a given region and year. Examples of unanticipated congestion events include weather shocks (e.g. "Polar Vortex") or unplanned outages of transmission lines or generators. The main concern with the use of region-year fixed effects is its potentially strong correlation with our variable of interest *Path Capacity*. This concern arises from the fact that, in most regions, *Path Capacity* is quite high or low for all ARR allocations in a given region and year. In short, the region-year fixed effect may capture some of the variation we are interested in, which is the effect of *Path Capacity* on *Target Allocation*. Thus, we also estimate versions of (9) that include year fixed effects rather than region-year fixed effects. We estimate the regressions using OLS with different combinations of fixed effects and higher-order terms. We report the results of four of these regressions in Table 5.

Table 5 Regression results estimating the impact of available transmission capacity on FTR Target Allocation

Dependent Variable: FTR Target Allocation

VARIABLES	(1)	(2)	(3)	(4)
Intercept	872.40***	-527.04***	4,890***	-720.28***
	(162.7)	(52.72)	(1,749)	(153.83)
Auction Price	0.83***	0.87***	0.84***	0.86***
	(0.02)	(0.08)	(0.06)	(0.08)
Path Capacity	17.87***	12.66**	16.63***	45.38*
	(3.31)	(5.56)	(5.31)	(23.80)
Hedging Pressure	-4.53	-3.68	-4.69	-2.93
	(3.60)	(5.19)	(4.96)	(5.23)
Auction Price $\times$ *Path Capacity*				6.81E-04
				(9.63E-04)
Path Capacity^2				-0.38
				(0.23)
Path Capacity^3				7.9E-04
				(5.2E-04)
Year FE	NO	NO	YES	NO
Region-Year FE	NO	YES	NO	YES
N	9,618	9,618	9,618	9,618
Adj. R^2	0.59	0.67	0.61	0.67

*** p<0.01, **p<0.05, *p<0.1
Regression 1 reports Pooled OLS with heteroskedastic-robust standard errors.
The interpretation of the intercept depends on the arbitrarily selected fixed effect suppressed from the regression. Standard errors are clustered at the region-year level

The first regression estimates the relationship using Pooled OLS while regressions two through four use different fixed effects treatments, and regression 4 also uses an interaction between *Auction Price* and *Path Capacity*, as well as squared and cubic terms for *Path Capacity*. In all four regressions, *Path Capacity* is statistically significant, suggesting that the result is invariant to the combination of fixed effects or confounders used in the analysis. *Hedging Pressure* has the sign predicted by the conceptual model, but it is not statistically significant.

An intuitive way to interpret the *Path Capacity* variable is to consider a choice between two FTRs, each along an ARR path, and where each was sold in the annual auction for $100 per MW. The only distinguishing characteristic given regarding the FTRs is how much *Path Capacity* had been available in the auction along each path. Suppose that one of the FTRs was located on an ARR path that had 0 MW of *Path Capacity*, and the other was located on a path that had 100 MW of *Path Capacity*. Which FTR should a profit maximizing investor choose? Our results suggest the investor should choose the FTR along the path that had 100 MW of *Path Capacity* because it has a predicted value (using the results of regression 1) of $1,787 per MW greater than the FTR on the path with 0 MW of *Path Capacity*. The reason for this difference in expected profitability, as suggested by our conceptual model, is that there is a negative trading premium included in the auction price of the FTR sold on the path with 100 MW of *Path Capacity*, but not on the path with 0 MW of *Path Capacity*.

To electricity customers, the financial cost or benefit of the LSE configuring an ARR as auction revenue is the difference between the auction revenue and the realized value of the FTR that would have been passed through to the customer. Figure 6 illustrates the increasing foregone FTR revenue as the LSE claims an increasing quantity of the ARR allocation as auction revenue. Here, moving left to right is analogous to increasing $\propto$ in the conceptual model, where more transmission capacity is being made available to bidders in the auction. We fix the auction price of the FTR at $4,600 per MW, which is the mean of *Auction Price* in our data. Notice at a *Path*

Capacity level of 0 MW, the predicted value of the FTR is less than its auction price. This is consistent with the conceptual model, which shows that when the LSE does not make transmission capacity available through the ARR process, FTR buyers have to pay FTR sellers a trading premium in order to take on the risk of making the FTR available. The FTR buyers' trading premium is decreasing in quantity (i.e. aggregate FTR demand is downward sloping), raising the expected value of the FTR relative to the auction price of the FTR as the quantity of cheap transmission capacity made available by the LSE increases.

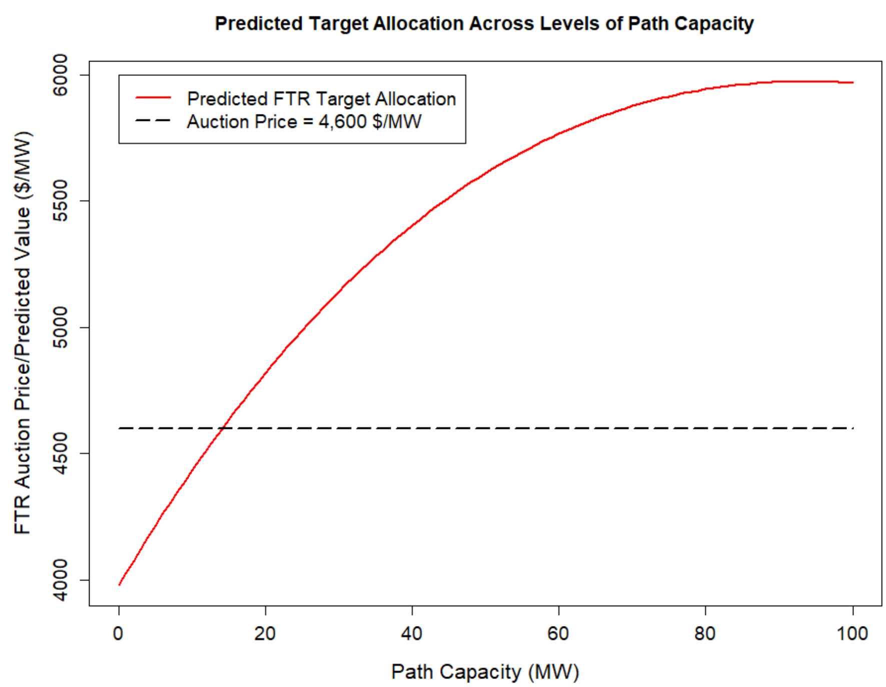

Figure 6 Change in the predicted value of an FTR on an ARR path as transmission capacity increases, holding auction price constant (results from Table 4 regression 4)

2.5.2 *Some Auxiliary Measures*

We consider several regressions as robustness checks on the results reported above. First, we disaggregate our variable of interest *Path Capacity* into two distinct variables, *Total ARR* and *Total Self-Schedule*. Recall that the variable *Path Capacity* is measured by calculating *Total ARR* – *Total Self-Scheduled*. This robustness measure is meant to confirm that an increase in the size of an ARR award (holding self-scheduling constant) increases the expected value of an FTR on the ARR path, and that increasing the quantity of self-scheduled FTRs (holding the quantity of ARRs on the path constant) decreases the expected value of an FTR on the ARR path. Finally, we consider an alternative specification of the model where we introduce a new dependent variable *Profits*. This variable is constructed by simply subtracting *Auction Price* from *Target Allocation*. This setup is consistent with Leslie (2018).

Table 6 reports the results of the robustness checks. In the first two regressions, the two new disaggregated variables have the correct sign as predicted by the conceptual model. *Total Self-Scheduled* can be interpreted as the decrease (in $/MW) in the predicted value of an FTR as the quantity of ARRs self-scheduled into FTRs increases. *Total ARR* can be interpreted as the increase in the predicted value (in $/MW) of an FTR on an ARR path when the available transmission capacity on the path increases. Using the Wald test, we cannot reject the hypothesis that the coefficient on *Total ARR* is equal to the negative of the one on *Total Self-Scheduled*.

Table 6 Results of Alternative Specifications

	Dependent Variable: FTR Target Allocation		Dependent Variable: Profit	
VARIABLES	(1)	(2)	(3)	(4)
Intercept	-515.9***	4,857***	-460.33***	3,271***
	(56.6)	(1,754)	(45.39)	(1,451)
Auction Price	0.87***	0.84***		
	(0.07)	(0.06)		
Path Capacity			7.80	12.85**
			(5.46)	(5.37)
Hedging Pressure			-7.49	-9.17*
			(5.57)	(5.39)
Total ARR	10.89*	14.67**		
	(5.84)	(5.85)		
Total Self-Scheduled	-8.03	-12.51		
	(6.60)	(8.00)		
Year FE	NO	YES	NO	YES
Region-Year FE	YES	NO	YES	NO
N	9,618	9,618	9,618	9,618
Adj. R^2	0.66	0.61	0.20	0.06

*** p<0.01, **p<0.05, *p<0.1

All standard errors are clustered at the region-year level.

One limitation to our analysis is the extent to which *Path Capacity* does not perfectly measure transmission capacity along an ARR path. As described earlier, electricity travels according to the path of least resistance creating the phenomenon of loop flows. Our measure of *Path Capacity* does not capture the impact of loop flows. That is, the self-scheduling decision along an ARR path will impact the available of transmission capacity along a neighboring ARR path, yet it is impossible to say how impactful loop flows are for a given ARR path because we do not have access to the network parameters. We hope to have partially alleviated this concern by clustering our standard errors at the region-year level because standard errors may be correlated at the region-year level due to loop flows (Cameron and Miller, 2014).

We consider two additional checks for mismeasurement of *Path Capacity*. First, we aggregate the data to the region level and estimate Pooled OLS again using the aggregated data. Second, we construct a new variable that measures, for a given ARR allocation, how much transmission capacity exists in its region apart from its own transmission capacity. We then re-estimate regression 2 in Table 5 while including this new variable that controls for excess transmission capacity in a region. In each of these scenarios, the coefficient on *Path Capacity* remains positive and statistically significant.

2.5.3 *Patterns in ARR Management Strategies*

There are two notable patterns in ARR management strategies across space and time in PJM. First, the proportion of self-scheduled FTRs has been declining over time. At the start of our data, approximately 70% of ARRs were converted directly into FTRs. More recently, only about 30% of ARRs are being converted directly into FTRs. Figure 7 shows the time trend of decreasing percentage of self-scheduled FTRs over the past 10 years.

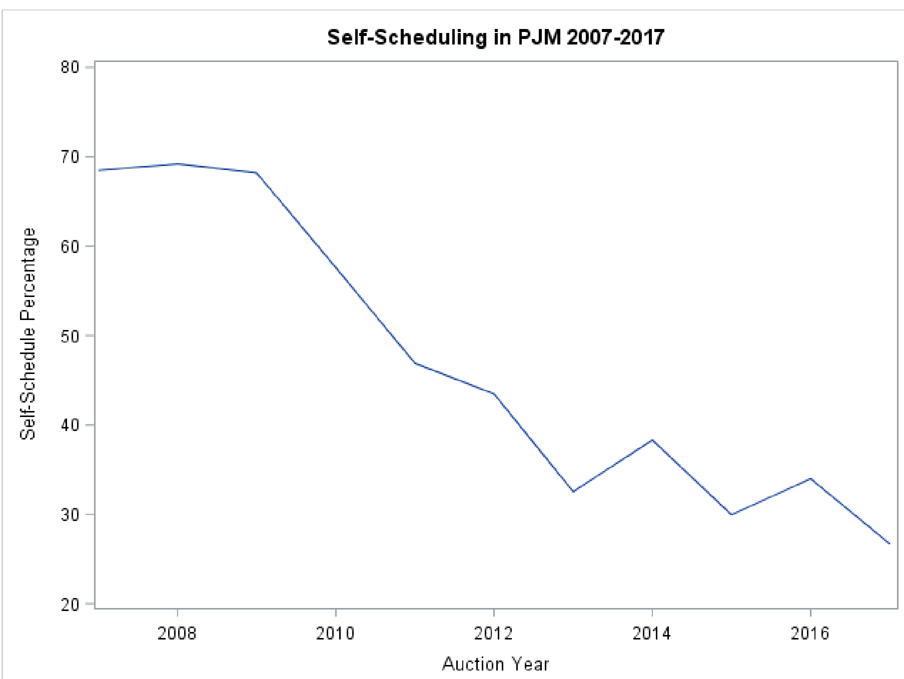

Figure 7 Proportion of ARRs Self-Scheduled as FTRs in PJM

Second, ARR management strategies can vary greatly across zones, but the management strategies within a zone is fairly persistent. Figure 8 demonstrates the regional variation in ARR management strategies across four of the largest transmission zones (by MW) in PJM for our entire sample period. We see that there is not an absolute strategy in these regions (i.e. no 100% self-scheduling or 100% auction revenue), but the three largest zones have a relatively dominant strategy. Self-scheduled proportions in AEP and Dominion are very high relative to ComEd, whereas PECO is closer to evenly split.

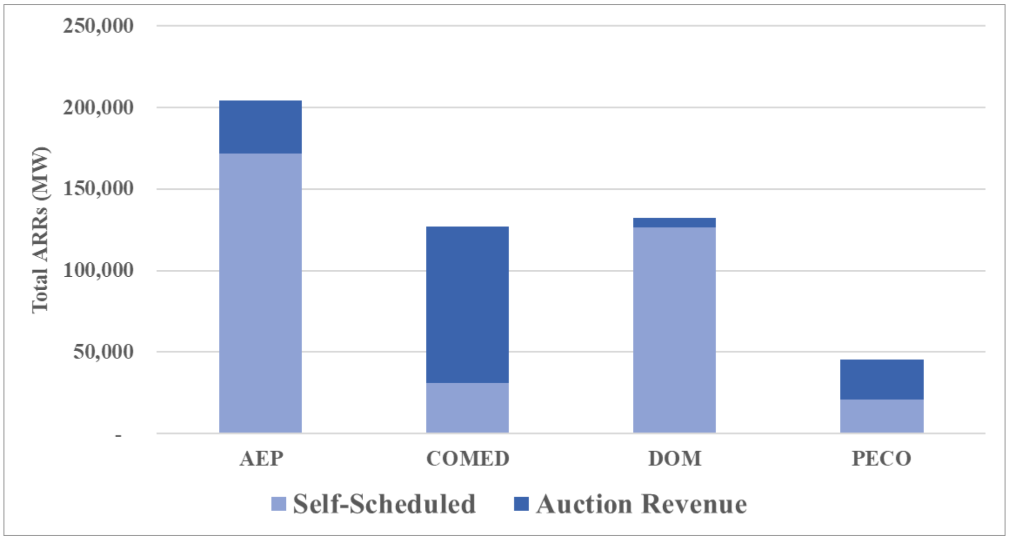

Figure 8 ARR Management Strategies in Selected Transmission Zones, 2007-2018

To study the yearly changes in ARR management strategies, we consider a simple model of the form:

$$Self\ Scheduled_{i,j,t} = \ \Upsilon Self\ Scheduled_{i,j,t-1} + \theta Profit_{i,j,t-1} + \varepsilon_{i,j,k} \qquad (2.6)$$

where the dependent variable *Self Scheduled* is the quantity (in MW) of self-scheduled FTRs for a given ARR allocation. *Self Scheduled* is regressed on its own lagged value and its own lagged *Profit*, which is calculated as the difference between last year's FTR Target Allocation and last year's Auction Price. The logic is that if, for a given ARR allocation, last year's Target Allocation was high relative to its Auction Price, then we might expect an increase of self-scheduled FTRs for that path. We also consider the impact of a path's lagged auction price. The results of these regressions are found in Table 7.

Table 7 Results of Regressions Predicting Levels of Self-Scheduled FTRs

Dependent Variable: Self-Scheduled FTRs (MW)

VARIABLES	(1)	(2)	(3)
Intercept	3.13**	3.06**	-0.56***
	(1.24)	(1.48)	(0.10)
Lagged Self-Scheduled FTR	0.84***	0.84***	0.82***
	(0.04)	(0.05)	(0.04)
Lagged Profit	1.36E-04	1.32E-04	
	(8.3E-05)	(9.9E-05)	
Lagged Auction Price			4.0E-05
			(4.8E-05)
Year FE	NO	YES	NO
Region-Year FE	YES	NO	YES
N	7,499	7,499	7,499
Adj. R^2	0.81	0.81	0.83

*** p<0.01, **p<0.05, *p<0.1

All standard errors are clustered at the region-year level

The regression results indicate that the best predictor of a given year's self scheduled FTR quantity for an ARR path is last year's self-scheduled FTR quantity. The coefficient on lagged profit is numerically very small and statistically insignificant at the 10% level, suggesting that LSEs do not change their ARR management strategies in response to the previous year's FTR profitability. Likewise, last year's auction price was a poor predictor for the following year's ARR management strategies.

A final consideration to understanding ARR management strategies is whether there is any qualitative connection between the industrial organization of the electricity industry in the state where an LSE is located and the ARR management strategy employed by the LSE. Notably, almost all ARRs are self-scheduled into FTRs in the Dominion transmission zone of PJM. The Dominion transmission zone is primarily located in Virginia, which is one of the few states in PJM that does not offer competitive retail supply for residential electricity customers. In this case, it makes sense for a vertically integrated utility to self-schedule their ARRs into FTRs because they are responsible for managing both generation costs and electricity customer rates, and an FTR between the two ensures price certainty between the two entities. Table 8 summarizes the percentage of ARRs self-scheduled into FTRs by state for the 2017/2018 planning period, and indicates whether that state is a retail choice state.

Table 8 Percentage of ARRs Self-Scheduled into FTRs by state of ARR source node, 2017/2018 planning period

State	Total ARRs (MW)	Percent Self-Scheduled	Retail Choice State
North Carolina	665	95%	No
Virginia	10,171	90%	No
West Virginia	8,688	56%	No
Michigan	1,338	50%	Yes
Indiana	3,341	44%	No
Kentucky	1,435	39%	No
Ohio	11,721	23%	Yes
Illinois	11,008	11%	Yes
Maryland	5,764	3%	Yes
Pennsylvania	16,997	2%	Yes
Delaware	1,336	2%	Yes
New Jersey	7,341	0%	Yes
Washington, D.C.	297	0%	Yes

Notes: ARR source nodes are mapped to states using data from PJM, while retail choice state information comes from Zhou (2017).

The ARR management strategies employed by LSEs appear to be persistent (i.e. they do not change drastically year-over-year) and appear to be linked to state-level market regulation. For ARR allocations whose source node is located in a retail choice state, the predominant strategy is to claim the auction revenue from an ARR rather than self-schedule it into an FTR. This observation could be related to the decoupling of generation from load in most retail choice states, which decreases an ARR's effectiveness as a hedging mechanism.

2.5.4 *Discussion*

We find empirical evidence that the quantity of transmission capacity available to FTR bidders on an ARR path is a determinant of FTR profitability, and correspondingly, is a determinant of electricity customers' expected revenue. This finding is robust to numerous specifications. This result is critical because LSEs decide how much transmission capacity is available through the ARR process, which determines how much auction revenue electricity ratepayers will receive. The results also suggest that when the LSE does not make transmission capacity available in the auction, the auction price of an FTR *exceeds* the expected value of the FTR. This is consistent with both our conceptual model and the normal functioning of markets that include deterministic prices for uncertain payoff streams such as insurance markets.

2.6 Conclusion

Regulators are increasingly concerned about the effectiveness of FTR auctions to reimburse electricity customers for their congestion charges. We hypothesize that FTR bidders demand a trading premium to compensate for taking on risky returns and/or transaction costs, and that on the margin this trading premium creates a separation between an FTR's price at auction and its expected *ex post* value. In many competitive electricity markets, FTR auction revenues are returned to electricity customers through a process of Auction Revenue Rights where the value of an ARR is determined in an FTR auction. We show that the ARR management strategies employed by LSEs have a consistent first-order effect on the value of an ARR. Specifically, when an ARR holder increases the quantity of transmission capacity available to bidders in the auction (rather than directly converting the ARR into an FTR), the ARR holder effectively shifts the transmission capacity supply curve to the right. This decreases the value of the associated ARR. Electricity customers suffer financially when ARR values decrease because there is less revenue passed through onto their electricity bills.

One of the objectives behind the ARR process is to provide LSEs with a hedge against congestion risk. Another concern related to this study is the LSE's exposure to congestion risk depending on whether they claim ARRs as auction revenue or convert them into FTRs. In theory, if the LSE converts all of their ARRs into FTRs, then their net expected return on congestion expenditures plus FTR revenue is mean zero with zero variance; that is, the LSE's FTR portfolio perfectly offsets congestion payments.[7] When the LSE claims their ARRs as auction revenue, the LSE remains exposed to risky congestion charges in the day-ahead energy market. In PJM, approximately 70% of ARRs are claimed as auction revenue, suggesting that electricity customers may be exposed to the bulk of uncertain congestion events that occur in the energy market.

The magnitude of the trading premium associated with ARRs could be partially mitigated by changing both the ARR product structure and the auction in which ARRs are sold. Currently (in PJM), ARRs are full year products that have to be claimed as auction revenue or self-scheduled into FTRs during the annual FTR auction. A full-year ARR could be disaggregated into seasonal ARRs that are sold, or self-scheduled, during the monthly FTR auctions. The benefits of this change would be twofold: 1) the products would be shorter term and market conditions would be more well-known in the monthly auctions than during the annual auction, which should shrink the trading premium demanded at the margin; and 2) LSEs would be able to self-schedule FTRs or

[7] Bosquez Foti (2016) notes that PJM's ARR allocation process is not as well-suited for providing economic hedges relative to the allocation process and market structure of other ISO/RTOs. That is, the ARRs that are allocated cannot provide a perfect hedge, even if they are all self-scheduled into FTRs.

claim auction revenue based on their seasonal risk preferences, rather than having to make the decision for a full year.

This essay focuses on competitive electricity markets that use an ARR process, but the conceptual framework also applies to markets that have do not have this mechanism. Most, or even all, ISO/RTOs auction off some amount of “excess capacity” (including PJM) that is neither allocated to LSEs in the form of ARRs nor directly allocated to LSEs in the form of FTRs. By default, this excess capacity is marketed in FTR auctions with a reservation price of $0; hence, the supply curve used in these markets is analogous to that in the right frame of Figure 5. To our knowledge, all empirical studies confirm that FTRs in regions without an ARR process are on average sold for prices below their *ex post* value, which is consistent with our conceptual model.

CHAPTER 3. POTENTIAL CROSS-SUBSIDIZATION IN PJM'S ARR/FTR MECHANISM

3.1 Introduction

As states transition away from state-regulated, vertically-integrated electric utilities toward a competitive market model, the incumbent electric utility is usually required to divest part of their business assets (e.g. generation, transmission/distribution, retail services) to eliminate their vertical monopoly. These assets are sometimes sold to a third party that is unaffiliated with the incumbent utility. In other cases, some of the assets are sold to a company affiliated with the incumbent utility, i.e. sold to a subsidiary of the same corporation that owns the incumbent utility. In such cases, the legally separate subsidiaries must conduct themselves in the market like any other competitors ought to—they cannot engage in anti-competitive behavior such as collusion or exclusive dealing. The subsidiary of the utility that owns the transmission and distribution network remains regulated because that subsidiary retains a monopoly over the physical shipment of power in the area. Other sectors of the electricity industry, such as generation and retail supply, are deregulated and opened up to competition from unaffiliated companies.

In this essay, we study a transaction that often occurs between affiliates of the same investor-owned utility (IOU), which is a corporation that owns regulated and deregulated subsidiaries. The transaction we study is the purchase and sale of a financial derivative called a Financial Transmission Right (FTR). An FTR is effectively a financial swap where an FTR buyer is paying a fixed amount of money for a future stream of uncertain cash flows. Consumers of power (called load-serving entities or LSEs) have the option to sell FTRs in an auction conducted by the RTO/ISO and collect the revenue associated with the sale of FTRs. Alternatively, the LSE has the option to retain the FTR for themselves, meaning they retain the right to the future stream of uncertain cash flows. LSEs exercise this hold/sell option through a mechanism called the Auction Revenue Right (ARR) process, where an ARR corresponds to a one MW claim to auction revenue or a one MW FTR depending on the choice made by the LSE.

We begin by presenting a conceptual discussion showing that an IOU's profit-maximizing strategy is for its LSE to manage ARRs in such a way that improves their unregulated subsidiaries' ability to acquire cost-effective FTRs. The regulated LSE receives ARRs to offset congestion rents paid by the LSE, but the IOU also owns unregulated subsidiaries that purchase FTRs to hedge their exposure to locational basis risk in the spot energy market (Figure 9). Ostensibly, this IOU has competing interests in the FTR auction. On one hand, the regulated LSE's customers are the recipients of the value of their ARRs, so increasing the value of ARRs increases the amount of money passed through to the retail customers. On the other hand, the IOU wants their unregulated subsidiary to purchase FTRs at the lowest price possible to increase the returns to the corporation. In other words, the regulated LSE simply passes through the benefits (or costs) associated with its ARR allocation to its electricity customers without providing a financial benefit to the IOU, whereas the IOU can profit from cheaply acquired FTRs and simply pass the congestion costs through to customers. Therefore, the strategy of claiming the revenues from the auction via the ARR rather than self-scheduling it as an FTR provides a tangible benefit for the IOU but may decrease the amount of money passed through to electricity customers in the process. Financial speculators require a risk premium for holding a risky asset, meaning FTR auction clearing prices are (in expectation) lower than the expected cash flows generated by the FTR. Thus, when the LSE sells FTRs to the unregulated entity, there is a financial transfer in expectation from the regulated LSE to the unregulated entity.

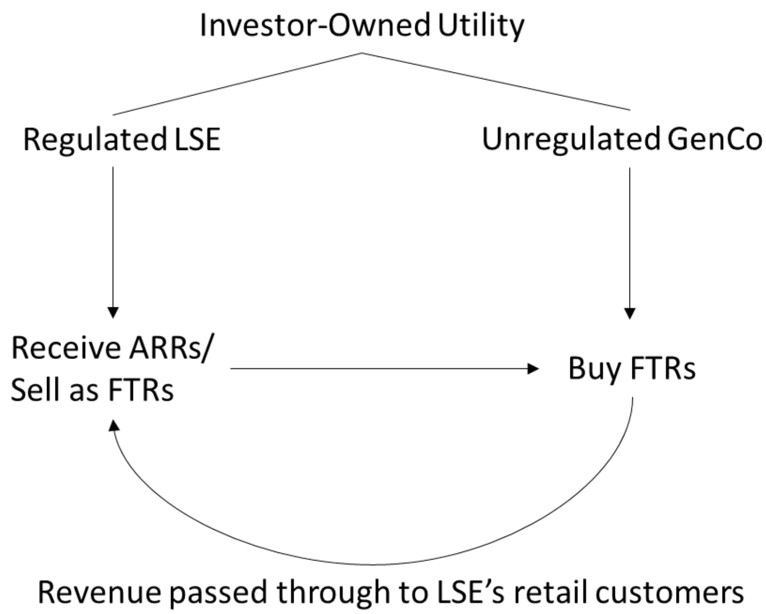

Figure 9 Interaction of an IOU's Regulated and Unregulated Subsidiaries in FTR Auctions

Any type of entity can participate in FTR auctions, including entities that have a physical stake in the electricity industry as well as financial speculators who simply trade FTRs with the intent of earning profits. There is a large literature (e.g. Olmstead, 2018; Leslie, 2018) showing that the auction prices of FTRs are systematically lower than the expected future stream of cash flows that FTRs produce, and most of these profits are captured by financial speculators. Leslie (2018) suggests the difference between an FTR's auction price and *ex post* value is best explained by a trading premium demanded by financial speculators in order to convince them to operate in the market. In theory, competition between financial speculators should benefit the market by providing price discovery and mediating any potential exercise of market power in the auction. However, financial speculators cannot carry out some functions. For example, financial speculators cannot ensure that a regulated participant will behave in the best interest of its electricity customers and not in the best interest of the LSE's IOU.

We document a setting where an IOU owns a regulated utility as one subsidiary and also owns baseload generating stations held in a separate subsidiary. These subsidiaries operate in the same transmission zone in the PJM Interconnection, which is the largest RTO by installed generating capacity in the United States. Indeed, the observational evidence is consistent with the strategy outlined in our conceptual model, where the generating stations purchase cost-effective FTRs that appear to be offered into the auction by the regulated utility. Effectively, the regulated subsidiary is cross-subsidizing the unregulated utility's hedging needs by offering desirable financial derivatives for sale at a $0 reservation price. Financial speculators also may earn substantial trading profits in the region because they also purchase some of the transmission capacity made available through the ARR process. However, the fact that financial speculators require a premium to compensate for the risk or transactions costs inherent in the FTR purchase, means that the market clearing price will be below the expected value of the FTR payouts on average.

This essay proceeds as follows. We begin with a brief description of how the ARR process works in PJM, with a focus on what types of entities receive ARRs. We then provide a conceptual discussion of an IOU's profit-maximizing strategy when they own regulated and unregulated entities in the same zone. Next, we discuss the market structure of the Commonwealth Edison (ComEd) transmission zone in PJM, where Exelon Corporation owns the regulated utility ComEd as well as many nuclear power plants held in a separate subsidiary called Exelon Generation. We explore FTR auction strategies and outcomes for both ComEd and Exelon Generation. Finally, we conclude.

3.2 The ARR Process in PJM

PJM allocates ARRs to LSEs prior to the commencement of a planning period's annual FTR auction. Each ARR in the LSE's complete allocation consists of a source/sink combination and quantity (in MW). The LSE has the option to "self-schedule" any fraction of each ARR allocation into an FTR, claiming the FTR's revenue stream in the future. The fraction of any ARR that the LSE does not self-schedule into an FTR is automatically marketed for sale in the annual FTR auction with no reservation price.

The source nodes of an ARR allocation tend to correspond to generating stations in the LSE's service territory, and the sink node is typically the aggregate load node in the LSE's territory. The rationale for this allocation scheme is that if the LSE self-schedules their entire ARR allocation into FTRs, then their portfolio of FTRs will completely offset their actual congestion payments in the day-ahead energy market between generating stations and their aggregate load node. Further, if the ARR allocation mimics contracted energy purchases, then the self-scheduled ARRs will provide a perfect hedge against uncertain congestion payments up to the contracted quantity (in MW).

To receive ARRs, an LSE needs to prove that they do in fact serve load. In PJM, priority in the ARR allocation process favors entities that schedule firm (i.e. uninterruptible) transmission service for the upcoming planning period. By scheduling firm transmission service, the LSE is permitted to charge their customers a transmission service charge that has been approved by the state utility commission and FERC to recover the fixed costs of operating, maintaining and upgrading the transmission and distribution network in the service territory. Because the LSE passes the cost of transmission service through to their customers, the LSE and its customers have property rights over the transmission network, including property rights to the congestion rent that is collected due to scarce transmission capacity. Thus, ARRs are provided to LSEs to help them recover the congestion rent they will pay in the spot energy market.

3.2.1 *Types of Load-Serving Entities*

The term "load-serving entity" is vague and simply defining the term has been the subject of a drawn-out political process.[8] FERC defines an LSE as "any entity, including a load aggregator or power marketer, that serves end-users within a control area and has been granted the authority or has an obligation pursuant to state or local law, regulation, or franchise to sell electric energy to end-users located within the control area" (FERC, 2016).

Several different types of entities meet FERC's definition of an LSE, such as regulated utilities (e.g. Commonwealth Edison) and unregulated utilities (e.g. competitive retail suppliers). The distinction between regulated and unregulated entities is useful because regulated utilities are obligated to pass through ARR revenues to their retail customers via their electricity bills, while unregulated entities have no such obligation. Moreover, whether an LSE is regulated or unregulated impacts an LSE's incentive to maximize ARR revenue on behalf of its electricity customers.

Regulated utilities often own the local distribution network (and possibly the surrounding transmission system) and are overseen by state utility commissions. In many states, the regulated utility also provides retail electric service, sometimes called "default service," to customers who have not switched to a competitive retail supplier. For regulated utilities, the revenues from ARRs can be passed through to customers in different ways, such as a credit on the cost of procuring electricity or a credit on the cost of transmission services. In any case, the bulk of ARR revenues

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[8] See California ISO's effort to redefine, and final definition of, load serving entity here: http://www.caiso.com/informed/Pages/StakeholderProcesses/CompletedClosedStakeholderInitiatives/LoadServingEntityDefinitionRefinement.aspx

collected by a regulated utility are transferred directly to their retail electricity customers via their electricity bills.

Unregulated LSEs are profit maximizers who, it seems, are not required by law or regulation to directly pass through ARR revenues to their electricity customers. Rather, the profit motive creates the incentive for unregulated LSEs to maximize ARR/FTR revenues, and competition among regulated and unregulated LSEs creates the incentive to completely pass through ARR/FTR revenues to electricity customers. If the retail service market is perfectly competitive, then unregulated LSEs will seek to maximize ARR/FTR revenues to pass through to their customers. If the retail service market is not perfectly competitive, then an unregulated LSE may be able to capture some ARR/FTR rents for themselves. Note that unregulated LSEs must still pay for access to the transmission and distribution network and are charged the same rate for this access as customers of the regulated LSE. However, this fixed charge is separate from any congestion-related costs including ARR and FTR revenues.

3.3 An Investor-Owned Utility's Profit Maximizing Strategy

In this section, we describe how legally separate subsidiaries of an investor-owned utility interact in auctions for FTRs. Recall that an LSE receives ARRs which they can either self-schedule into FTRs (i.e. keep the FTRs for themselves) or allow those same FTRs to be sold in the annual FTR auction and claim the revenue from the FTRs' sale. Thus, the LSE can have a substantial impact on FTR supply in the auction, depending on the decision they make with their ARRs.

Consider an example where GenCo and LSE are two subsidiaries of an IOU. The subsidiary LSE owns and operates the transmission and distribution system that encompasses the territory served by GenCo. LSE also provides retail electric service to customers in its service territory who do not elect to purchase electricity from a competitive retailer. LSE and GenCo participate in a competitive electricity market called ISO. Because LSE has a natural monopoly over transmission and distribution of power in this territory, it is a regulated utility. That is, its business costs are passed through to its electricity ratepayers at government-approved rates including a markup. The subsidiary GenCo is an unregulated, profit-maximizing participant in the ISO market. Competitive generators have equal access to the transmission system owned by LSE.

Suppose GenCo has forward contracts for power delivery that settle at a pricing hub composed of nodes in the LSE territory. Because GenCo settles daily power transactions with the ISO at each of its stations' individual nodes, GenCo is exposed to locational basis risk between each of its generators' nodes and the pricing hub. As a risk averse agent, GenCo seeks to hedge its locational basis risk by purchasing FTRs whose source node is its generators' nodes and where the sink node is the pricing hub in the LSE's territory.

To understand the IOU's profit maximizing strategy, it is important to make a distinction within the IOU's constituency, namely between the LSE's electricity customers and the IOU's shareholders. The LSE's electricity customers are not concerned with the IOU's profitability per se, but rather rely on the LSE's ability to deliver power at the least cost while entrusting the LSE with delivery-related services (e.g. reliability).The LSE's electricity customers have the option to switch to a competitive retail electric supplier, but have not switched for a variety of reasons such as search-related costs or the possibility that the LSE actually charges less for electricity than competitive retailers, as was the case in Illinois in 2017 (Illinois Commerce Commission, 2018). The LSE's electricity customers expect the LSE to behave in a way that is in the best interest of the electricity customers.

The IOU's shareholders, on the other hand, depend on the IOU to be profitable. In our setting, the IOU has no incentive to maximize the value of the LSE's ARR allocation because revenue (or lack thereof) earned in the ARR process is passed through to the LSE's electricity customers. In other words, the IOU's shareholders do not directly benefit from maximizing the value of ARRs. Furthermore, it is reasonable to assume that the impact of a non-revenue-maximizing ARR strategy will go unnoticed by individual electricity customers because it is a small, but not negligible, credit on their electricity bill. The IOU has an incentive to undertake an ARR management strategy that benefits GenCo, the unregulated subsidiary of the IOU, whose profitability and competitiveness is affected by its ability to hedge its market activities.

A generating station's ability to purchase FTRs for hedging is greatly aided by the LSE *not self-scheduling* FTRs, as visualized by Figure 10. In this setting, FTR supply is made available by either the LSE not self-scheduling FTRs (meaning they are for sale in the auction) or financial speculators offering supply. The downward sloping portion of demand is GenCo's demand, while the horizontal portion of demand is demand from financial speculators. In the leftmost frame, the LSE has self-scheduled their entire ARR allocation in to FTRs, meaning the LSE has made no FTR supply available. In the middle frame, the LSE has self-scheduled only half of their ARR allocation, meaning they are supplying some FTRs at a reservation price of $0 to FTR auction bidders. Notice that the equilibrium auction price is lower than the price in the leftmost frame because the LSE has effectively shifted the FTR supply curve to the right. Finally, in the rightmost frame, the LSE has not self-scheduled any FTRs, meaning all of those FTRs are available to FTR auction bidders. In this case, GenCo receives the highest quantity of FTRs of the three cases and at the lowest equilibrium price. So, for a profit maximizing IOU that owns an unregulated entity that operates in the same territory where it owns a regulated LSE, we would expect to see low levels of self-scheduled FTRs by the LSE if the unregulated entity wishes to purchase FTRs for hedging purposes.

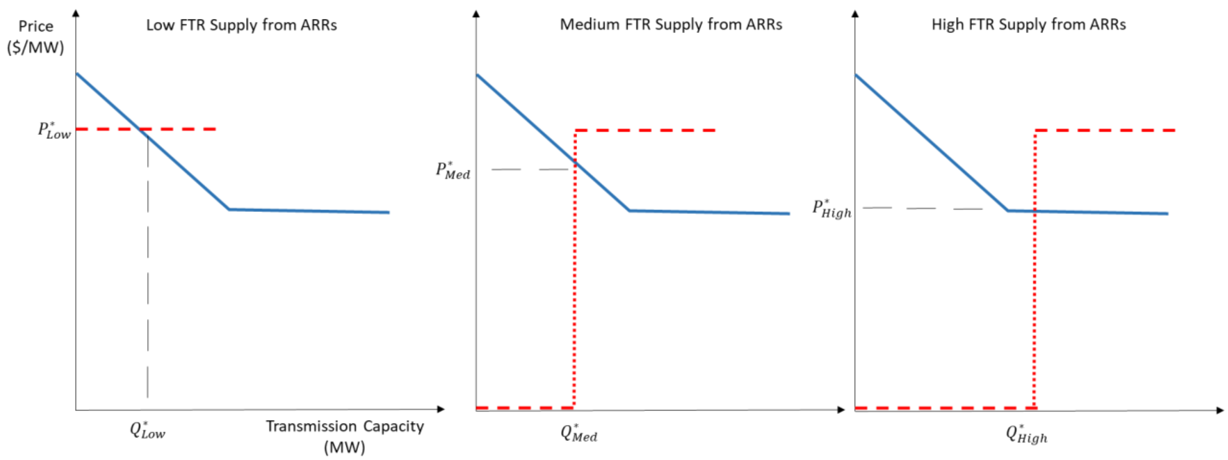

Figure 10 Hypothetical Equilibrium FTR Auction Price and Quantities Given Low, Medium, and High Levels of FTR Supply from the ARR Process

Note: Low FTR supply from ARRs means the LSE has self-scheduled all of their ARR allocation into FTRs, meaning they are not supplying FTRs into the auction. Conversely, high FTR supply from ARRs means the LSE has elected to claim auction revenue from the sale of their entire ARR allocation, meaning they are supplying FTRs into the auction.

In the following section, we conduct a descriptive and empirical analysis of the Commonwealth Edison (ComEd) region of PJM. This zone is a useful case study because the investor-owned utility, Exelon, owns the regulated utility ComEd as well as several nuclear power plants that serve the ComEd region under a separate subsidiary, Exelon Generation.

3.4 The ComEd Transmission Zone

The ComEd transmission zone encompasses the Chicago metro area and northern Illinois. ComEd owns over 5,000 miles of high voltage transmission lines covering a service territory of 11,400 square miles (Exelon Corporation, 2018). In 1997, the Illinois General Assembly passed the “Customer Choice Act” as a means of restructuring the electricity industry in Illinois. Under restructuring, ComEd was forced to sell its fossil-fueled power plants but was allowed to transfer its nuclear fleet to a separate subsidiary held by Exelon (ComEd's parent corporation) called Exelon Generation. ComEd, the largest electric utility in Illinois, joined the PJM Interconnection in 2004.

3.4.1 *ComEd Market Structure*

Table 9 provides annual statistics for the ComEd zone's hourly metered load. Aggregating hourly electricity demand data into annual summary statistics obscures the fact that electricity demand varies greatly by hour of the day, day of the week, and season. However, we present these aggregate statistics to get a sense of baseload demand and any major trends in electricity load in the region. From 2013 to 2017, average and minimum metered load were relatively stable in the region. Maximum metered load exhibits high year-to-year variation from 2013 to 2014 but then also stabilizes.

Table 9 ComEd Transmission Zone Hourly Metered Load (MWh)

Year	Average	Min	Max	St. Dev
2013	11,549	7,394	22,269	2,241
2014	11,441	7,237	19,721	2,035
2015	11,179	7,376	20,162	2,116
2016	11,426	7,290	21,175	2,433
2017	11,043	7,227	20,351	2,102

Source: Adapted from PJM (2013-2017)

Table 10 lists the generating stations owned by Exelon Generation that are located in the ComEd transmission zone. All five of these stations are nuclear power plants. Because it is costly to change the output level of nuclear plants often or operate them too far below their maximum capacity, these five plants have capacity factors greater than 94%, meaning they are running near full capacity for most of the year. This is important in our study because the FTRs that are sold in PJM's annual FTR auction are full-year products that cover either all on-peak or off-peak hours.

Thus, FTRs sold in the annual auction are best suited for hedging generating units that are expected to run throughout the day and year.

Table 10 Generating Stations owned by Exelon Generation in the ComEd Zone

Name of Station	Nameplate Capacity (MW)	Capacity Factor[a]
Braidwood Generating Station	2,354	96%
Byron Generating Station	2,300	97%
Dresden Generating Station	1,773	99%
LaSalle County Generating Station	2,234	97%
Quad Cities Generating Station	1,880	94%
Total	10,541	

Source: Adapted from EIA's annual electricity generation data (2017)

[a] Calculated using plant-level Net Generation in 2016

Table 11 lists major generating stations in the ComEd zone that are not owned by Exelon. To the authors' knowledge, these are the largest non-Exelon units in ComEd. The capacity factors for these competitor units are substantially lower than Exelon's nuclear units. Thus, for most of these units, a hedging strategy may not include FTRs purchased in the annual FTR auction because the unit is not expected to produce power throughout the year. For example, some of these units may produce less power during the shoulder months (e.g. April, September) when electricity demand is lowest. For these units, FTRs can be purchased in the monthly auctions to better align with the months when these units generate consistent output.

Table 11 Major Generating Stations not Owned by Exelon in the ComEd Transmission Zone

Name of Station	Owner	Fuel Type	Capacity (MW)	Capacity Factor
Elwood Energy	Elwood Energy	Natural Gas	1350	10%
Joliet Station	NRG	Natural Gas	1326	58%
Kendall Facility	Dynegy	Natural Gas	1288	64%
Kincaid Station	Dynegy	Coal	1108	44%
Powerton Station	Midwest Gen	Coal	1538	34%
Waukegan Station	NRG	Coal/Oil	790	25%
Will County Station	NRG	Coal	510	47%

Source: Adapted from EIA (2017)

It is clear that Exelon Generation plays a dominant role in baseload power generation in the ComEd transmission zone. As such, the majority of FTRs purchased in the ComEd region by a physical participant are purchased by Exelon Generation, which we demonstrate in the following section.

3.4.2 *Exelon Generation's Hedging FTRs*

Generating stations are exposed to locational price risk when the network is congested and they have power contracts that settle at nodes different from their own. Figure 11 provides one example of this potential price risk in ComEd. Figure 11 displays the distribution of LMP congestion component differences between the LaSalle Nuclear Power Plant and the Northern Illinois Hub in 2017. This distribution was approximated using nonparametric kernel density estimation with rule-of-thumb bandwidth selection (Henderson and Parmeter, 2015). The crucial feature of this density estimate (and of many other generator-to-hub paths) is its positive skewness. Positive skewness suggests that there is a disproportionate number of hours in the year when the congestion component at the hub is much greater than the congestion component at the generator, potentially resulting in large financial losses for the generating stations if they are not adequately hedged.

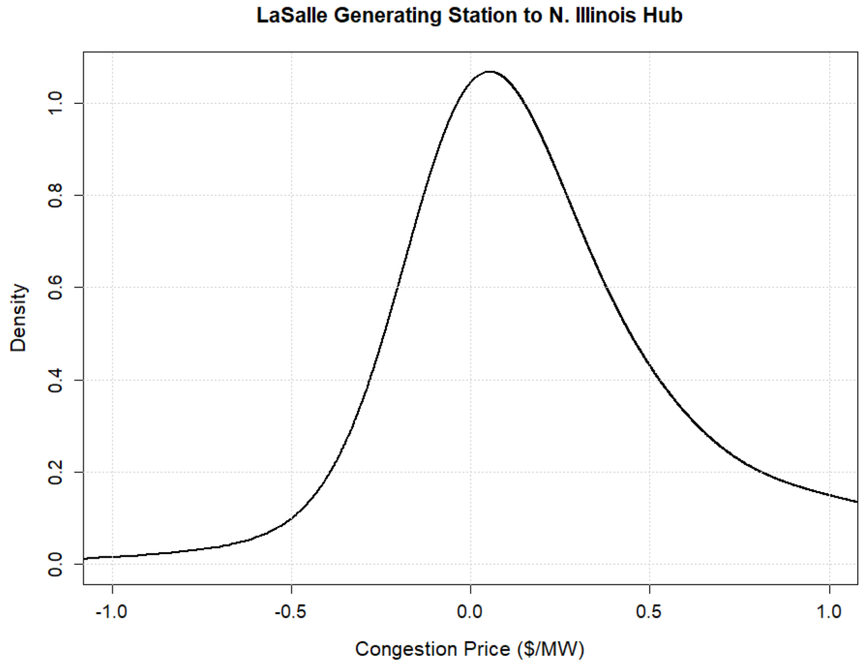

Figure 11 Kernel Density Estimate of Congestion between LaSalle Power Plant and the Northern Illinois Hub Using Hourly Congestion Prices from 2017

We identify Exelon's purchased FTRs by matching "Participant" names associated with FTRs awarded in PJM's annual FTR auction data to accounts held by Exelon Generation using the "FTR Participant List" on PJM's website. In the ComEd region, Exelon Generation has a consistent strategy of buying FTRs with the source node specified as one of their generator's nodes and the sink node specified as the Northern Illinois Hub, which is an index node composed of generation and load nodes in the ComEd region. These generator-to-hub FTRs have a distinct hedging quality because the Northern Illinois Hub is a widely traded pricing hub in complementary markets, such as futures markets. Further, the Northern Illinois Hub is a potential settlement node for privately negotiated bilateral transactions in the ComEd region. Thus, Exelon can use these generator-to-hub FTRs to eliminate locational basis risk between their generators' nodes and the forward contracting node Northern Illinois Hub.

The FTRs demanded by Exelon Generation have very similar power flow characteristics to the ARRs allocated in the ComEd zone. By definition, ARR allocations have a source node that is a generating resource in its territory, and the sink node is a weighted aggregate of individual load nodes in its territory. In our case, Exelon owns most of the generating resources that serve as the source nodes of ComEd's ARR allocations.[9] Furthermore, Exelon Generation seeks to purchase FTRs that have its own generating resources as source nodes and the Northern Illinois Hub as the sink node. Even though pricing hubs and aggregates are not indexed by exactly the same nodes, the ComEd Aggregate node and Northern Illinois Hub tend to have similar levels of congestion throughout the year. Figure 12 shows how closely the congestion component at these two nodes track each other throughout the year, meaning that the two nodes are electrically similar. The two series have a correlation coefficient of 0.99 and an average absolute deviation of 1.47 $/MW.

[9] This is inferred through a combination of resources, including PJM's "ARR Allocation Bids" and "Stage 1 Resources by Zone" documentation, as well as EIA's Form 923, which connects power plant names to plant operators.

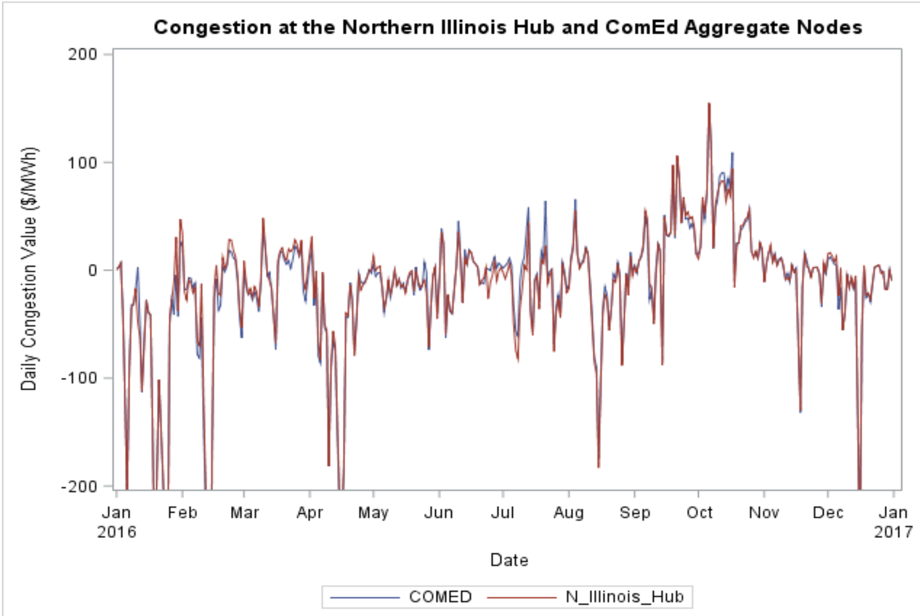

Figure 12 Congestion Component of LMP at the Northern Illinois Hub and ComEd aggregate, 2016.

PJM allows auction participants to place multiple bids for the same FTR contract path, effectively allowing participants to bid an FTR demand schedule for a given path. Figure 13 shows one of Exelon's demand schedules for FTRs between its Braidwood Power Plant and the Northern Illinois Hub from the 2016/2017 annual FTR auction in PJM. Though PJM does not reveal bidders' identities, in certain circumstances it is straightforward to unmask particular bids.[10] The figure also displays how much transmission capacity with a $0 reservation price was made available through this path's ARR configuration. Finally, the black line represents the equilibrium auction price, meaning all of Exelon's FTR bids above the black line were awarded at the market clearing price (7,286 $/MW). The difference between the supply made available by ARRs and the quantity cleared by Exelon (~50 MW) is the quantity that was purchased by participants other than Exelon.

[10] In this case, Exelon Generation was the only participant to clear FTRs on this path, so we can uniquely match their cleared FTRs to the bidding data. Furthermore, Exelon Generation often places their bid steps in equal increments (as in this case), so we can unmask their bids that do not clear the auction.

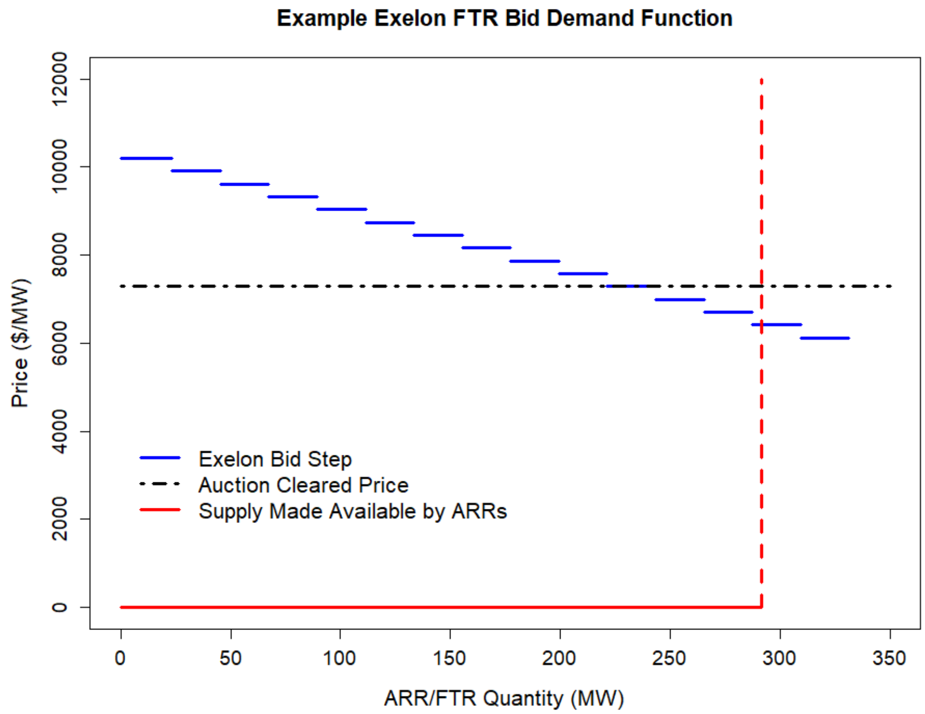

Figure 13 Exelon Demand Function for FTRs between Braidwood Generating Station and Northern Illinois Hub, 16/17 Annual Auction, Round 3

Table 12 reports the quantities of Exelon Generation's FTR purchases in the ComEd region from 2007-2018 in the annual FTR auction.[11] Note that Exelon also purchases FTRs in long-term auctions and monthly auctions, but they make the vast majority of their purchases in the annual auction. Over the sample period, Exelon shifted from purchasing large quantities of 24-hour FTRs to purchasing on-peak and off-peak FTRs separately.

[11] Included in the "24H" category are any FTRs self-scheduled by Exelon Generation. It is not clear how or why Exelon Generation receives ARRs that they can self-schedule into FTRs, but one hypothesis is that another subsidiary of Exelon Corporation called Constellation Energy receives ARRs because they are a competitive retail energy supplier who serves load in ComEd. Thus, it is possible that Constellation self-schedules some ARRs as FTRs, and PJM reports Exelon Generation as the participant who owns these FTRs because of their affiliate relationship to Constellation.

Table 12 Exelon Generation FTR Purchases in the ComEd Region

Planning Period	24H (MW)	On-Peak (MW)	Off-Peak (MW)
2007/2008	11,698	920	868
2008/2009	9,649	1,231	1,272
2009/2010	8,164	901	956
2010/2011	5,216	4,926	5,237
2011/2012	5,216	4,700	4,327
2012/2013	6,670	5,161	5,467
2013/2014	4,239	4,474	5,276
2014/2015	4,351	3,304	3,060
2015/2016	1,241	6,320	5,997
2016/2017	741	7,700	7,669
2017/2018	1,164	8,023	7,687

Source: PJM Annual Auction results (2007-2018)

Table 13 reports Exelon's total expenditures on the FTRs reported in Table 12, as well as the *ex post* realized value of these FTRs. In total, Exelon Generation spent more than $979 million on FTRs in the ComEd region from 2007-2018. The total market value of these FTRs was $1.148 billion, meaning Exelon was in aggregate able to acquire hedges below their realized market value. Despite purchasing FTRs at a price above their realized value in four of the years in our sample period, Exelon Generation netted $169 million in profits over the entire period. This is indicative of the right-tail risk (Figure 11) inherent to the congestion component of LMP in electricity markets and why it is so important for Exelon's generators to acquire FTR hedges. However, as our conceptual model suggests, the primary counterparty to this risk sharing is electricity customers.

Table 13 Exelon Generation FTR Expenditures and Realized Value

Planning Period	Total Spent on FTRs in In ComEd Region	Total *Ex Post* Value of FTRs	Exelon Generation Net Returns
2007/2008	$17,421,905	$2,078,637	($15,343,269)
2008/2009	$13,272,989	$19,682,144	$6,409,155
2009/2010	$21,367,693	$36,235,560	$14,867,867
2010/2011	$79,019,301	$100,371,442	$21,352,140
2011/2012	$118,608,442	$142,881,472	$24,273,029
2012/2013	$107,665,377	$104,943,236	($2,722,141)
2013/2014	$66,778,019	$103,172,563	$36,394,545
2014/2015	$82,502,546	$125,706,797	$43,204,250
2015/2016	$133,141,329	$210,324,634	$77,183,305
2016/2017	$219,493,980	$207,310,729	($12,183,252)
2017/2018	$119,493,450	$95,514,963	($23,978,487)
Total	$978,765,033	$1,148,222,176	$169,457,143

Source: PJM Annual Auction results and daily day-ahead market results

3.4.3 *ComEd's Minimum ARR Allocation*

In publicly available regulatory filings with the state of Illinois, ComEd is described as an LSE and thus has the right to nominate and receive ARRs (Illinois Commerce Commission, 2009). Regarding ARRs, the same regulatory filing articulates that "all proceeds and costs of such sales, including costs incurred to evaluate and execute such a strategy, should be passed to customers through ComEd's Rider PE." Thus, whatever revenues ComEd receives through auction revenue or self-scheduled FTR revenue is included as part of Rider PE (Purchased Electricity) on the electricity bills of ComEd's retail service customers. According to data available on the Illinois Commerce Commission's website, ComEd served anywhere from 27-50% of the kWh in the ComEd service territory from 2008-2017. Thus, it seems reasonable that ComEd would receive, at a minimum, 27-50% of the ARRs allocated in the ComEd transmission zone.

3.4.4 *Identifying Self-Scheduled FTRs in the ComEd Zone and ARR Value*

PJM does not report the quantity of ARRs that are self-scheduled into FTRs along a given path. However, we can infer self-schedule quantities by parsing the auction data using our qualitative knowledge of PJM rules regarding how self-scheduled FTRs clear the auction.

All self-scheduled FTRs are 24-hour products. The majority of FTRs that clear the auction are either on-peak or off-peak products, so limiting our search to only 24-hour products substantially decreases the pool of candidate self-scheduled FTRs. Further, the annual FTR auction is conducted in four rounds. PJM makes an equivalent quantity of "transfer capacity" available in each round. To do this, PJM must clear self-scheduled FTRs in equal quantities across rounds. For example, a 1 MW self-scheduled FTR from source node A to sink node B would be observed as 0.25 MW clearing from A to B in each round. Furthermore, a self-scheduled FTR is associated with a specific LSE. For our example, we would observe the same participant clearing 0.25 MW of a 24-hour product from node A to node B in each round. Table 14 reports the quantity of ARRs that were self-scheduled and the quantity that were claimed as auction revenue from 2007-2018.

Table 14 Self-Scheduled FTRs and Retained ARRs in the ComEd Zone by Planning Period

Planning Period	ARR Allocation (MW)	Self-Scheduled FTRs (MW)	Retained ARRs (MW)	Self-Scheduled Percentage
2007/2008[a]	14,617	6,657	7,961	46%
2008/2009	14,617	6,388	8,230	44%
2009/2010	14,617	5,202	9,415	36%
2010/2011	8,348	2,373	5,975	28%
2011/2012	11,740	1,998	9,742	17%
2012/2013	13,523	3,933	9,591	29%
2013/2014	10,574	750	9,824	7%
2014/2015	8,914	619	8,295	7%
2015/2016	9,572	1,241	8,332	13%
2016/2017	8,913	936	7,977	11%
2017/2018	11,527	1,164	10,363	10%

[a]We have not yet received data on ARR allocations for 2007/2008 – 2008/2009, so we use the ARR allocation for the year 2009/2010 for these years as a proxy.
Columns 3-5 are authors' calculations

Throughout the sample period, the majority of ARRs were claimed as auction revenue rather than self-scheduled into FTRs. Furthermore, the proportion of ARRs that were self-scheduled into FTRs actually decreased over time. Because PJM does not publish self-scheduled FTR quantities, there is no way to directly validate our inferred levels of FTR self-scheduling. However, we can compare our estimates to information published by Monitoring Analytics regarding the aggregate quantity of self-scheduled FTRs across all of PJM in the annual auction, and so far our results are closely aligned with their published figures.[12]

Table 15 reports the revenue that was earned in the ComEd region from ARRs in the form of auction revenue. The rightmost column of Table 15 reports the market value of these ARRs had they been converted into FTRs, which is the opportunity cost of the decision to claim ARRs as auction revenue. The FTRs had a higher market value than the ARRs in seven of the ten years.

[12] We compare our estimates to the "Comparison of self scheduled FTRs: Planning periods 2009/2010 through 2017/2018" table in the 2017 State of the Market Report

The total difference between foregone revenue of ARRs that were not converted into FTRs and realized revenue from ARR auction revenue is $237 million.

Table 15 ARR Revenue and Foregone FTR Revenue

Planning Planning	Revenue from ARRs Claimed as Auction Revenue	Opportunity Cost of Foregone FTRs
2007/2008[a]	$ 13,583,411	$ 8,435,974
2008/2009	$ 11,882,718	$ 14,743,787
2009/2010	$ 12,689,252	$ 11,691,456
2010/2011	$ 82,236,103	$ 95,437,470
2011/2012	$ 120,002,459	$ 143,728,818
2012/2013	$ 100,469,031	$ 85,055,966
2013/2014	$ 74,398,835	$ 121,834,803
2014/2015	$ 100,027,054	$ 170,117,176
2015/2016	$ 140,758,676	$ 231,271,967
2016/2017	$ 194,036,737	$ 204,837,822
Total	$ 850,084,276	$ 1,087,155,241

[a]Again, we use ARR allocations from 2009/2010 as a proxy for the preceeding two planning periods

3.4.5 *Speculator Profitability in ComEd*

Next, we consider the profitability of FTRs that were purchased in the ComEd region by market participants who do not own physical assets in PJM, which PJM classifies as “Other Suppliers.” To be considered an “Other Supplier,” a market participant cannot own generation, transmission, or distribution assets in PJM, nor can the participant be a retail consumer of electricity. Because it is impossible to know the market strategy of an Other Supplier (e.g. speculation, arbitrage, power marketing, etc.), we will describe the behavior of Other Suppliers as speculation because we assume the motivating factor of Other Suppliers in FTR auctions is realizing financial profit on average.

As we showed in the theoretical model, financial speculators can realize financial profits by capturing a price premium when ARRs are not self-scheduled into FTRs. Here, we consider

FTRs whose source node and sink node are both located within the ComEd zone. Thus, we omit FTRs whose source node is in ComEd and sink node is in a different transmission zone, and vice versa. Table 16 displays the total spent on FTRs and revenue from FTRs purchased by Other Suppliers in the ComEd region from 2007-2018. Speculators realized financial profits in all but two years in our sample. In total, speculators realized financial gains of $142 million over the sample period.

Table 16 Total Costs and Revenues of FTR Purchases by "Other Suppliers" in ComEd Region

Planning Period	Total Spent on FTRs in In ComEd Region	Total Ex Post Value of FTRs	Other Suppliers' Net Returns
2007/2008	$2,702,454	$688,998	($2,013,456)
2008/2009	$7,330,929	($6,323,603)	($13,654,532)
2009/2010	$3,720,900	$14,115,946	$10,395,046
2010/2011	$8,550,463	$14,087,165	$5,536,702
2011/2012	($777,362)	$5,885,735	$6,663,098
2012/2013	($14,945,858)	($2,813,850)	$12,132,009
2013/2014	$9,737,750	$48,827,588	$39,089,838
2014/2015	$14,369,145	$34,647,687	$20,278,543
2015/2016	$19,697,669	$45,455,294	$25,757,625
2016/2017	$81,822	$20,381,285	$20,299,463
2017/2018	($8,267,265)	$9,479,100	$17,746,365
Total	$42,200,647	$184,431,347	$142,230,700

3.4.6 *Are Exelon Generation's FTRs more profitable than their rivals'?*

We have presented summary statistics showing that Exelon Generation was able to acquire cost-effective FTR hedges over the period from 2007-2018 in the ComEd zone. Our conceptual model suggests that, at the marginal clearing price for an FTR, a speculator will also be able to acquire profitable FTR positions when transmission capacity is made available through the ARR process. Furthermore, there are other physical asset owners who purchase FTR hedges in the transmission zone. Because a disproportionate quantity of transmission capacity is allocated along Exelon Generation hedging paths, it is worth exploring whether Exelon is able to acquire more cost-effective hedges than their rivals. This is an interesting issue because if the endowment of ARRs is unequal among generating companies in terms of how much transmission capacity is made available for each generating company's hedging paths, then it is possible that some generating companies would be able to acquire more cost-effective hedges than others. If a company is able to acquire more cost-effective hedges than their rivals, it would raise issues in terms of the competitiveness of the market.

In this section, we estimate three econometric specifications to test whether 1) Exelon is able to acquire more cost-effective FTRs than other physical asset owners; 2) Exelon is able to acquire more cost-effective FTRs than speculators; 3) All hedgers (Exelon plus non-Exelon physical asset owners) are able to acquire more profitable FTRs than speculators.

In the ComEd transmission zone, the majority of transmission capacity made available through the ARR process is associated with generating stations owned by Exelon Generation. Table 17 presents the quantity (in MW) of ARRs in the ComEd zone that have a generating station owned by Exelon Generation as the source node, and "Non-Exelon" refers to ARR paths where the source node is associated with a generating station not owned by Exelon in the ComEd zone.

Table 17 ARRs in the ComEd Zone whose Source Node is Associated with Generating Stations Owned by Exelon or Non-Exelon Entities

Planning Period	Exelon (MW)	Non-Exelon (MW)	Exelon % of Total
2013/2014	7,328	2,449	75%
2014/2015	6,928	1,986	78%
2015/2016	8,033	1,540	84%
2016/2017	7,769	1,290	86%

The equation we estimate takes the general form of:

$$TargetAllocation_{i,k} = \Upsilon Auction\ Price_{i,k} + \theta Group\ Indicator_{i,k} + \boldsymbol{\beta_k} + \varepsilon_{i,k} \qquad (3.1)$$

where *Target Allocation* is an FTR's realized *ex post* value (in $/MW), *Auction Price* is the price of an FTR in the annual auction (in $/MW), and *Group Indicator* is a dummy variable that equals unity when the purchaser of the FTR belongs to a particular group (e.g. Exelon Generation) and zero otherwise (e.g. Non-Exelon). Each unit of observation i belongs to a year k. The scalar $\boldsymbol{\beta}$ controls for the k yearly fixed effects due to weather and other omitted variables. We specify the equation with an interaction term and higher-order terms of *Auction Price* to capture a more flexible response of *Target Allocation* to the independent variables.

The data used in these regressions are observations of FTRs purchased in PJM's annual FTR auction within the ComEd transmission zone over the period 2007-2018. An observation of an FTR purchased belongs to one of three groups: Exelon Generation, non-Exelon hedger, and speculator. We are constraining our definition of "non-Exelon hedgers" to only include those firms that own physical assets (i.e. physical transmission, distribution, or generation owners) as defined by PJM. Speculators are participants defined by PJM as Other Suppliers, i.e. participants who do not own physical assets in the market. Table 18 provides summary statistics for the data used in the regression. *Target Allocation* and *Auction Price* are both measured in $/MW. On average, Exelon Generation's FTRs are more expensive and ultimately more valuable than non-Exelon asset owners and speculators. Nevertheless, Non-Exelon physical asset owners and speculators are also able to acquire cost-effective hedges in the ComEd zone, on average.

Table 18 Summary Statistics for Exelon Generation Company, Non-Exelon Physical Asset Owners, and Speculator FTRs in the ComEd region from 2007-2017

	Exelon		Non-Exelon		Speculators	
	Target Allocation	Auction Price	Target Allocation	Auction Price	Target Allocation	Auction Price
No. of Obs	5,914	5,914	5,074	5,074	83,559	83,559
Mean	$ 9,314	$ 8,310	$ 1,474	$ 1,168	$ 606	$ 56
St. Dev	$ 11,722	$ 9,603	$ 8,199	$ 4,778	$ 6,999	$ 4,638
Min	$ (16,822)	$ (6,369)	$ (56,105)	$ (46,364)	$ (63,588)	$ (62,793)
Max	$ 67,783	$ 62,793	$ 66,178	$ 44,880	$ 62,012	$ 62,793

Regression one compares Exelon to non-Exelon hedgers, where the *Group Indicator* dummy variable refers to Exelon Generation. Regression two compares Exelon Generation to speculators, where the *Group Indicator* dummy variable refers to Exelon Generation. Regression three compares all hedgers (Exelon and non-Exelon) to speculators, where the *Group Indicator* dummy variable refers to financial speculators. Table 19 presents the results of the regressions. All regressions are conducted using OLS with standard errors clustered at the year level.

Table 19 Regression results comparing the cost-effectiveness of FTRs purchased by different classes of participants in the ComEd region from 2007-2018

Dependent Variable: FTR Target Allocation			
Grouping	*Exelon(=1)/ Non-Exelon*	*Exelon(=1)/ Speculators*	*Hedgers(=1)/ Speculators*
VARIABLES	(1)	(2)	(3)
Intercept	-2,682***	251***	223***
	(618.79)	(17.81)	(21.54)
Auction Price	1.23**	1.04***	1.04***
	(0.11)	(0.12)	(0.12)
Exelon	801.29	444.43	
	(597.23)	(539.70)	
Hedgers			-119.33
			(318.82)
Auction Price x Exelon	-0.20*	-0.05	
	(0.09)	(0.05)	
Auction Price x Hedgers			-0.003
			(0.05)
Auction Price^2	-1.82E-05	5.91E-06	3.78E-06
	(1.0E-05)	(3.00E-07)	(1.00E-07)
Year FE	YES	YES	YES
N	10,988	89,473	94,547
R-squared	0.72	0.56	0.56

Robust standard errors clustered at the year level
*** p<0.01, **p<0.05, *p<0.1

Our estimates do not detect a statistical difference in FTR cost-effectiveness between Exelon and non-Exelon hedgers (regression 1) or between Exelon and speculators (regression 2). When comparing all hedgers to speculators (regression 3) there is a mild reaction when the group indicator is interacted with the square of auction price, but the effect in absolute terms is extremely small. Overall, we conclude that there are no systematic differences in the cost-effectiveness of FTRs purchased by Exelon, non-Exelon hedgers, and speculators in the ComEd transmission zone from 2007-2017.

At first, it may seem surprising that Exelon is not able to acquire more cost-effective hedges than other physical asset owners. Despite the disproportionate share of transmission capacity being made available to Exelon generating stations, it is possible that the nature of network loop flows creates substantial transmission capacity on non-Exelon hedging paths as well. When the LSE who manages the ARRs associated with Exelon Generation power stations chooses to claim those ARRs as auction revenue, they create transmission capacity not just for Exelon power stations, but also for rival generating stations who are exposed to many of the same transmission constraints.

Therefore, it seems that the financial benefits that ComEd's electricity customers miss out on by not self-scheduling FTRs are captured by Exelon Generation, non-Exelon hedgers, and financial speculators. This is reasonable because all three of these groups have equal access to the FTR auction and any extra-profitable FTRs will be competed away.

3.5 Conclusions

Subsidiary relationships between a regulated LSE and unregulated market participants distort the Investor Owned Utility's incentive to maximize the value of the regulated LSE's ARRs. Our conceptual model demonstrates that, from the perspective of the IOU, the profit-maximizing strategy involves minimizing the unregulated market participants' cost of acquiring FTRs, which is equivalent to minimizing electricity customers' revenues from ARRs. The LSEs' auction revenue deficiency does not affect the profitability of the parent company because the company simply passes through ARR revenues to the LSE's retail electricity customers, whereas the profits realized by unregulated entities improve the parent company's bottom line.

Each year, thousands of ARRs are allocated in ComEd that, for the most part, are claimed as auction revenue rather than converted into FTRs. In PJM's annual FTR auction, Exelon Generation purchases large quantities of FTRs on paths where cheap supply is made available through ARR configurations in ComEd. These FTRs turn out to be cost-effective in terms of their *ex post* market value. Financial speculators also acquire profitable FTRs in the ComEd region where substantial transmission capacity is made available through the ARR process. ComEd's electricity customers lose out because they are funding the trading premium demanded by FTR buyers at the margin.

A regulatory filing by the Illinois Commerce Commission (ICC) states that "ComEd should attempt to monetize its ARR rights through a sale to other market participants thereby maximizing the value collected for such rights while limiting the risks to our customers" (Illinois Commerce Commission, 2009). While it is unclear if this is a suggestion or directive from the ICC to ComEd, it is impactful for two reasons. Taken as a directive, this would limit ComEd's strategic ability to maximize the value of their ARR allocation through a mixed strategy of claiming some ARRs as auction revenue and self-scheduling some ARRs into FTRs. At the same time, it signals to other market participants (including ComEd's unregulated affiliate, Exelon Generation) that there will be substantial FTR supply available in the annual auction, which facilitates these market participants' ability to not bid their true willingness to pay for a given FTR – they simply have to outbid other market participants who are trying to purchase profitable FTRs.

Next, the ICC quote suggests that selling ARRs in the annual auction minimizes risk to ComEd's retail electric customers. This is only true in the narrow sense that ComEd will not possess a risky asset that could potentially have a negative value. However, this ignores the crucial linkage between ComEd's ARR allocation and the congestion rent that they pay in the spot energy market. If ComEd possesses a self-scheduled FTR that has a negative value, this means that ComEd is likely concurrently paying negative congestion rent in the spot energy market, which is a financial surplus for ComEd's customers. Nevertheless, the value of the FTR and congestion rent should nearly offset one another, making the sum effect risk neutral. On the other hand, when ComEd claims ARRs as auction revenue, ComEd's customers are exposed to both negative and positive congestion events without an FTR to protect them against price spikes. And, as the positively skewed distribution of congestion rents demonstrates, ComEd's customers are disproportionately exposed to downside risk because costly congestion events are more likely than beneficial congestion events.

CHAPTER 4. RENT-SEEKING IN PJM'S LONG-TERM FTR AUCTION

4.1 Introduction

> "We participate because there's a market out there and other people are participating in it and it's not illegal and it's perfectly sanctioned. But … we're not sure that it's right that we should be allowed to participate if at the end of the day we are impacting revenues that rightfully belong to customers or opportunities to get revenues that belong to the customers, and that's our dilemma."

Quote attributed to Direct Energy's Marji Philips in *RTO Insider* (Sweeney, 2018)

PJM's market for long-term financial transmission rights (FTRs) is controversial in the sense that market advocates believe long-term FTRs are necessary to facilitate commercial activity and competition in electricity markets (Sweeney, 2018), whereas critics believe that the long-term FTR market should be eliminated (Monitoring Analytics, 2019). In between, there are market participants such as Direct Energy's Marji Philips whose company earns profits in the long-term FTR market, but are reluctant to endorse the market because it might be inhibiting the return of congestion revenue to electricity customers.

FTRs are financial derivatives which have been a component of competitive electricity market design for nearly 20 years. FTR value is based on network congestion, so they are often paired with contracts for physical power delivery as a hedge against locational basis risk in the spot energy market. All RTO/ISOs conduct FTR auctions on an annual, quarterly, and/or seasonal basis. PJM's long-term market is relatively new, having been introduced in 2009, and no other RTO/ISO has a similar long-term auction. The modifier "long-term" refers to the fact that the FTRs in the long-term market are sold up to three years before they begin to generate congestion-related cash flows.

This essay addresses the question "Do electricity customers benefit from PJM's long-term FTR auction market?" Electricity customers are effectively passive counterparties in the long-term auction, meaning that the revenue raised in the auction is ultimately passed through via customers' electricity bills. However, there is no institutional justification for requiring electricity customers to be passive counterparties in the long-term auction. Theoretically, electricity customers could be better off if the FTRs currently sold in the long-term auction were sold in later auctions, such as annual auctions. In such auctions, prices tend to be higher yielding potentially greater revenue for electricity customers. The hypothesis is customers would be better off if long-term FTRs currently sold were instead sold in later auctions.

To address this question, we study the price trajectories of two classifications of FTRs through the long-term FTR auction up to the annual FTR auction. The first classification, ARR-path FTRs, is FTRs on a pathway defined by an Auction Revenue Right (ARR). A load-serving entity (LSE) has the choice to claim the revenue from the sale of ARR-path FTRs in the *annual auction* or to retain the ARR-path FTR themselves after the annual auction. This is a relevant classification because LSEs (and their electricity customers) are not passive counterparties to the sale of ARR-path FTRs in the long-term market, but we nevertheless observe long-term auction prices for these FTRs. Thus, we can study the evolution of the market-based expected value of LSEs' ARR allocations using long-term auction clearing prices up to three years prior to an LSE's decision to sell or retain FTRs during the annual auction.

The second classification of long-term FTRs, non-ARR-path FTRs, is the set of FTRs that are actually purchased in the long-term auction. This classification of FTRs is relevant because 1) LSEs are the passive counterparty to the sale of these FTRs, and 2) these FTRs clear the auction at an apparent discount relative to subsequent auctions (e.g. the annual FTR auction). The fundamental difference between these two classifications (ARR-path and non-ARR-path) of FTRs is the quantity of administratively-determined supply of each type available in the auction.

FTRs actually purchased in the long-term market generally sell at a discount relative to their value in the annual auction. In contrast, ARR-path FTR prices exhibit the opposite behavior—their long-term price tends to be higher than their price in the annual auction. Observing the price dynamics for these two groups of FTRs reveals information regarding the time-varying markup demanded by market participants for purchasing these risky assets years before they generate congestion-based revenue.

The research question posed in this essay echoes Leslie (2018). Similar to most of the existing FTR literature (e.g., Adamson et al., 2010; Olmstead, 2018), Leslie finds that FTRs persistently sell for a price below their realized values. As addressed by Leslie (2018), we assume that financial speculators earn some trading profit for assuming the risk of holding an asset of uncertain value. Leslie studies price movements of FTR source/sink combinations that were not sold in previous rounds, concluding that financial traders confer price discovery benefits to the market and that the profitable opportunities they discover disappear after they purchase a particular FTR.

We differentiate ourselves from Leslie (2018) by studying *supply-side* liquidity in the long-term market. Technically, electricity customers are the passive counterparty to the long-term auction sale of the transmission network's "excess capacity." Excess capacity is defined as transmission capacity that is not allocated to LSEs in the form of ARRs, and is sold to long-term auction participants with a $0 reservation price. Specifically, the bids of purchasers set prices in this market. Conversely, there is no supply-side liquidity on ARR-path FTRs in the form of excess capacity – transmission capacity on ARR paths is reserved for sale (or LSE self-scheduling) in the annual auction. Thus, ARR-path FTRs can only be purchased by transacting with a willing counterparty in the auction market. We hypothesize that this contrast in supply-side liquidity drives the divergent set of price trajectories we observe between excess capacity FTRs and ARR-path FTRs.

Excess capacity can sell in the long-term auction as early as three years before the FTR is a valid market instrument, meaning the FTR buyer is placing a bid based on a congestion forecast for three years into the future. There are numerous potential changes to fundamental market conditions over a span of three years, including transmission upgrades, generation expansions and unit retirements, changes in relative fuel prices, demand growth, changes to market structure and rules. Moreover, there are the usual risks associated with potential forced and unforced outages of generators and transmission lines during the marketing year that are unknown during the long-term market. In short, there are numerous market uncertainties that could impact future congestion patterns on the network, suggesting a potentially large risk component to long-term FTR payoffs.

We begin by discussing the mechanics of PJM's long-term FTR market and provide descriptive results of market profitability and competition from the past 10 years. An analysis of price trends of purchased FTRs follows in Section 3. In Section 4, we analyze ARR prices in the long-term auction and the relationship between long-term FTR prices and annual prices along ARR paths. A final section provides conclusions and policy recommendations.

4.2 PJM's Long-Term FTR Auction

PJM introduced the long-term FTR auction in 2009 as a supplement to the existing annual and monthly FTR auctions. In this section, we describe the timing and auction mechanics of PJM's long-term auction. We also provide a mathematical definition of "excess capacity," which is the portion of network transmission capability that is sold in the long-term auction. There is no excess capacity available for sale on ARR paths. The majority of revenue from the sale of excess capacity is allocated to LSEs, who in turn pass the revenues through to their electricity customers.

4.2.1 *Long-Term Auction Mechanics*

FTRs are purely financial products whose payoffs depend on future congestion conditions in the day-ahead energy market. An FTR is defined by its injection and withdrawal points on the transmission network and its capacity in megawatts. The stream of payoffs to an FTR is determined by summing, over all the hours the FTR is a valid market obligation, the difference between the congestion component of the nodal price at the withdrawal point and the injection. For a complete description of FTR payoffs, see Leslie (2018).

Whereas all RTO/ISOs conduct annual and seasonal FTR auctions, PJM is the only RTO that conducts a long-term FTR auction. It is called a long-term auction because the FTRs sold in the auction do not begin generating congestion-based cash flows until 1-3 years from the auction date. For example, the FTRs sold in the long-term auction in calendar year 2019 are forward market obligations for a one-year period within June 2020 – May 2023. There are three products sold in the long-term auction, where each product covers a full year. Note that PJM classifies one planning period or calendar year for FTRs as June through May of the following year. So for example, in the long-term auction held in 2019, the three products available are full-year products (shorthand name for the product is in parentheses):

1) June 2020 – May 2021 (YR1)
2) June 2021 – May 2022 (YR2)
3) June 2022 – May 2023 (YR3)

PJM conducts its long-term auction in three rounds. The first round of the long-term auction occurs (approximately) in June, the second round in September, and the third round in

December. Given this market timing, a market participant has many opportunities to acquire an FTR along a given path for a particular planning period. Consider an FTR from A→B that is valid during the planning period June 2022 – May 2023. In the long-term auction held in 2019, a participant has three rounds (June, September, and December) to bid on A→B as the YR3 product. In the 2020 long-term auction, a participant has three rounds to bid on A→B, but this time it is the YR2 product. In the 2021 long-term auction, a participant has three rounds to bid on A→B as the YR1 product. Finally, in the annual auction conducted in 2022, a participant has four rounds to bid on path A→B. Figure 14 illustrates the opportunities that a bidder has to acquire an FTR for a given planning period through the long-term and annual auctions.

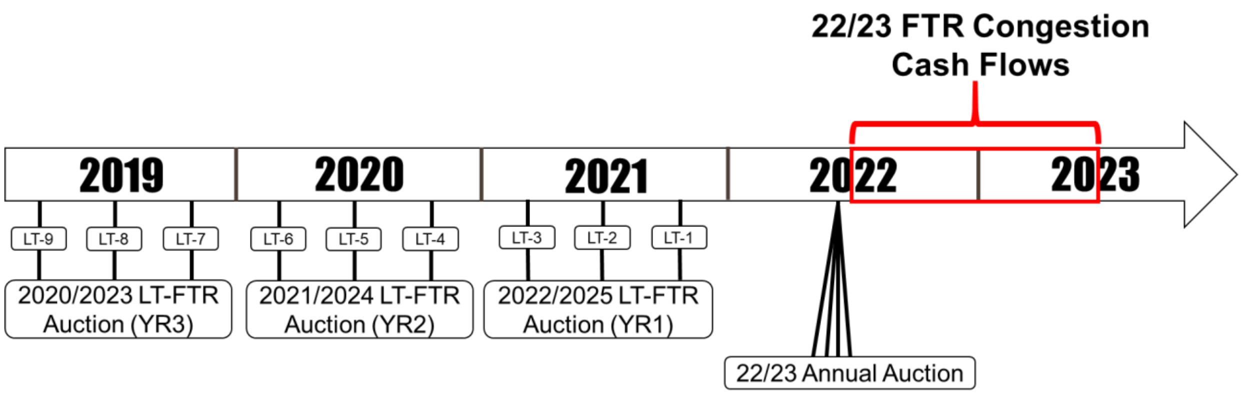

Figure 14 Timing of PJM's long-term and annual auctions leading up to the 2022/2023 planning period

Note: The long-term auction occurs in three rounds per year (June, September, and December) while the four rounds of the annual auction all occur in April preceding the start of a planning period on June 1.

Given the timing of auctions outlined above, we can view the long-term market as a sequence of auctions. We use the naming convention LT-i, i=1…9, which denotes an FTR purchased in the i^{th} closest long-term auction round to the annual auction for a given planning period. For example, “LT-1” refers to the final long-term auction round preceding the annual auction for a given planning period.

PJM does not auction off ARR system capability in long-term auctions; ARR system capability is "reserved." That is, ARR allocations in a given year are carved out of the long-term auction market model. For example, all cleared 2019/2020 ARRs are carved out of the concurrent long-term auction (i.e., 2020/2023 auction), and whatever transmission capability that remains is called excess capacity. In the context of the mathematical programming model that solves the long-term FTR auction, the right-hand-sides of ARR-path FTR transmission constraints are set to zero while the right-hand-sides of non-ARR-path FTR transmission constraints are nonnegative (Figure 15).

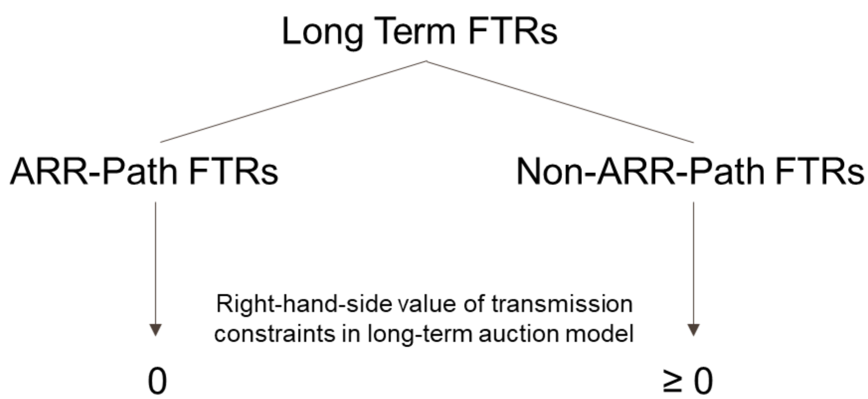

Figure 15 Availability of Transmission Capacity on ARR-path and Non-ARR-path FTRs in the Long Term Auction

A mathematical formulation of the optimization model used to settle FTR auctions, including the impact of the ARR process in the annual auction, is presented in the first chapter of this dissertation. To be concise, here we consider only the right-hand-side of the Simultaneous Feasibility Conditions used in the auction formulation. In the context of the long-term auction model, any non-zero element of these right-hand-sides is called excess capacity.

To calculate excess capacity, consider the following notation. There is a set of ARR allocations where one allocation is denoted $A_{i,j}$ which specifies the quantity in MW from source node i to sink node j. Each transmission line k in the network has a rated carrying capacity L_k (in MW). The shift factor matrix $f_{k,i}$ denotes the impact of a 1 MW injection of power at node i on line k. The power flow on the k-th transmission line, p_k, due to the set of ARR allocations is calculated by first calculating the net injections at each node i due to the set of ARR allocations and then multiplying nodal net injections times the shift factor matrix for the network $f_{k,i}$, as in (1):

$$p_k = \sum_{\mathrm{i}=1}^{\mathrm{n}} f_{k,i} \left\{ \sum_{j \neq i} \left(A_{i,j} - A_{j,i} \right) \right\} \tag{4.1}$$

If the power flow any line k is less than the carrying capacity for the line, L_k, then there exists excess transmission capacity on that line e_k.[13] Then,

$$e_k = L_k - |p_k|, \tag{4.2}$$

For a given year's long-term auction, an equal quantity of excess capacity is auctioned off in each of the three rounds. The sale of excess capacity generates revenue that is first used to ensure that FTR holders receive 100% of the Target Allocations defined by their FTRs.[14] Once all FTR holders are made whole in terms of receiving their full Target Allocations, then the remaining long-term auction revenue is allocated to LSEs on a proportional basis, as defined in Section 8 of PJM Manual 28. Thus, revenue raised from excess capacity sold in the long-term FTR auction in a particular transmission zone is not allocated solely to the LSEs in that transmission zone – it is allocated proportionately to all ARR holders in PJM.

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[13] The flow on a line can be negative, in which case $-p_k \geq -L_k$ in the FTR auction formulation. The sign of flows on a line is determined arbitrarily by the construction of the shift factor matrix, which has to be defined directionally.

[14] If the ISO/RTO assumes the network has more transmission capacity in the snapshot network used in FTR auctions than is actually available in the spot energy market, then the congestion rent collected by the ISO/RTO will be insufficient to cover all outstanding FTR target allocations.

4.3 FTRs Purchased in the Long-Term Auction

The profitability of FTRs is the *ex post* realized value (Target Allocation) of the FTRs minus the price paid. We examine who is buying long-term FTRs by using PJM member classifications (Generation Owners, Transmission Owners, Electric Distributors, End-Use Customers, and Other Suppliers), and discuss two simple measures of competitiveness in the auction. We then study the price trajectories of FTRs that were purchased in the long-term auction market, with the goal of gaining an understanding of how market prices evolve over time. This investigation is relevant because electricity customers are counterparties to FTRs that are sold years in advance; however, it may be the case that these FTRs could raise more revenue for electricity customers if sold in a later auction. All of the data used in this section comes from data available on the PJM website. We use results of the long-term FTR auctions, daily day-ahead energy market results, and PJM member classifications to generate tables and figures.

4.3.1 *Descriptive Statistics Regarding Outcomes in Long-Term Auctions*

Table 20 provides a summary of the gross revenue spent on FTRs and their associated target allocations, which are the *ex post* realized values of the long-term FTRs, for the planning periods 2011/2012 – 2017/2018. It indicates, for a given planning period, how much was spent on buy bids that cleared the auction for YR1, YR2, and YR3 products that correspond to that planning period. For example, for planning period 2017/2018, the table reflects the auction price and realized value of YR3 products sold in the 2015/2018 long-term auction, YR2 products sold in the 2016/2019 auction, and YR1 products sold in the 2017/2020 auction.

Table 20 Summary of Total Price Paid and Target Allocation for Cleared Buy Bids by Planning Period in PJM's Long-Term FTR Auction

Planning Period	Total Paid	Total Target Allocation	Total Profit
2011/2012	$42,402,892	$121,116,745	$78,713,853
2012/2013	$49,494,041	$102,624,323	$53,135,638
2013/2014	$67,847,283	$164,604,732	$96,757,448
2014/2015	$52,255,661	$243,114,509	$186,667,818
2015/2016	$52,081,491	$131,352,803	$78,528,093
2016/2017	$66,853,253	$86,114,187	$19,260,934
2017/2018	$40,609,232	$78,427,312	$37,818,080
Total	$371,543,853	$927,354,611	$550,881,865

The difference between the total target allocation and total price paid represents the total profitability of the long-term FTRs. On average, FTRs sold in the long-term auctions for planning periods 2011/2012 through 2017/2018 for approximately 40% of their realized *ex post* value for a nominal profit greater than $550 million. Most of these profits were captured by what PJM categorizes as an "Other Supplier." By definition, an Other Supplier does not own generation, transmission, or distribution assets in PJM, nor do they qualify as an end-use-customer of electric power. Other Suppliers could be competitive LSEs, power marketers, or financial speculators. Table 21 lists Other Suppliers' purchases of FTRs in MW, dollars, and total profits for a given planning period.

Table 21 Percent of all MW Purchased, Total Spent, and Total Profit Earned by Other Suppliers on Buy Bids in PJM's Long-term FTR Auction

Planning Period	% of MW	Total Paid ($)	Total Profit ($)
11/12	92%	$ 8,560,025	$ 101,900,599
12/13	94%	$ 19,685,834	$ 67,922,748
13/14	92%	$ 6,404,687	$ 62,965,878
14/15	93%	$ (3,261,343)	$ 134,740,487
15/16	94%	$ 20,569,303	$ (2,755,298)
16/17	94%	$ 28,667,196	$ 2,790,116
17/18	95%	$ 20,022,325	$ 40,571,708
Total	93%	$ 100,648,026	$ 408,136,238

Note: Total Paid can be negative (as in 14/15) because FTR auction prices are often negative, meaning the FTR buyer is paid money to hold a risky asset that may have a negative expected payout in the future.

Across the seven planning periods, Other Suppliers accounted for 93% of cleared MWs of FTR purchases in the long-term auction. Other Suppliers failed to earn a profit in only one of these planning periods, and their total spent on FTRs is less than 25% of their realized total profit.

A common concern in the FTR literature is whether the market is competitive (e.g. Olmstead, 2018). Table 22 provides two measures of market concentration in the long-term auction, the Herfindahl-Hirschman Index (HHI) and four-firm concentration ratio (C4). The HHI measures, for each planning period, the sum of squared market shares of purchased FTRs (in MW) for each firm in the long-term market and the C4 calculates the share of FTR purchases (in MW) of the four firms that purchased the most FTRs for a given planning period. These are weak measures of market structure because FTRs are inherently heterogeneous products. The underlying heterogeneity stems from the fact that two FTRs with different sources and sinks will create implied power flows across different transmission constraints, and thus congestion in different areas of the transmission network determine their payoffs. However, the products are not independent because their auction prices and payouts are determined simultaneously.

Table 22 Number of Bidders Clearing an FTR Buy Bid and Herfindahl-Hirschman Index and Four Firm Concentration Index for Cleared FTRs by Planning Period

Period	# of Unique Participants	HHI of Cleared MW	C4 of Cleared MW
11/12	64	922	53
12/13	62	1,243	62
13/14	68	742	42
14/15	71	750	44
15/16	81	887	50
16/17	87	733	46
17/18	97	505	36

For each planning period, there are over 60 unique participants in the long-term auction market. Given the HHI for each planning period, the market would be characterized as unconcentrated by the U.S. Department of Justice guidelines, which states any market with an HHI below 1500 is considered unconcentrated. Furthermore, the four largest firms in the long-term market capture approximately 40-60% of the market, suggesting that there are well over four firms who are heavily engaged in the market.

The descriptive evidence does not suggest that the market is uncompetitive from an aggregate point of view. In order to fully address the question of market structure, we would require access to the network parameters used in the auction to understand whether there is competition for available capacity on each transmission constraint, as well as market shares of implied power flows for each transmission constraint.

The following section provides analysis of price trends of purchased FTRs in the long-term auction. Given the preceding analysis, we assume that the auction is competitive and that the marginal bidder in most cases is a participant classified as an Other Supplier.

4.3.2 *Price Convergence of Purchased FTRs*

Like any type of forward market, there exists uncertainty about future market conditions at the moment when a long-term FTR is sold. This uncertainty is resolved incrementally, and long-term market prices should converge to actual congestion costs over time. Here, we consider a simpler type of price convergence, which is the convergence of long-term FTR prices to the prices of the same FTRs in the annual auction. We focus on these price trajectories because FTRs sold in the long-term auction could instead be sold in the annual auction, so we are essentially studying electricity customers' opportunity cost of selling FTRs in the long-term auction versus the annual auction.[15]

Figure 16 depicts three price trajectories of long-term FTRs, purchased in three different rounds of the auction, up to the annual auction. One price trajectory, denoted LT-9 in Figure 16, is made up of all FTRs purchased in the LT-9 round of long-term auctions for planning periods 2011/2012 through 2017/2018. The horizontal axis treats the nine long-term auction rounds and the annual auction as categories. For each auction round, we calculate the value of the basket of LT-9 FTRs using that round's clearing prices divided by the basket's value using annual auction clearing prices. Thus, the measure is deterministically equal to one in the annual auction category. Any value above one for a given auction round suggests that the basket of FTRs was valued greater in that round than it was in the annual auction. Conversely, a value below one suggests the basket of FTRs was valued less in that round than it was in the annual auction. For the LT-6 and LT-3 plots, the broken lines indicate the values of the purchased FTRs in the rounds leading up to their actual purchase.

[15] The comparison is flawed because shifting excess capacity to the annual auction from the long-term auction would create a supply shock in the annual auction, and thus would impact (i.e. weakly decrease) equilibrium annual auction prices.

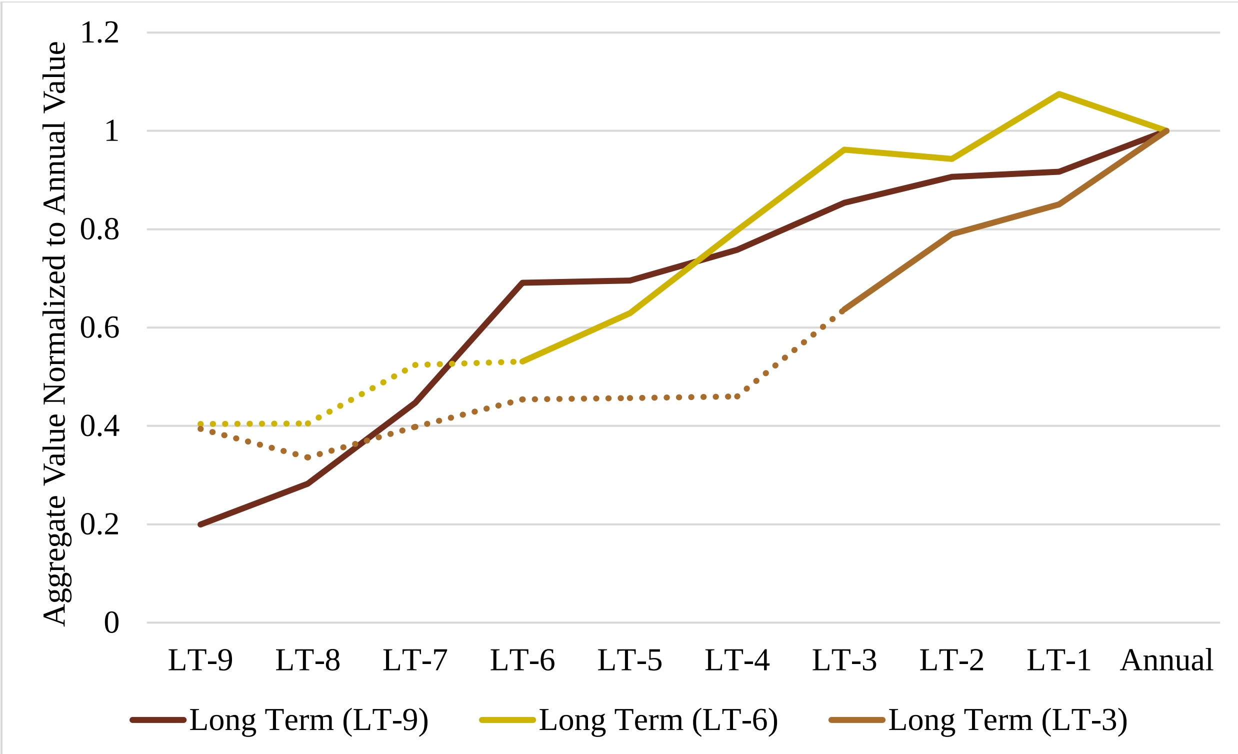

Figure 16 Price Convergence of Long-Term FTRs to their Annual Value

The value of each of the three LT-FTR products depicted in Figure 16 increase in value relative from the time they are purchased up until the annual auction. As we would expect, the LT-9 FTRs are purchased at the lowest value relative to their annual value due to the additional uncertainty associated with the longer lead time before congestion payments begin flowing, and the LT-3 FTRs have the highest value relative to their annual value at the moment of their purchase. The values of the LT-6 and LT-3 FTRs preceding their purchase (the broken lines in Figure 16) suggest they were increasing in value prior to their purchase.[16] This is not surprising because uncertainty regarding the underlying product (future transmission congestion) is resolved incrementally, and thus the risk premium associated with the product decreases over time. The risk premium decreases over time as 1) uncertainty about future market conditions is resolved, and 2)

[16] Even if a particular source/sink is not purchased in a given auction round, we can still calculate that FTR's auction clearing price because the math program that solves the auction produces nodal prices for every node on the network.

the time-to-market decreases, meaning the collateral cost of locking money into long-term FTRs is decreasing the closer we are to the planning period. Given there are only seven years' worth of data in the sample, small anomalies can appear in the series (such as the LT-6 FTRs' rise above a value of 1 in the LT-1 auction) due to an idiosyncratic price movement in just one year.

4.3.3 *Purchased FTRs by Source/Sink combination*

One type of hedging FTR is defined by a generator node as its source node and an exchange-traded load-zone or hub as its sink node. The reason this is a typical hedging FTR is because it is relatively easier to sign a forward bilateral contract (or acquire a futures contract) for energy at a hub or zone than it is at any individual node (e.g. generator node) on the network. Then, with a contract to buy or sell power at a zone or hub, a "hedging" FTR effectively moves the location of price certainty from the hub or zone (the sink of the FTR) to the generator node (the source of the FTR). For example, the vast majority of ARR-path FTRs (which are supposed to provide some form of a hedge) are defined with a generator at the source node and a load-zone at the sink node. Figure 17 displays total expenditures and profits on three source-sink pair types: Gen-Gen, Gen-Hub, and Gen-Zone.

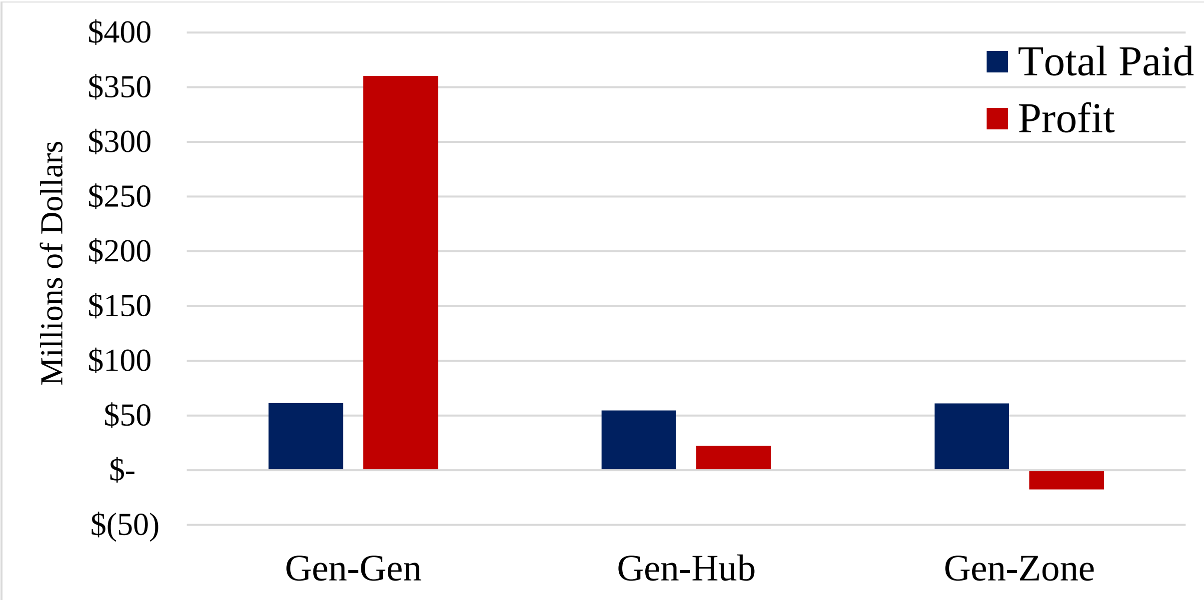

Figure 17 Long-Term FTR Expenditures and Profits by Source-Sink

Note: ARR-path FTRs are typically defined as sourcing from a generator node and sinking at a load-zone node.

Nearly 70% of FTRs purchased in the long-term auction (by MW) have a generator node as both the source and sink node. These FTRs earned total profits greater than $350 million on total expenditures of approximately $50 million. Market participants spent approximately the same amount of money on Gen-Hub and Gen-Zone FTRs, which typify hedging FTRs, but made substantially less profits. In fact, Gen-Zone FTRs, which are defined like ARR-path FTRs, had negative profits. By definition, there is no transmission capacity available on Gen-Zone FTRs because that transmission capacity is reserved for sale in the annual auction. In order to buy a Gen-Zone FTR, an auction participant must purchase the FTR from a counterparty, and the counterparty is likely a financial speculator who demands a risk premium for selling the FTR.

4.3.4 *GreenHat Energy*

Recently, the long-term FTR auction has been roiled by the default of GreenHat Energy, LLC. GreenHat apparently exploited PJM collateral rules to obtain a massive long-term FTR portfolio while only having to post a minimal amount of collateral. While the collateral rules were insufficient to slow down GreenHat's acquisition of unprofitable FTRs, an independent review of the situation found that "PJM did not have the staff with the necessary training and credentials to successfully manage the financial risks" posed by GreenHat and other traders (Anderson and Wolkoff, 2019). Ultimately, GreenHat's FTR positions will have to be liquidated or otherwise paid for by the remaining PJM market participants. The total size of the default is expected to range from tens to hundreds of millions of dollars.

Since GreenHat's default, PJM has taken swift action to increase collateral requirements for all FTR market participants. The GreenHat saga may increase the risk premium demanded by long-term FTR bidders in two ways: 1) the increase in collateral requirements effectively increases transaction costs associated with purchasing long-term FTRs, and 2) market participants may be more wary of, and price accordingly, potential counterparty default risk. Additionally, the increase in collateral requirements may be viewed as an increased barrier to entry to the long-term market if a potential entrant is discouraged to participate because of the magnitude and duration of the collateral requirement in the long-term market.

4.3.5 *Discussion*

The long-term market is highly profitable, yet seems to be competitive from an aggregate perspective. We cannot properly assess the competitiveness of the long-term market because we do not have access to the network parameters used in the FTR auction. One explanation for the high observed profits in the market is a potentially large market-based risk-adjusted rate of return demanded by market participants for holding a risky asset for up to three years before the asset generates cash flows. The risk premium appears to shrink as we get closer to the annual auction, which is supported by the theory as uncertainty is resolved incrementally and transaction costs decrease over time as the opportunity cost of capital decreases.

Other Suppliers, who do not own physical assets in the market, are the purchasers of most long-term FTRs. Moreover, the most profitable type of FTRs that are purchased have a generator at both the source and sink nodes, making them hard to construe as having a hedging purpose. Thus, it seems likely that long-term FTRs are purchased for the purpose of financial speculation.

4.4 Relationship to ARR Process

PJM reserves transmission capacity in the long-term FTR auction so that all ARRs can be self-scheduled in their respective planning period without violating the simultaneous feasibility conditions. Specifically, there is little or no excess capacity along ARR-path FTRs in the long-term market. If a participant wants to purchase an ARR-path FTR in the long-term auction, they will likely have to purchase that FTR from a counterparty who is selling the FTR or is buying a counterflow FTR on the same path. This counterparty will demand (in expectation) some level of return for their participation, meaning that the ARR-path FTR buyer will have to pay a premium (in expectation) in order to purchase an ARR-path FTR.

Figure 18 depicts the price trajectory of ARR-path FTRs from the earliest long-term auction (LT-9) up to the annual auction. Like in the previous section, the value for a given round is normalized to the annual auction value. There are two major differences between the ARR-path FTR price trajectory and the purchased FTR price trajectories depicted in the previous section. One difference is that throughout the long-term auction, ARR-path FTRs are valued higher than they are in the annual auction. The normalized value of ARR-path FTRs hovers around 1.3 throughout the long-term auction, meaning the long-term auction clearing prices of ARR-path FTRs are roughly 30% higher than they are in the annual auction.

The second important feature is the precipitous price decline between the LT-1 and the annual auction. This is the only major round-to-round price change in the price series. In this section, we argue that this price decline is due to the supply shock that occurs in the annual auction from ARRs entering the market. The nature of the price shock is this: in the long-term auction, the auction clearing price is the result of buyers and sellers coming together to determine an auction clearing price. In the annual auction, ARRs that are claimed as auction revenue are sold with a reservation price of $0, which infuses a supply of FTRs at rates below the long-term market level. This shock of supply then decreases the equilibrium auction price, as is depicted in Figure 18.

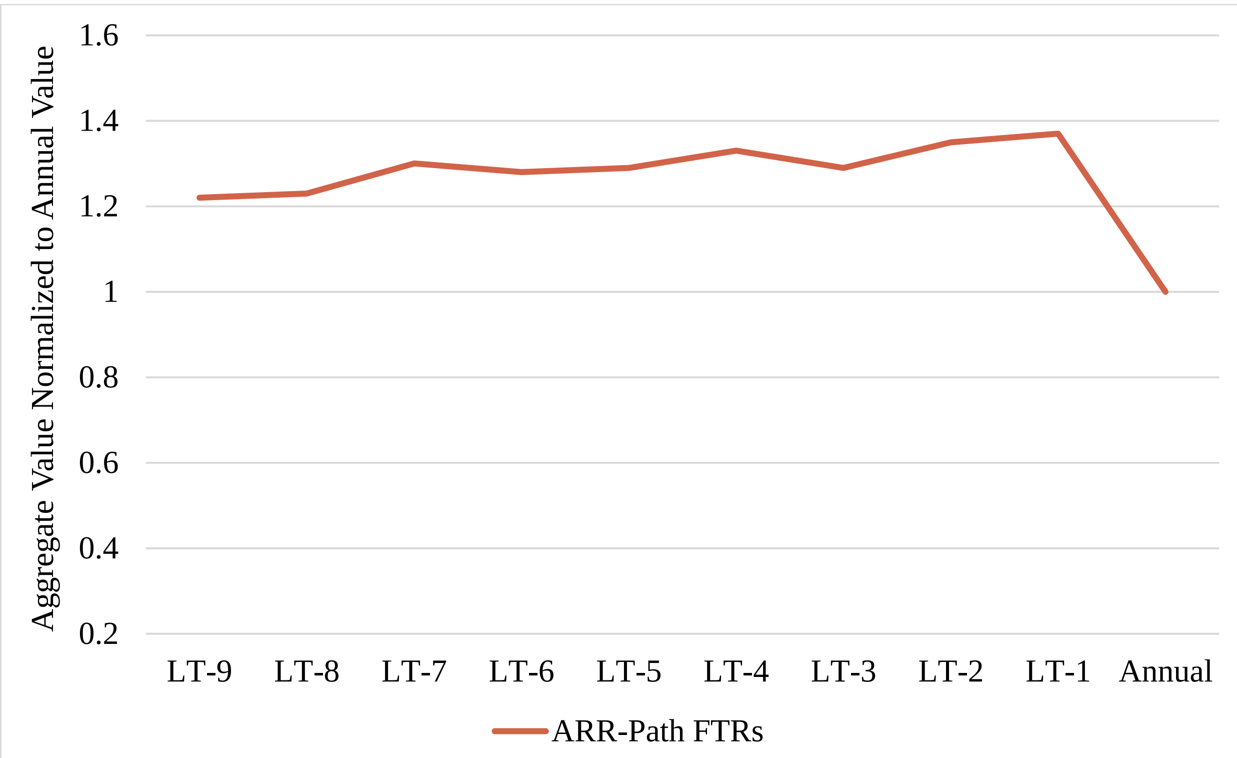

Figure 18 Price Convergence of ARR-path FTR Values to Annual Value

The price decline between LT-1 and the annual auction is problematic for LSEs because they have to make a decision about what proportion of their ARR allocation to claim as auction revenue versus self-scheduling into FTRs. One component of this decision making is a forecast of how much auction revenue an ARR will yield. Naturally, the long-term auction would seem to be a good resource for making this projection. However, as evidenced in Figure 18 and Figure 19, LT-1 prices provide a biased forecast of expected revenue from ARRs.

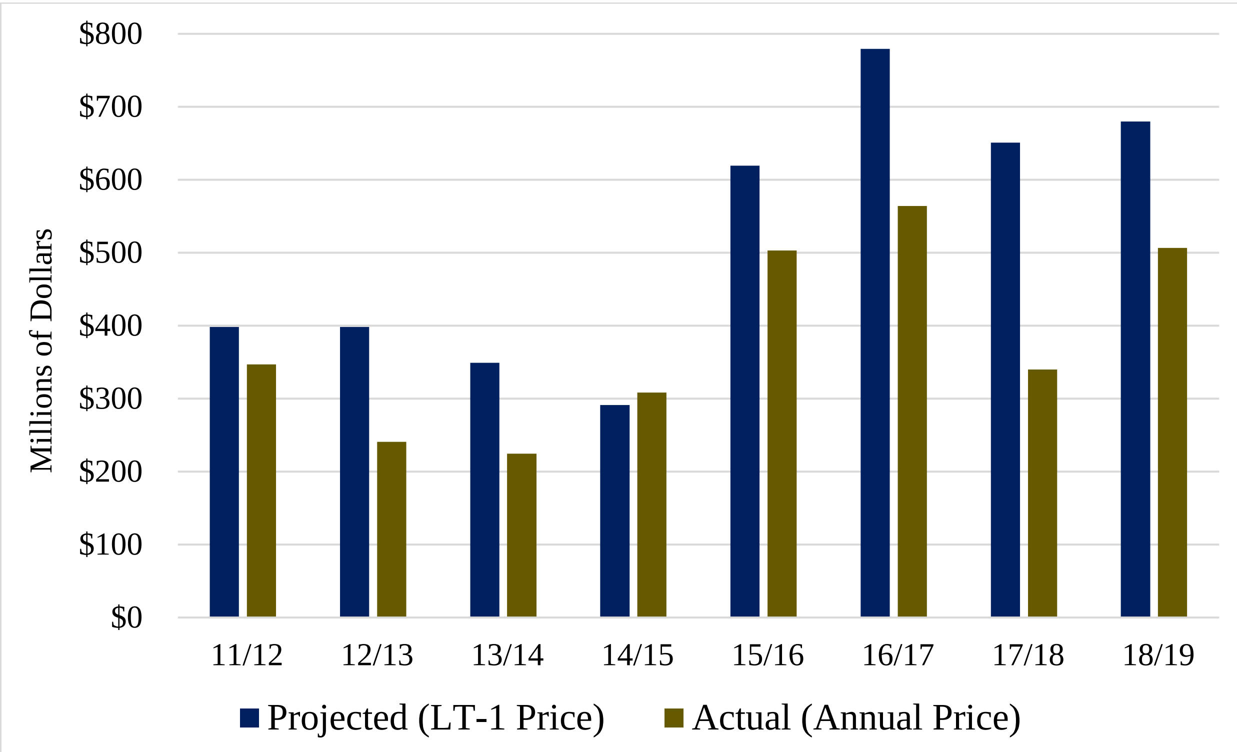

Figure 19 Projected ARR Revenue Using Long-Term Prices and Actual ARR Revenue

In Figure 19 we see that LT-1 auction clearing prices consistently overestimate the revenue that ARRs will earn in the annual auction. Only the planning period 14/15 is an exception, where the polar vortex occurred between the LT-1 and annual auction, which likely caused auction participants to increase their expectations for FTR revenues for the following year. In total, LT-1 auction prices overestimate ARR revenue by more than one billion dollars over the last eight planning periods.

Given the timing and structure of FTR auctions, we can use outcomes from the long-term and annual auctions to further our understanding of the impact of the ARR process on annual auction prices. We hypothesize that increasing the quantity of ARR supply on an ARR-path FTR will decrease the annual auction clearing price for that FTR relative to its price from the long-term auction, where there was no supply. The following sections describe the data and empirical strategy we use to test this hypothesis.

4.4.1 *Data*

All of the data used in this section is (or used to be) publicly available on the PJM website. The central data used in this section are the set of ARR allocations in PJM for planning periods 2011/2012 – 2018/2019. We supplement these eight years of ARR allocations with each ARR's auction clearing price (averaged over the four rounds of the annual auction). For each ARR allocation, we measure the quantity (in MW) that was claimed by the LSE as auction revenue (i.e. not self-scheduled as an FTR). The procedure for this measure is detailed in chapter 2 of this dissertation. We also supplement each ARR with its own price in the long-term auction immediately preceding the annual auction. For example, for the 2018/2019 ARR allocations, we supplement each ARR allocation with its own price from the third round of the 2018/2021 long-term auction for YR1 products. This auction price is the most recent market signal of the ARR allocation's expected value.

4.4.2 *Empirical Strategy*

In this section, we investigate whether the supply shock caused by the inclusion of ARR supply in the annual FTR auction explains a decrease in the annual auction price of ARR-path FTRs versus their price in the long-term auction. To do this, we estimate regressions of the following general form:

$$Annual\ Price_{i,j,k} = \Upsilon LongTermPrice_{i,j,k} + \theta Path\ Capacity_{i,j,k} + \boldsymbol{\lambda}_{j,k} + \varepsilon_{i,j,k} \qquad (4.3)$$

The variable *Annual Price* is the average annual price for ARR allocation *i* in transmission zone *j* and planning period *k*. The variable *LongTermPrice* is the ARR allocation's price in the long-term auction (LT-1) from the December prior to the annual auction. The variable *Path Capacity* measures the quantity (in MW) of ARR supply (i.e., non-self-scheduled ARRs) in the annual auction. The λ parameters capture region-year fixed effects to account for the fact that congestion forecast for an entire transmission zone can change between the December long-term auction and April annual auction.

We expect the parameter θ to be negative because increasing supply through the ARR process (while holding long-term auction price constant) should coincide with a decline in the annual auction price due to the rightward supply shift. We expect the coefficient on *Long Term (LT-1) Price*, Υ, to be close to unity because of the tight relationship between the sequential price of an asset.

4.4.3 *Results*

Table 23 presents the results of the estimation with the econometric specification in (3) as well as four additional regressions. Regression one has no fixed effects, while regressions two and three have a region-year or region fixed effect, respectively. Regressions four and five employ the dependent variable *Price Difference* which is calculated as *Annual Price – Long Term (LT-1) Price* regressed on *Path Capacity* and different levels of fixed effects.

Table 23 Results of Regressions Estimating the Impact of ARR Path Capacity on Annual Auction Prices

	Dependent Variable: Annual Auction Price			Dependent Variable: Price Difference	
VARIABLES	(1)	(2)	(3)	(4)	(5)
Intercept	-1,472***				
	(179.39)				
Long-Term (LT-1) Price	0.96***	0.99***	0.96***		
	(0.03)	(0.08)	(0.10)		
Path Capacity	-9.55***	-10.51**	-8.43*	-11.26***	-10.59***
	(2.10)	(4.61)	(4.73)	(2.21)	(2.56)
Region-Year FE	NO	YES	NO	YES	NO
Year FE	NO	NO	YES	NO	YES
N	7,472	7,472	7,472	7,472	7,472
Adj. R^2	0.86	0.90	0.87	0.23	0.04

*** p<0.01, **p<0.05, *p<0.1.

Regression 1 reports Pooled OLS with heteroskedastic-robust standard errors. We do not report the intercept for regressions 2 and 3 because its interpretation depends on the arbitrarily omitted region-year suppressed from the regression. Standard errors are clustered at the region-year level in regressions 2 through 5.

The results of all five regressions suggest there is a statistically significant, negative effect of *Path Capacity* on *Annual Price* (when controlling for *Long-Term Price*) and on *Price Difference*. The magnitude of the effect range from a decline of 8.43 to 11.26 \$/MW in the equilibrium annual auction price from the LT-1 price for each MW of *Path Capacity* that is introduced as a supply shock in the annual auction. For regressions one through three, we cannot reject the null hypothesis that the coefficient on *Long-Term (LT-1) Price* equals one.

4.4.4 *Placebo Tests*

As a placebo test, we consider the same main specification in (3) except our dependent variable is the long-term auction price (LT-1) and we include the long-term auction price (LT-2) as an independent variable. Effectively, we are simply moving the time-window of our regression back one period. This is an appropriate placebo test because there is no supply shock from ARR supply in either LT-8 or LT-9, so we should not expect to find a statistically significant coefficient on *Path Capacity*.

$$LT\text{-}1\ Price_{i,j,k} = \ \Upsilon LT\text{-}2\ Price_{i,j,k} + \theta Path\ Capacity_{i,j,k} + \boldsymbol{\lambda}_{j,k} + \ \varepsilon_{i,j,k} \tag{4.4}$$

Table 24 Results of Placebo Regressions

	Dependent Variable: Long Term Price (LT-1)		Dependent Variable: Long Term Price (LT-2)	
VARIABLES	(1)	(2)		
Long Term (LT-2) Price	1.08***	1.07***		
	(0.04)	(0.04)		
Long Term (LT-3) Price			1.06***	1.05***
			(0.04)	(0.03)
Path Capacity	-2.11	-1.20	-0.54	0.12
	(2.09)	(1.97)	(2.29)	(2.26)
Region-Year FE	YES	NO	YES	NO
Year FE	NO	YES	NO	YES
N	7,472	7,472	7,472	7,472
Adj. R^2	0.97	0.96	0.97	0.96

*** p<0.01, **p<0.05, *p<0.1, standard errors are clustered at the region-year level.

In each case, the coefficient on *Path Capacity* is not statistically significant. The R-squared of each regression is higher than the main specification because there is very little variation in ARR-path FTR prices between long-term auction rounds.

4.4.5 *Absence of Price Convergence*

We have presented substantial evidence that prices for ARR-path FTRs decline from the long-term auction to the annual auction because there is a supply shock in the annual auction. From the perspective of a financial trader, this would seem to suggest there is a currently uncaptured profit opportunity in the market. Following the adage "buy low, sell high," one could sell an ARR-path FTR in the long-term market (high price) and buy an ARR-path FTR in the annual auction (low price). In practice, selling an ARR-path FTR would be executed by buying a counterflow ARR-path FTR in the long-term market.

First, it is necessary to point out that this is not an arbitrage opportunity. There is approximately a four-month gap between the LT-1 auction and the annual auction. So, there is plenty of time for the realization of some uncertainty (e.g. the availability of a generator or transmission line in the coming planning period) that would cause a shift in market expectations about FTR values, and thus threatening any presupposed arbitrage opportunity.

One plausible explanation for the lack of price convergence for ARR-path FTRs between the LT-1 and annual auction is a large bid-ask spread in the long-term FTR auction. It’s possible that, for an ARR-path FTR in the long-term auction, there is little or no demand at the auction clearing price, and so the auction clearing price is set by the marginal (i.e. cheapest) supply offer. In fact, FTR buyers could be anticipating the supply shock that will arrive in the annual auction, and so have little incentive to try to acquire an ARR-path FTR in the long-term market. Thus, the ability to execute price convergence for ARR-path FTRs between the LT-1 auction and annual auction is hampered by insufficient demand-side liquidity at the auction clearing price in the LT-1 auction.

However, given the complex nature of the FTR product, we cannot derive a measure of demand-side liquidity for a given FTR in either the long-term or annual auction without knowing the network parameters. Studying the demand curve for a given source/sink combination is more complicated than looking at auction bids for that source/sink combination. We must also consider bids for any other source/sink combination that creates implied power flow across the same transmission constraints as the source/sink that we wish to study. However, it is impossible to know the implied power flow of any source/sink without knowing the network parameters used in the auction model.

4.5 Conclusion

Financial speculators have earned hundreds of millions of dollars in profits from PJM's long-term FTR market in the last decade. The counterparties to the sale of these FTRs are LSEs, who in turn pass through the auction revenue to their customers' via their electricity bills. In theory, PJM's long-term FTR auction generates congestion-related price signals that can be used to plan future resource allocation efficiently. One example would be for the planning of transmission expansion projects, where a relatively high long-term FTR price for a given path signals the demand for increased transmission capacity along that path. Likewise, a relatively high long-term FTR price could signal a potentially profitable opportunity for a merchant generator to build a resource in a highly congested (in expectation) area. However, we are not aware of a transmission or generation owner (or other entity) citing long-term auction market prices as a rationale for an investment decision.

If there are no physical efficiency gains from the sale of excess capacity in the long-term market, then financial efficiency gains are the only potential justification for the sale of excess capacity. However, greater than 90% of long-term FTRs are purchased by Other Suppliers, many of whom are financial speculators. Support for the sale of excess capacity in the long-term FTR market appears to be rent-seeking on the part of these speculators. Without evidence that the profits earned by Other Suppliers in the long-term market are (at least partially) passed through to the electricity customers who pay for the physical transmission network, the impact of these markets amounts to a financial transfer from electricity customers to long-term FTR market participants.

Nevertheless, LSEs (and their electricity customers) do not need to be passive counterparties in the long-term FTR auction in order for the auction to generate market prices. In the context of the mathematical program that solves the FTR auction, the right-hand sides of the simultaneous feasibility conditions can be set to zero, meaning the auction will not generate any revenue, yet FTR bidders can still purchases FTRs from one another through multilateral trading. In this way, the market will still send price signals which can be used to plan future resource allocation, but electricity customers will not have to pay the large risk premiums to FTR buyers for which substantial evidence was presented in this essay.

When there is excess transmission capacity for sale on non-ARR paths, the long-term market generates systematically biased price signals for ARR-path FTRs relative to non-ARR-path FTRs. The systematic bias is exhibited in the sign of the risk premium, which is positive for ARR-path FTRs and is negative for non-ARR-path FTRs. The reason for the bias is due to the excess supply available on non-ARR-path FTRs that is not available on ARR-path FTRs. Moreover, auction clearing prices of ARR-path FTRs in the long-term market provide biased projections to LSEs for expected ARR revenue in the annual auction. The long-term market provides a biased projection because in the annual auction, there is a supply shock of transmission capacity from the ARRs themselves. This in turn decreases equilibrium prices in the annual auction for ARR-path FTRs. It is possible that if the long-term market did not sell excess capacity, then the categorical bias of risk premiums between ARR and non-ARR-path FTRs would diminish.

CHAPTER 5. CONCLUSION

Financial Transmission Rights have been sold in auctions for nearly two decades. Consistent with the existing literature, this dissertation finds that the auction price of FTRs in PJM are, on average, less than the FTRs' realized value. It is important to understand why FTR auction prices do not fully converge to their realized value because the revenue raised in FTR auctions is passed through to electricity ratepayers, and thus ratepayers (potentially unknowingly, and without any control) have a financial stake in the outcomes of FTR auctions.

This dissertation advances the understanding of price formation in FTR auctions by examining the impact of the Auction Revenue Rights process on fundamental supply conditions in the auction market. Conceptually, when an ARR holder increases the quantity of transmission capacity available to bidders in the auction by claiming an ARR as auction revenue, the ARR holder effectively shifts the transmission capacity supply curve to the right. This decreases the value of the associated ARR and generates potentially profitable opportunities for FTR buyers. We hypothesize that financial speculators who participate in FTR auctions demand a trading premium to participate in the market, which encompasses the participant's risk premium and transaction costs.

The first essay provides empirical evidence that the decisions made by LSEs to self-schedule or claim ARRs as auction revenue directly affect the value of an ARR, as predicted by the conceptual model. The empirical strategy in the first essay exploits variation in ARR management strategies in PJM from 2007-2018 and is robust to numerous specifications. This essay also finds that demand-side hedging pressure has the predictable effect of decreasing an ARR's target allocation relative to its auction price, though this result is not statistically significant. We also observe a trend of decreasing ARR self-scheduling over time, where 70% of ARRs were self-scheduled into FTRs in 2007 decreased to 30% self-scheduling in 2018. There is also a negative correlation between whether a state has competitive retail choice and the propensity to self-schedule ARRs into FTRs.

The second essay details a situation where a regulated LSE does not self-schedule their ARR allocation into FTRs, thus increasing market supply of FTRs in their region. A major purchaser of FTRs in this region is a corporate affiliate of the LSE. This affiliate appears to have a sophisticated bidding strategy that minimizes the cost of acquiring a portfolio of hedging FTRs, which consequently minimizes the amount of revenue passed through to the LSE's electricity customers. This essay shows that the LSE could have increased the amount of revenue passed through to their ratepayers if they had self-scheduled their ARRs into FTRs – instead, the affiliate company was able to purchase their portfolio of hedging FTRs for a profit. This arrangement is beneficial from a corporate perspective because profits earned by the unregulated affiliate impact the corporation's bottom line, whereas ARR (or FTR) revenues earned by the regulated LSE bypass the corporate balance sheet as they are passed through to ratepayers. Other entities in the region benefit from the ample supply of FTRs, including non-affiliated hedgers and financial speculators.

The third essay shifts focus from the annual FTR auction to the long-term auction. In the long-term auction, "excess capacity" of the transmission network is sold to bidders with a $0 reservation price. This excess capacity is sold at a large discount relative to its potential sale price in the annual auction. The primary participants in the long-term market are financial speculators, who have earned hundreds of millions of dollars in profits over the ten years that the long-term market has existed. Contrary to the price trajectory of excess capacity FTRs, ARR-path FTR prices are higher in the long-term market than they are in the annual auction. This essay provides empirical evidence that the supply shock that occurs in the annual market due to the ARR process explains a large portion of observed price decrease between the long-term auction and annual auction.

Taken together, these three essays demonstrate the role of the ARR process in determining equilibrium FTR auction prices. Not only do ARR management decisions directly affect auction prices, but ARRs are the actual mechanism used to distribute auction revenues to LSEs which are ultimately passed through to ratepayers. Thus, any discussion of a shortfall in auction revenue pass-through to ratepayers must consider whether ARRs are self-scheduled or not and the consequences of the ARR management decision on equilibrium auction prices. Furthermore, it is important to consider the incentives an LSE faces when they decide whether to self-schedule their ARRs or not. There are numerous potential factors, for example corporate structure or regulatory guidelines, that can influence an LSE's ARR decision making that leads to lower observed auction prices.

One limitation of this dissertation is we do not know the firm to which ARR paths and quantities are allocated. Thus, we do not study questions related to firm-level strategic behavior over time, differences in ARR management strategies across regulated and unregulated firms, etc. This is relevant because successful ARR management strategies employed by a firm (either regulated or unregulated) potentially could be adopted by other regulated firms at little cost. Likewise, with firm-level data, it would be straightforward to identify which firms have been the least successful with their ARR allocations, which could be of interest for state regulators.

Another limitation is that we do not have access to the network parameters used by PJM to solve the auction optimization problem. Therefore, we are not able to quantify the quantity and location of transmission capacity that is not allocated to LSEs in the ARR process but is nevertheless sold in the annual FTR auction. This is problematic for empirical analysis of ARR management strategies in the annual auction because excess capacity can spill over into ARR paths through the phenomenon of loop flows, which would mean that our measure of *Path Capacity* could underestimate (or overestimate) actual supply.

This dissertation should provide a first step towards other areas of research related to ARRs. One potential extension of this work is an analysis of electricity bills within a state where LSEs have divergent ARR management strategies. If a researcher can acquire electricity bill data from multiple LSEs, a difference-in-difference approach could be used to estimate the causal impact of ARR management strategies on monthly electricity rates. The analysis would still be challenging given the complexity of electricity bills and potential timing mismatch across LSEs in terms of when ARR revenues are passed through onto electricity bills. Another promising avenue of research is the development of an optimal ARR management strategy model for a regulated LSE. The benefit of this model is it could take the burden off of regulators who may feel compelled to direct the ARR decision making strategies of regulated LSEs regarding their ARR allocations, and instead provide an optimal portfolio given risk measures for the LSE. This type of model would require distributional assumptions for the expected payoffs of FTRs, which is a difficult task in itself.

Research on FTRs in general would benefit from a better measure of market concentration of FTR ownership. The market concentration measures used in this dissertation and elsewhere calculate market concentration at an aggregate level, whereas the ability to exercise market power in electricity markets (including FTR markets) is inherently a local phenomenon. To get a local measure of market concentration of FTR ownership, the measure must relate back to the simultaneous feasibility conditions used in the math programming model used to solve the FTR auction problem. Specifically, this market concentration measure would capture the concentration of ownership of FTRs that create flows across each transmission constraint. Whether a firm has market power in FTR ownership on a particular transmission constraint could be determined using a rule-of-thumb measure akin to the three-pivotal supplier test, which is a test used in several ISO/RTOs to measure market concentration in the energy market.

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