POWERING AMERICA: EXAMINING THE ROLE OF FINANCIAL TRADING IN THE ELECTRICITY MARKETS

HEARING

BEFORE THE

SUBCOMMITTEE ON ENERGY

OF THE

COMMITTEE ON ENERGY AND COMMERCE

HOUSE OF REPRESENTATIVES

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C O N T E N T S

Witnesses

Submitted Material

POWERING AMERICA: EXAMINING THE ROLE OF FINANCIAL TRADING IN THE ELECTRICITY MARKETS

WEDNESDAY, NOVEMBER 29, 2017

HOUSE OF REPRESENTATIVES,
SUBCOMMITTEE ON ENERGY,
COMMITTEE ON ENERGY AND COMMERCE,
Washington, DC.

The subcommittee met, pursuant to call, at 10:17 a.m., in room 2322, Rayburn House Office Building, Hon. Fred Upton (chairman of the subcommittee) presiding.

Members present: Representatives Upton, Olson, Barton, Shimkus, Harper, McKinley, Griffith, Johnson, Flores, Mullin, Hudson, Walberg, Rush, McNerney, Peters, Green, Sarbanes, Welch, Tonko, Loebsack, and Schrader.

Staff present: Samantha Bopp, Staff Assistant; Allie Bury, Legislative Clerk, Energy/Environment; Zack Dareshori, Legislative Clerk; Wyatt Ellertson, Professional Staff Member, Energy/Environment; Jordan Haverly, Policy Coordinator, Environment; A.T. Johnston, Senior Policy Advisor, Energy; Mary Martin, Chief Counsel, Energy/Environment; Alex Miller, Video Production Aide and Press Assistant; Brandon Mooney, Deputy Chief Counsel, Energy; Mark Ratner, Policy Coordinator; Annelise Rickert, Counsel, Energy; Dan Schneider, Press Secretary; Peter Spencer, Senior Professional Staff Member, Energy; Jason Stanek, Senior Counsel, Energy; Rick Kessler, Minority Senior Advisor and Staff Director, Energy and Environment; John Marshall, Minority Policy Coordinator; and Alexander Ratner, Minority Policy Analyst.

OPENING STATEMENT OF HON. FRED UPTON, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF MICHIGAN

Mr. UPTON. Good morning, everybody. So, at our last Powering America hearing, we examined the important role that consumer advocates play in the organized electricity markets. Today, our examination of these markets continues as we turn our attention to the role of financial market participants, both why they trade financial products and the effects that their transactions have in the Nation's seven RTO and ISO markets.

With us today are witnesses who have extensive experience in trading financial products on behalf of private institutions and a major utility. We also have a rep from PJM Interconnection, the world's largest wholesale electricity market and the market monitor for the California independent system operation, so welcome.

Financial market participants are playing an increasingly visible role in the organized wholesale electricity markets. It is claimed that financial transactions can improve the efficiency of the physical electricity markets by providing increased liquidity, mitigating market power, and improving price formation.

In this hearing, I hope that the witnesses will explain their perspectives regarding why we have financial trading in the organized electricity markets and how this trading affects consumers who ultimately pay for electricity services.

Each of the RTOs and ISOs allow financial trading to occur in their markets including PJM and the California ISO. The most commonly traded financial products are known as financial transmission rights or FTRs and virtual transactions. While these products can by used by traditional utilities to hedge themselves against volatile price fluctuations, these products are also bought and sold by financial traders such as banks, investors, and other speculators.

While financial market participants ultimately trade to make a profit, for sure, advocates for trading claim that financial transactions strengthen the markets by increasing trading volume and liquidity which in turn reduces volatility and risk. Financial traders also claim to provide for the needs of physical market participants by offering services such as customized hedges and various types of options to limit the risk.

However, measuring the overall contribution and benefits of financial transactions in the electricity markets are certainly difficult. Critics of financial trading argue that both FTRs and virtual transactions extract value from the market without providing equivalent benefits in return. I also understand the FERC is currently reviewing several hotly debated proposals which would reduce the opportunities for virtual transactions to be used to profit from the market without adding commensurate value.

Not surprisingly, many financial traders are opposed to those proposals and as our Powering America series extends into next year, we will continue to tackle some of the most complex and challenging issues concerning both electricity markets and the energy industry. Along those lines today, our job is to take a hard look at whether FTR and virtual trading market makes sense and answer the question, does financial trading make the electricity markets more efficient and in turn result in benefits to consumers?

So with that I yield to the ranking member of the subcommittee, my friend from Illinois, Mr. Rush.

[The prepared statement of Mr. Upton follows:]

PREPARED STATEMENT OF HON. FRED UPTON

Good morning. At our last Powering America hearing, we examined the important role that consumer advocates play in the organized electricity markets. Today, our examination of these markets continues as we turn our attention to the role of financial market participants—both why they trade financial products and the effects that their transactions have in the Nation's seven RTO and ISO markets.

With us today are witnesses who have extensive experience in trading financial products on behalf of private institutions and a major utility. We also have a representative from PJM Interconnection—the world's largest wholesale electricitymarket; and the market monitor for the California Independent System Operator. Welcome.

Financial market participants are playing an increasingly visible role in the organized wholesale electricity markets. It's claimed that financial transactions can improve the efficiency of the physical electricity markets by providing increased liquidity, mitigating market power, and improving price formation. In this hearing, I hope the witnesses will explain their perspectives regarding why we have financial trading in the organized electricity markets and how this trading affects consumers who ultimately pay for electricity services.

Each of the RTOs and ISOs allow financial trading to occur in their markets, including PJM and the California ISO. The most commonly traded financial products are known as "Financial Transmission Rights" or "FTR's" and "Virtual Transactions." While these products can be used by traditional utilities to hedge themselves against volatile price fluctuations, these products are also bought and sold by financial traders such as banks, investors, and other speculators.

While financial market participants ultimately trade to make a profit, advocates for trading claim that financial transactions strengthen the markets by increasing trading volume and liquidity, which in turn reduces volatility and risk. Financial traders also claim to provide for the needs of the physical market participants by offering services such as customized hedges and various types of options to limit risk.

However, measuring the overall contribution and benefits of financial transactions in the electricity markets is difficult. Critics of financial trading argue that both FTRs and virtual transactions extract value from the markets without providing equivalent benefits in return. I also understand that FERC is currently reviewing several hotly debated proposals which would reduce the opportunities for virtual transactions to be used to profit from the market without adding commensurate value. Not surprisingly, many financial traders are opposed to these proposals.

As our Powering America series extends into next year, we'll continue to tackle some of the most complex and challenging issues concerning both the electricity markets and the energy industry. Along those lines, today, our job is to take a hard look at whether FTR and virtual trading makes sense and answer this question: Does financial trading make the electricity markets more efficient, and in turn, result in benefits to consumers?

I look forward to the testimony of our witnesses.

Mr. UPTON.

So with that, I yield to the ranking member of the subcommittee, my friend from Illinois, Mr. Rush.

OPENING STATEMENT OF HON. BOBBY L. RUSH, A REPRESENTATIVE IN CONGRESS FROM THE STATE OF ILLINOIS

Mr. RUSH. Well, thank you, Mr. Chairman. And Mr. Chairman, I want to applaud you for holding this important hearing today.

While we have an opportunity to examine the witnesses before us, we will be looking at the role of financial trading within the electricity markets. Mr. Chairman, while this may appear to be an obscure topic that the American people and even members of the subcommittee may not be intimately familiar with, it is important to keep in mind that these financial trading tools directly impact the cost that consumers pay for their electricity.

In reviewing the testimony for today's hearing, Mr. Chairman, there seems to be unanimous agreement that financial tools such as FTRs as well as day-ahead forward and real-time spot markets play key roles in improving the efficiency of the physical electricity market by providing increased liquidity, mitigating market power, and decreasing price volatility, all of which ultimately benefit America's consumers.

Additionally, Mr. Chairman, it has been noted that the FTRs provide forward pricing that helps gauge the need for additional infrastructure investment so that unnecessary construction and the subsequent costs associated with overbuilding are not passed on to the consumers.

However, Mr. Chairman, while all of our witnesses agree that these financial trading tools are indeed necessary, there also seems to be a consensus that some modifications may in fact be needed in order to ensure that these markets are operating in a way that is transparent, that is open, that is fair, and that is competitive. The discrepancy within the testimonies center around what reforms might be needed in order to adequately achieve these objectives.

Specifically, Mr. Chairman, I look forward to hearing the panelists on two pending reform proposals forwarded by PJM that FERC is currently considering regarding the up-to Congestion or UTC transactions and how FERC's decision will impact consumers. Additionally, I am interested to hear from our panelists on the recent DOE notice of proposed rulemaking and whether they support or oppose FERC providing additional subsidies to some form of generation, coal or nuclear, over and above other resources.

Finally, Mr. Chairman, it can be no surprise that for me the most important factor in deciding whether any reforms are needed, with the panel, how they might impact consumers. I look forward to engaging our witnesses or their ideas for ensuring that RTOs and ISOs are first and foremost responsive to the needs of the customers.

Additionally, I want to make sure that FERC has the tools, expertise, willingness, and authority to administer these financial markets in a way that would be fair, transparent, open, and competitive so that consumer interests are in fact the guiding principles and the most important priorities of the RTOs and the Commission.

Mr. Chairman, I look forward to this hearing.

Mr. UPTON. Thank you, my friend.

It is my understanding that two other subcommittees are meeting at this same time, so Chairman Walden is going put his statement into the record. Are there any Members on our side that would like to use part of his 5 minutes?

Seeing none, is there anyone on your side that needs Mr. Pallone's time?

Mr. RUSH. Ranking Member Pallone is also at another hearing.

Mr. UPTON. So we will allow those opening statements to go in.

[Mr. Walden's and Mr. Pallone's statements appear at the conclusion of the hearing.]

Mr. UPTON. So we will move to the testimony, to our distinguished panelists. We are first joined by Wesley Allen, the CEO of Red Wolf Energy Trading, on behalf of the Financial Marketers Coalition.

Thank you all in advance for submitting your testimony so that we could see it yesterday. And if you would summarize, each of you your testimony, in no more than 5 minutes, at which point we will do questions from the Members that are here.

So Mr. Allen, welcome. You are recognized for 5 minutes. Thank you.

STATEMENTS OF WESLEY ALLEN, CHIEF EXECUTIVE OFFICER, RED WOLF ENERGY TRADING, ON BEHALF OF FINANCIAL MARKETERS COALITION; ERIC HILDEBRANDT, PH.D., DIRECTOR, DEPARTMENT OF MARKET MONITORING, CALIFORNIA INDEPENDENT SYSTEM OPERATOR CORPORATION; MAX J. MINZNER, PARTNER, JENNER & BLOCK, LLP; NOHA SIDHOM, CHIEF EXECUTIVE OFFICER, TPC ENERGY, LLC, ON BEHALF OF THE POWER TRADING INSTITUTE; VINCENT P. DUANE, SENIOR VICE PRESIDENT, LAW, COMPLIANCE & EXTERNAL RELATIONS, PJM INTERNCONNECTION, LLC; AND CHRISTOPHER MOSER, SENIOR VICE PRESIDENT FOR OPERATIONS, NRG ENERGY, INC.

STATEMENT OF WESLEY ALLEN

Mr. ALLEN. Good morning, Chairman Upton, Ranking Member Rush, and members of the subcommittee. Thank you for inviting me to share our opinions of the electricity markets. My name is Wesley Allen. I am CEO of Red Wolf Energy Trading, a small trading firm headquartered in Raleigh, North Carolina. I am representing the Financial Marketers Coalition which is a group of similarly situated companies transacting in the ISO/RTO markets.

Red Wolf is a small company. We employ about a dozen employees scattered around the United States specializing in transacting the ISO/RTO energy markets. First and foremost, we support competitive markets. The transactions that we engage in clear the ISO day-ahead markets and then settle on the real-time. While we have been around for about 10 years, the type of activity we engage in has been around for longer and started when FERC began restructuring the electricity markets in the early 2000s.

The purpose behind restructuring was to add competition and liquidity, price transparency, and to shift risk from consumers to investors. While the road to the restructuring wasn't always smooth, after almost 20 years I believe it has been a success although there is room for improvement. The trading we do broadly is called virtual trading. Every ISO/RTO in the country allows virtual trading with one exception, the western Energy Imbalance Market.

When the FERC was restructuring the electricity markets they realized without participation by companies like ours many of the goals they were trying to achieve would not be possible. One of the goals of restructuring was breaking up natural monopolies. Financial participation is the engine that drives competition and liquidity in the transparent RTO/ISO markets.

Specifically, we engage in three types of transactions: an increment offer which sells electricity, a decremental bid which buys, and, lastly, a more refined ISO/RTO market such as ERCOT, a point-to-point transaction which is a basis or spread trade that transacts on the congestion between two locations on the transmission grid.

Electricity is uniquely localized, and without participation in these markets generation and load-serving entities could exercise market power. Generation can exercise market power by economically withholding the electricity they supply. They could sell less power in the day-ahead but at a higher price. Think of what OPEC does in the oil markets.

But not all generation withholding is nefarious in nature. Some is risk management. Contracts awarded in day-ahead are financially binding. Some generators may opt not to schedule their full output in case the wind doesn't blow or if they should have an equipment failure. Likewise, load can do something similar by underbidding their load and therefore buying most of their needs at a lower day-ahead price, then purchasing the remainder in the real-time. In these cases, virtual traders such as ourselves are assuming the risk that the utilities are unwilling to take.

The purpose of the day-ahead is to pre-position the markets for the needs the next day. Electricity being a high/low class, it is necessary not only to commit the right amount of generation, but to commit generation in the right location in order to have an efficient and reliable market. Given the natural monopolies to the market power that would otherwise exist, financial participation is critical.

A great deal of time in today's hearing will be spent on the forward markets. While efficient forward markets are critical, so is price formation in day-ahead and real-time energy markets. If prices are incorrect in the day-ahead and real-time, then the wrong signals will be sent to the forward markets. The FERC has been working on price formation for some time now. The conclusions and improvements they have been working towards are going a long way to improve the markets. My only regret is it is taking a long time.

Our participation in these markets has been under attack. Some have grown weary of competition and long for the former structure. That said, there have been a couple of notable electricity economists that through analyzing market outcomes have put a dollar figure on the efficiency gained by our participation. Dr. Wolak found that our participation in the California ISO increased market efficiency in the first year of virtual trading by $70 million per year.

Additionally, Wolak found that by more efficiently committing and dispatching resources, our trading, virtual trading reduced greenhouse gas emissions by somewhere between 650- and 537,000 tons annually. Dr. Patton, the independent market monitor at MISO, found that at a minimum financial market activity added $65 million in increased efficiency.

While most recognize that virtual trading adds efficiency in RTO/ISO markets, more could be achieved. Nearly half of all virtual transactions at less refined ISOs are done in a price-insensitive manner. More refined ISOs allow basis tradings, specifically ERCOT. Dr. Patton has been advocating for this product at MISO for over 5 years. With implementation scheduled for several years from now, we believe these critical changes are taking too long.

In conclusion, virtual traders add efficiency to ISO/RTO markets by injecting competition and liquidity that would be absent without them. Thank you and I look forward to your questions.

[The prepared statement of Mr. Allen follows:]

Written Testimony of

Wesley Allen
CEO, Red Wolf Energy Trading
On Behalf of the Financial Marketers Coalition

Before the
House Energy Subcommittee

Hearing on
"Examining the Role of Financial Trading in the Electricity Markets"
November 29, 2017

Financial trading and the presence of financial market participants play a critical role in allowing the regional electricity markets operated by the independent system operators ("ISO") and regional transmission organizations ("RTO") (collectively, "ISO/RTO") to deliver benefits to all participants in those markets, including consumers. Unique among market participants, financial participants focus solely on how prices are formed, and profit only when they contribute to better forward market prices. The same incentives do not exist for physical participants, meaning that the only stakeholders working to ensure that the ISO/RTO markets provide useful price signaling for short-term and long-term decision-making are financial participants.

Market Basics

Broad themes like liquidity, price formation, outcome forecasting, competition and efficiency are central to any discussion of how markets work, but truly appreciating the value that financial participants drive in the context of regional electricity markets comes from better understanding the nuts and bolts of the markets, and the predictable ways in which they fail in the absence of financial participants.

The ISO/RTOs operate a number of markets that provide price signals for a range of times, ranging from minutes to years into the future. Financial transactions in the ISO/RTO wholesale markets happen primarily in the longer-term Financial Transmission Rights ("FTR") auctions which will be addressed by a colleague on the panel, and the Day-Ahead markets. I note there is also energy derivatives trading outside of the ISO/RTO markets, such as on the Intercontinental Exchange ("ICE") and other platforms, but derivatives are outside the scope of our conversation today.

The cornerstone of ISO/RTO markets is Locational Marginal Pricing ("LMP"). All of the ISO/RTO markets differentiate pricing by location. All demand and supply pay (or are paid) the same prevailing price, and that price is the marginal cost of satisfying the next megawatt of demand. LMP consists of three components:

- **System Energy Price**: the price of serving the last MW of demand across the entire grid
- **Marginal Loss:** a *de minimis* amount reflecting grid conductor properties
- **Congestion Price**: This is only non-zero when the system is constrained – i.e., when lower cost units could produce more if not for grid transmission issues

The congestion component is the driver of different prices in different locations on the grid. When constraints in grid transmission restrict the availability of generation, prices differentiate resources near to demand from those that are far away, or that cannot reach demand due to the unavailability of constrained transmission lines.

The power of LMP is that it intertwines short-term dispatch instructions with clear signaling to the rest of the market. Lowering the output of a given plant is accomplished by sending that particular plant (and other generators in the same region) a lower price. Should other plants need to produce more power, those plants and others nearby are signaled to do so by a higher price.[1] In each case, the short term outcome (more or less power) is accompanied by a transparent signal to any other interested stakeholder: lower prices equate to relatively less need, and higher prices equate with relatively more need.

These market signals are sent through the Day-Ahead (forward) and Real-Time (spot) markets. The Real-Time market thus relies heavily on the Day-Ahead market to posture the right resources to allow for reliable operation of the grid; failure of the Day-Ahead market to make

[1] ISO/RTO operators retain the ability to dispatch specific facilities as needed, through out-of-market mechanisms, including to meet reliability needs.

those correct resources available results in high volatility in the Real-Time market, as the system operator struggles to satisfy instant demand, with a set of resources poorly matched to the location and magnitudes of demand.

Unfortunately for the grid operator, the Day-Ahead market naturally contains incentives for physical participants to behave differently than they will in the Real-Time market. In general, those serving load can maximize their short run profits by purchasing less power in the Day-Ahead market than they expect to use in Real-Time. By purchasing less than they know they will need, they shift the supply and demand intersection in a way that reduces price. On the other hand, generators can maximize their short run profits (or manage their Real-Time risks) by offering slightly less power into the Day-Ahead market than they expect to be able to produce. This has the effect of shifting the supply demand intersection in the opposite direction. Figures 1 and 2 demonstrate the impacts on pricing of both load (demand) and generation (supply) underbidding into the Day-Ahead market.

Fig. 1 – Example of Load Underbidding

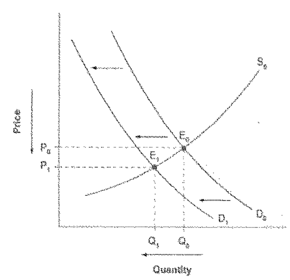
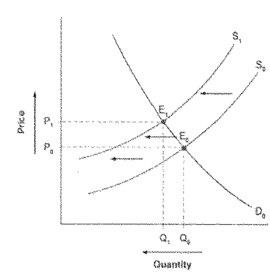


Fig. 2 – Example of Generation Underbidding



In each case, the supply curve is shifted as a result of the underbidding. In the case of load underbidding, less power is procured in the Day-Ahead market resulting in lower Day-Ahead prices. In the case of generation underbidding, less power is available in the Day-Ahead market, resulting in higher Day-Ahead prices. The market prices power on a locational basis, so both dynamics can play out at the same time at different locations on the power grid. The long term effect of this push-pull of the supply and demand curves are Day-Ahead market prices that diverge further and further from the Real-Time market. Fortunately, there are participants in the market whose sole avenue for profiting comes from identifying where the forward market is failing to price things correctly, and pushing the forward market behavior to more closely match the spot market outcomes. Figures 3 and 4, below, demonstrate how financial market participants can converge the Day-Ahead and Real-Time markets by more accurately forecasting Real-Time conditions to pre-position the Day-Ahead market.

Fig 3. Actual MISO DA Market Demand Curves, 6/3/2016, Physical Market Participants Only

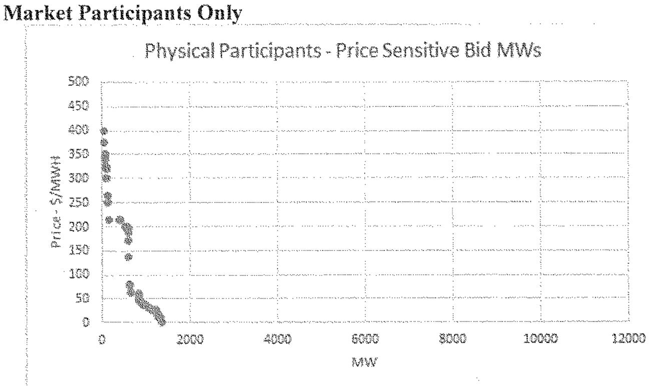
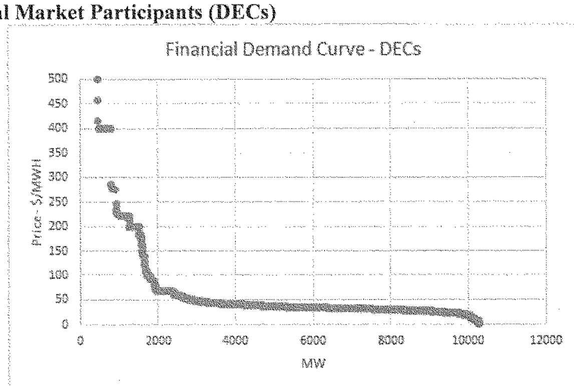


Fig. 4. Actual MISO DA Market Demand Curves, 6/3/2016, With Financial Market Participants (DECs)



On June 3, 2016 in the Real-Time, actual physical demand was 85 GW but physical load participants purchased only 95% of that amount, thus underbidding by 5% or almost 4 GW. Only 2% of the load bid in Fig. 3 was bid in a price sensitive manner. In Fig. 4 above, financial market participants added nearly 10 GW in liquidity, sending a strong signal to the market of the need for additional power.

Availability of Financial Products

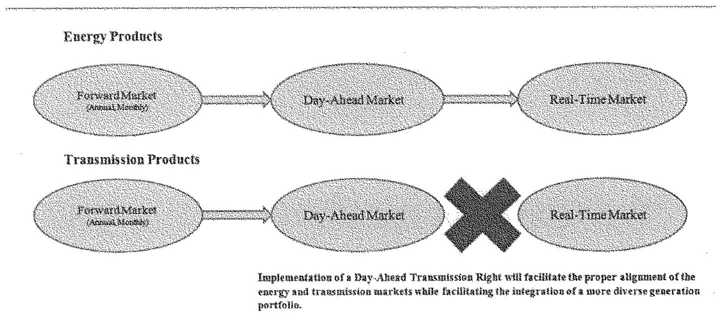
Each of the ISO/RTOs have varying financial products available. While FTRs, as well as virtual supply and demand bids, are fairly common, transmission congestion products are less common. The existence of these products is essential not only to price formation, but also the ability of market participants to hedge in a price sensitive manner. In particular, hedging is relevant not only to financial market participants, but all forms of market participants, including competitive retail electric suppliers, who need to hedge transmission congestion risks.

Fig. 5. Financial Products in the ISO/RTO Markets

ISO	Energy	Congestion	FTR	Multi-year FTR
ERCOT	✓	✓	✓	3-year
PJM	✓	✓–	✓	3-year
MISO	✓	✗	✓	✗
NYISO	✓	✗	✓	2-year
ISO-NE	✓	✗	✓	✗
CALISO	✓	✗	✓	✗
SPP	✓	✗	✓	✗

The energy products in most ISO/RTO markets are increment offers ("INC") and decrement bids ("DEC"), which allow a market participant, financial or otherwise, to take a position on the LMP at a given node. That position is exposed to all three elements of LMP: energy price, congestion and losses. As such, the position bears not only risks associated with transmission congestion, but also with resulting energy prices. A product allowing market participants to take a position on the transmission congestion between two given points without exposure to the fluctuations of energy prices, allows for more granular contributions to price formation without the risk and exposure that can prove challenging to market participants whose goal is to utilize the product specifically to hedge risk.

Fig 6. Lack of an Hourly Congestion Product is a Concern



While ERCOT offers the Point-to-Point product and PJM offers the Up-To Congestion ("UTC") product, most of the other markets do not offer a congestion and losses product in their Day-Ahead markets. We note that the ERCOT market is particularly vibrant and liquid, due in part to the presence of the Point-to-Point product, which facilitates hedging by load-serving entities.[2] While PJM does offer the UTC product, its availability is limited. NYISO, MISO and CAISO have considered adding such a product and are at various stages of development, with NYISO and MISO estimating a 2020 deployment. We believe that the expansion of financial products in ISO/RTO markets, to include the development of a congestion and losses product in the Day-Ahead market, should be a priority.

Value of Competition and Proper Price Formation

As discussed above, financial transactions move the supply and demand curve to help compensate for potential underbidding by other market participants, including load and

[2] Interestingly, in ERCOT, physical asset owners are the primary users of the Point-to-Point product, with financial market participants representing 20% or less of entities engaging in these transactions. In PJM, those numbers are reversed. *See, e.g.,* ERCOT State of the Market Report at 32, *available at* https://www.potomaceconomics.com/wp-content/uploads/2017/06/2016-ERCOT-State-of-the-Market-Report.pdf

generation. Another way to view this shift in the supply curve is through the lens of depth and liquidity, which are highly valuable and essential to market efficiency in all commodity markets. In organized markets with LMP pricing, depth and liquidity are even more essential because electricity, unlike other commodities, cannot be stored. Depth in a market is a significant number of bids and offers at each of the nodes within the system. If a load-serving entity wishes to purchase electric energy in the Day-Ahead market, it would like to see a wide variety of offers to sell, which are tightly spaced. For example:

Bid Stack A	Bid Stack B
50 MW for $50.00	50 MW for $50.00
10 MW for $65.00	5 MW for $52.00 ← INC offer
25 MW for $75.00	5 MW for $54.00 ← INC offer
15 MW for $85.00	10 MW for $55.00
	25 MW for $60.00
	15 MW for $63.00

The load-serving entity would prefer to meet its Day-Ahead needs in a market that looks more like Bid Stack B because there are more choices available to the system operator and the presence of more bids has exerted a downward pressure on the prices. In this example, the two virtual offers in Bid Stack B have smoothed out the "lumps" in the bid stack, introduced competition which has exerted downward pressure on prices, and added liquidity and depth to the market.

Additionally, electricity markets must balance every hour at every location. If demand is low in the Day-Ahead market compared to what is likely in the Real-Time market, then DECs placed in the Day-Ahead market will help bring that demand up to what it is expected to be. Conversely, if supply is low in the Day-Ahead market, then INCs placed in the Day-Ahead market will help bring that supply closer to what it is expected to be in the Real-Time market. Convergence between the Day-Ahead and Real-Time markets is important because converged markets yield lower prices to consumers. Second, energy markets are inherently volatile and risky because it can be hard for market participants to predict, in the Day-Ahead market, what the Real-Time market will look like. Financial marketers shoulder this risk on behalf of other market participants, allowing market participants to hedge the prices that they will pay against the trades placed by a financial market participant. Financial marketers also bring needed liquidity and competition to markets, and introduce competition where otherwise none (or little) may exist.

Wholesale Competitive Electricity Markets Work and Must Be Allowed to Continue Working

The Financial Marketer Coalition's focus is on strong, competitive markets. We believe that markets work and should be allowed to work with minimal government intervention, particularly in the form of out-of-market subsidies. Such out-of-market payments can distort market outcomes, yielding competitive advantages to one (or two) class of market participants, who may not otherwise be competitive. In late September, the Department of Energy submitted a draft Notice of Proposed Rulemaking ("NOPR") to FERC, proposing to compensate electric generation facilities for stockpiling fuels, in essence particularly providing subsidies to coal and nuclear fueled facilities. As you are aware, a bipartisan group of former FERC Chairmen filed comments with FERC stating that the DOE NOPR proposal will "fundamentally distort" markets, and urging FERC to reject or significantly modify the proposal.

Many have raised concerns about the potential damage to the ISO/RTO markets from financial subsidies and out-of-market payments given to certain classes of generators, particularly given the generous incentives already provided to such resources, including the benefits associated with paying the lowest effective federal tax rate of any business sector. Of the 40 U.S. publicly held utility companies that were profitable in 2015, 23 paid no federal income taxes and 16 paid no state taxes, while earning a combined $43.9 billion dollars in pre-tax profits.[3] Regulated utilities have the luxury of building corporate taxes into the rate plans set by regulators and passed on in charges to the customer. Special tax laws and utility rate plans further provide the opportunity for utilities to postpone taxes through accelerated depreciation, allowing companies to delay paying tax on the cost of their investments while receiving essentially interest-free loans. The 23 profitable utilities that paid no federal tax in 2015 reported $11.5 billion in benefits from special tax rules that allow corporations to write off the costs of infrastructure investments.[4]

A direct result of this special tax treatment is increased costs to consumers stemming from prolific and unnecessary infrastructure enhancements. Although there is a need to replace aging infrastructure and accommodate distributed generation resources, a recent trend demonstrates an increase in transmission enhancements lacking a legitimate driver such as reliability, market efficiency or operational performance criteria.[5] The majority of new transmission projects are not needed are used merely as vehicles for utilities to amortize costs and increase profits by passing on depreciation rates to customers.

The NOPR will effectively provide a bailout for utility companies making billions in profits per year, to the harm of low-income consumers. Utilities profit by purchasing power on the wholesale market and reselling the same power to retail consumers at a premium. In August, which is a peak month, the price of wholesale power in California was approximately

[3] Anderson, Sarah et al., *Utilities Pay Up: How Ending Tax Dodging by America's Electric Utilities Can Help Fund a Job-Creating, Clean Energy Transition*, Institute for Policy Studies at 1 (July, 2016), *available at* http://www.ips-dc.org/wp-content/uploads/2016/07/IPS-Utilities-Tax-Report-FINAL.pdf.

[4] *Id.*

[5] American Municipal Power, Inc., *Transmission Costs Drivers* at 10 (Sept. 21, 2017), *available at* http://www.amppartners.org/Assets/AMP_Rose_Transmission.pdf.

\$39/MWh.[6] In contrast, the price of retail power for residential end-users was 19.02 cents per kWh, or \$190/MWh.[7] In addition to profiting from the price difference between wholesale and retail power, certain types of generation resources benefit from federal and state incentive programs, such as Zero Emission Credits ("ZECs") for carbon neutral resources. Nuclear resources could be eligible for ZEC environmental subsidies even when found to be leaking radiation in the environment.[8] Providing additional subsidies to uneconomic and environmentally harmful resources is inconsistent with market fundamentals and results in actual harm to consumers. If there are important externalities that the market currently does not value, whether that is the environmental and global impact of carbon or the need for resiliency, then those externalities should be brought into the market. This has been done in other contexts – through mandatory reliability standards as well as the creation (and expansion) of the ancillary services markets within the ISO/RTO markets.

The wholesale competitive electricity markets operated by the ISO/RTOs work, and subsidies harm market equilibrium by distorting market signals and prices for consumers. The benefits brought by these markets have been quantified in many ways, including through lower costs to retail consumers in consumer-choice states. Recently the COMPETE Coalition released a report showing the demonstrable benefits of competitive electricity markets, noting that from 1997 through 2014, prices in consumer-choice jurisdictions increased 4.5% <u>less</u> than inflation,

[6] This number was calculated by Red Wolf Energy Trading internally, based on CAISO's published data.

[7] Electric Power Monthly Data for August 2017, Table 5.6.A. Average Price of Electricity to Ultimate Customers by End-Use Sector, by State (Oct. 24, 2017), *available at* https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

[8] Chase, Brett et al., *Radioactive Water Leaks from Illinois Nuclear Plants*, Better Government Association (Nov. 17, 2017), available at https://projects.bettergov.org/power-struggle/?utm_source=Sailthru&utm_medium=email&utm_campaign=Issue:%202017-11-20%20Utility%20Dive%20Newsletter%20%5Bissue:12938%5D&utm_term=Utility%20Dive.

while prices in regulated jurisdictions rose 8.4% more than inflation. Stated another way, the authors found that "[b]etween 1997 and 2014, all-sector nominal weighted average prices in Customer Choice Jurisdictions rose by 41%, but rose by 60% in the Monopoly States."[9] These prices are real costs – and real savings – to real consumers.

Academic Studies Have Confirmed and Quantified the Benefits of Financial Transactions

In the past several years, the value that financial marketers bring to the market has been questioned. Some have asked whether the value financial marketers bring to the market exceeds the value that they extract from the market. We firmly believe that financial marketers bring benefits to the market significantly in excess of the cost of their participation. A study by two economists at Stanford University found that the introduction of Convergence Bidding in California created significant economic and environmental savings for consumers.[10] The study found that those savings specifically came in two areas.

- First, the annual total cost of fossil fuel energy decreased by about roughly $70 million dollars per year in the year following the introduction of Convergence Bidding, through more efficient unit commitment.
- Second, the study found, Convergence Bidding resulted in a reduction of greenhouse gas emissions of approximately 2.8%, or between 537,000 and 650,000 pounds of emissions annually, again through better underlying unit commitment.[11]

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[9] O'Connor, P. and O'Connell-Diaz, E., *Evolution of the Revolution: The Sustained Success of Retail Electricity Competition* at 5-7 *available at* https://sites.hks.harvard.edu/hepg/Papers/2015/Massey_Evolution%20of%20Revolution.pdf

[10] JHA, A AND WOLAK, F, *Testing for Market Efficiency with Transaction Costs: An Application to Convergence Bidding in Wholesale Electricity Markets* at 23 (May 7, 2013) available at http://web.stanford.edu/group/fwolak/cgi-bin/sites/default/files/files/CAISO_VB_draft_V8.pdf.

[11] This occurred through the pre-positioning of the Day-Ahead market, allowing more efficient units to run instead of the system operator calling on less-efficient units in the Real-Time market.

At the same time that year, the profits extracted from the market by entities trading Convergence Bidding was approximately $13 million in 2011 and $18 million in 2012.[12] While this study was done in the smaller CAISO market, it shows profound savings – with Convergence Bidding bringing value ***over four times greater*** than the cost of such trading in fuel costs alone, not including the value of avoided carbon emissions, and the longer term value of better pricing in the forward market to all market participants. Specifically, the study noted:

> Although it was possible to implicit virtual bid before the introduction of explicit virtual bidding, the evidence from our analysis is that the introduction of this product significantly improved the degree of price convergence between the day-ahead and real-time markets ***and reduced the cost of serving load*** in the California ISO control area.[13]

Dr. John Parsons, in conjunction with the FERC Office of Enforcement, performed an analysis of convergence bidding in the CAISO markets, questioning the value of virtual transactions and referencing certain virtual bidding as "purely parasitic." Dr. Parsons' paper was highly skewed against virtual trading, seeking to find examples to prove that such transactions are not beneficial to competitive wholesale electricity markets. Dr. Parsons' analysis focused on ramping events in CAISO where virtual traders were consistently buying Day-Ahead energy and profiting from the ramping and scarcity pricing that occurs during the peak hours in California

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Note that the dollar value of reduced greenhouse gas emissions is not included in the $70 million savings.

[12] California Independent System Operator, *Market Issues and Performance: 2011 Annual Report* at 87 (2011), http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf; California Independent System Operator, *Market Issues and Performance: 2012 Annual Report* at 109 (2012), http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf. We note that we refer only to the profits associated with internal Convergence Bidding, and do not include values associated with Convergence Bidding at the interties or in imports/exports.

[13] Wolak Study at 23 (emphasis added). *Cf.* Parsons, J, Colbert, C., et al., Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets at 1 (Feb. 2015) (setting out to demonstrate in which circumstances virtual trading does not bring benefits, but not defining how frequently the hypothesis actually occurs).

when load is rising quickly and renewables are simultaneously ramping offline. The fatal flaw of Parson's analysis was in not rerunning the Real-Time results. Dr. Parsons failed to answer the critical question of whether the virtual transactions that were committing additional resources were lessening the frequency and severity of the shortage pricing events. Regardless, virtuals were committing additional generation in the Day-Ahead and making CAISO more reliable during scarcity events.

But There Are Flaws in the ISO/RTO Markets

While the Financial Marketers Coalition strongly supports the concept of the ISO/RTO markets, in practice, there are issues to be addressed. The primary issue faced by minority interests such as financial market participants, is the strength of entrenched utility interests in the stakeholder process, the resistance of those interests to new market entrants and the deference that the staff of the ISO/RTOs give to these incumbent interests. During the last Powering America hearing, Ranking Member Bobby Rush (D-IL) welcomed discussion on the market issues associated with RTOs beholden to incumbent utilities:

> As we will soon hear, Mr. Chairman, many consumer advocacy groups believe that the RTOs are too beholden to the utilities than they are trying to administrate. And consumers do not have a large enough seat at the table to make their voices heard. Many of these advocates argue that the whole process for reforming energy markets have become more and more complex, while at the same time consumer voices have been diluted to the point of being completely shut out. There also seems to be, a new consensus, Mr. Chairman, among today's witnesses, that FERC and DOE have become too tolerant of the RTOs' ability to shut out public interests, and participation, and policymakers must act to address this challenge.[14]

Ranking Member Rush's concerns are very accurate, but they extend past consumers to encompass all minority interests in the ISO/RTO stakeholder process, among them financial

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[14] Transcript of Powering America: Consumer-Oriented Perspectives on Improving the Nation's Electricity Markets at 3-4 (Oct. 7, 2017), *available at* http://docs.house.gov/meetings/IF/IF03/20171005/106470/HHRG-115-IF03-Transcript-20171005.pdf

market participants. Recent initiatives in the PJM stakeholder process to essentially eliminate the UTC product by imposing a double tax through uplift payments and reducing by over 90% the points at which such transactions may be placed, highlight these stakeholder process concerns. These proposals are currently pending at FERC, where we have strongly argued that FERC must act to protect financial trading and send a strong message to the ISO/RTO, its staff and stakeholders regarding voting and process irregularities.

Conclusion

In conclusion, the Financial Marketers Coalition greatly appreciates the opportunity to testify to the Subcommittee on the role and importance of financial trading in wholesale competitive electricity markets operated by the ISO/RTOs. We believe that the markets work, and should be allowed to continue working. We also believe that financial trading is a key element in maintaining competition, liquidity and good price formation in those markets. We do see areas for improvement and look forward to working with the Subcommittee, FERC and the ISO/RTOs on these issues.

Mr. UPTON. Thank you.

Next, we are joined by Eric Hildebrandt, director of Market Monitoring for the California ISO. Welcome.

STATEMENT OF ERIC HILDEBRANDT

Dr. HILDEBRANDT. Good morning, Congressman. Thank you for inviting me today. My name is Eric Hildebrandt, director of Market Monitoring at the California ISO. The Department of Market Monitoring serves as the independent market monitor for the California ISO. The Federal Energy Regulatory Commission requires each ISO to have an independent market monitor whose mission includes, quote, "the protection of consumers and market participants by the identification and reporting of market design flaws and market power abuses."

My testimony today highlights a major market design flaw that exists in all ISOs which is costing transmission ratepayers at least $400 billion per year. This flaw involves the auctioning by ISOs of financial instruments called financial transmission rights or FTRs. California calls these congestion revenue rights or CRRs.

Ratepayers of load-serving entities pay the full cost of the transmission system through transmission access charges and also higher prices when congestion occurs. All congestion revenues collected by ISOs should therefore be allocated back to transmission ratepayers. In fact, FTRs were initially developed as a way to fairly allocate congestion revenues back to the participants who pay for the transmission system.

All ISOs currently allocate FTRs to load-serving entities based on their projected use of the transmission system. We support continued use of FTRs in this way to provide load-serving entities with a hedge that offsets the congestion costs they may incur. However, we believe that all additional congestion revenues that remain after settlement of these allocated FTRs should also be refunded to transmission ratepayers.

Currently, however, after allocating FTRs to load-serving entities, ISOs then auction off additional FTRs. These FTRs are essentially price swaps. But unlike price swaps for other commodities, FTRs are not cleared and settled based on bids from willing buyers and sellers. Instead, ISOs auction off FTRs and then pay off these FTRs using congestion revenues that would otherwise be refunded to transmission ratepayers.

Unfortunately, the revenues collected from the auctioned FTRs consistently are much lower than what ISOs pay out. This makes FTRs highly profitable for financial entities, but these profits directly reduce congestion revenues refunded back to ratepayers. We estimate ISO ratepayers nationwide are losing at least $400 million per year from FTRs sold at auction. Almost all of these profits are going to purely financial entities and trading companies with a very small portion of FTRs purchased as potential hedges against congestion costs.

In California, ratepayers lost over $680 million since 2009 or about $75 million a year through the auction. Ratepayers receive only 52 cents in the auction for each dollar that the ISO pays out to these FTRs. This represents a profit of nearly a hundred percent for financial entities purchasing these FTRs.

In the PJM Interconnection, data indicated ratepayers have lost at least $1.2 billion in FTR auctions, or about $170 million per year. As a result, PJM's independent market monitor and the Organization of PJM States are calling for changes to PJM's FTR process to ensure all congestion revenues are refunded to ratepayers.

In New York, recent analysis by Stanford University shows that non-load-serving entities received FTR profits of over 900 million since 1999, or about $60 million per year. As explained in a 2014 expose in the New York Times, FTRs were originally designed to help protect electricity producers, utilities, and industries that need to buy power, but, quote, Wall Street banks and other investors have stepped in, siphoning off much of the money.

In the Midwest ISO, ratepayers have received less than 80 percent of day-ahead congestion rent since 2010. This represents a loss of at least a hundred million dollars per year from the FTR auction. If ISOs don't take action to address this issue, the FERC will need to take action to protect the Nation's transmission ratepayers.

Thank you again for the opportunity to be here today and I look forward to answering any questions you have on this issue.

[The prepared statement of Dr. Hildebrandt follows:]

Summary of Testimony of Eric Hildebrandt, PhD
Director, Department of Market Monitoring
California Independent System Operator Corporation

Ratepayers of load serving utilities pay for the full cost of the transmission system through Transmission Access Charges – and also through higher prices when congestion occurs. All congestion revenues collected by ISOs from use of the transmission system should therefore be allocated back to transmission ratepayers. However, all ISO's auction financial instruments commonly called Financial Transmission Rights ("FTRs"). Revenues collected from auctioned FTRs are consistently much lower that what the ISOs pay out to entities purchasing these FTRs. This directly reduces the congestion revenues that would otherwise be refunded back to transmission ratepayers.

Based on data reported by ISOs, we estimate transmission ratepayers nationwide are losing over $400 million per year from auctioned FTRs. Almost all profits from auctioned FTRs are going to purely financial entities and trading companies – with a very small portion of FTRs purchased by electric generators as potential hedges against congestion costs. ISOs do not need to auction FTRs for electricity suppliers to gain access to physical transmission or to hedge price risks associated with wholesale energy contracts and trading. If policy makers believe ISO's should facilitate financial hedging, ISO's should do this through a market for FTRs that is cleared and settled based on bids and offers from willing buyers and sellers. Transmission ratepayers should not be exposed to the losses and risks that they are currently suffering as a result of FTR auctions being run by ISOs.

Testimony of Eric Hildebrandt, Ph.D.
Director, Department of Market Monitoring
California Independent System Operator Corporation

Committee on Energy and Commerce
Subcommittee on Energy
United States House of Representatives
November 29, 2017

My name is Eric Hildebrandt. I am the Director of Market Monitoring at the California Independent System Operator (ISO). The Department of Market Monitoring serves as the independent market monitor for the California ISO. Under FERC regulations, each Commission-approved ISO must have an independent market monitor, whose mission includes "the protection of consumers and market participants by the identification and reporting of market design flaws and market power abuses."[1]

My testimony today focuses on a major market design flaw that exists in all FERC jurisdictional ISOs which is costing transmission ratepayers over $400 million each year. This flaw involves the auctioning of purely financial instruments most commonly called Financial Transmission Rights ("FTRs"). The California ISO calls these Congestion Revenue Rights (or "CRRs").

Ratepayers of load serving utilities pay for the full cost of the transmission system through Transmission Access Charges – and also through higher prices when congestion occurs. All congestion revenues collected by ISOs should therefore be allocated back to transmission ratepayers. In fact, FTRs were initially developed as a

[1] Final Rule, Order No. 719 (Issued October 17, 2008) §35.28 Part 35 3(i) (f) P.314. https://www.ferc.gov/whats-new/comm-meet/2008/101608/E-1.pdf

way to fairly allocate congestion revenues back to participants who pay for the transmission system.

All ISOs currently allocate FTRs to load serving entities based on their projected use of the transmission system. We support continued use of FTRs in this way as a means for providing load serving entities with a hedge that offsets congestion charges they incur. In addition, all of the additional congestion revenues that remain after settlement of these allocated FTRs should also be refunded to transmission ratepayers.

However, after allocating FTRs to load serving entities, all ISOs then auction off additional FTRs. These financial instruments are essentially *price swap* contracts. But unlike price swaps for other commodities, FTRs sold in the ISO auction are not cleared and settled based on bids from willing buyers and sellers. Instead, ISOs auction off FTRs -- and then paid off these FTRs using congestion revenues that would otherwise be refunded to transmission ratepayers.

Unfortunately, revenues that ISOs collect from auctioned FTRs are consistently much lower that what the ISOs pay out to entities purchasing these FTRs. This makes FTRs highly profitable for financial entities, but these profits directly reduce the congestion revenues that would otherwise be refunded back to transmission ratepayers.

Based on data reported by ISOs, we estimate transmission ratepayers nationwide are losing over $400 million per year from FTRs sold at auction in various ISOs. Almost all of these profits are going to purely financial entities and trading companies – with a very small portion of FTRs purchased by electric generators as potential hedges against congestion costs.

In the California ISO, ratepayers have lost over $680 million since 2009 – or about $75 million per year. Transmission ratepayers receive only 52 cents in auction revenues for each dollar the ISO pays out to these FTRs. That represents a profit of nearly 100 percent for entities purchasing these FTRs.

In the PJM Interconnection, data indicate that transmission ratepayers have lost about $1.2 billion in FTR auctions to financial entities since 2011 – or about $170 million per year.[2] As a result, PJM's independent market monitor and the Organization of PJM States have called for changes to PJM's FTR process to ensure all congestion revenues are returned to load serving entities.[3]

In the New York ISO, recent analysis at Stanford University shows that non-load serving entities received FTR profits over $900 million since 1999 – or about $60 million per year.[4] As explained in a 2014 expose in the *New York Times,* FTRs were originally designed to help "protect the electricity producers, utilities and industries that need to buy power" by helping them "hedge against sharp price swings .... but Wall Street

[2] Monitoring Analytics, 2016 *State of the Market Report for PJM* p. 553: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec13.pdf
Monitoring Analytics, 2017 *Quarterly State of the Market Report for PJM: January through December* p. 599: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017q3-som-pjm-sec13.pdf

[3] Organization of PJM States, Inc (OPSI), *OPSI Resolution 2016-4 Concerning Financial Transmission Rights*, Approved August 18, 2016. https://www.pjm.com/~/media/about-pjm/who-we-are/public-disclosures/20160826-opsi-letter-and-resolution-regarding-ftr-construct.ashx

[4] Leslie, Gordon, "Why do transmission congestion contract auctions cost ratepayers money? Evidence from New York," November 14, 2017, pp. 23-24, downloaded 11/17/2017: http://www.web.stanford.edu/~gwleslie/index_new_files/Leslie_JMP20171114.pdf.

banks and other investors have stepped in, siphoning off much of the money," according to the *Times*.[5]

In the Midwest ISO, transmission ratepayers have received less than 80 percent of day-ahead congestion rent, representing a loss of at least $100 million per year from the MISO's FTR auction. [6]

ISOs do not need to auction FTRs for generation owners or energy traders to gain access to physical transmission or to hedge price risks associated with wholesale energy contracts and trading. As with other commodities, market participants and financial entities are free to develop and trade price swap contracts. In fact, this type of free market – with trades between willing buyers and sellers – is what is needed to price such price swaps most efficiently and fairly.

If policy makers believe it is beneficial to wholesale electricity markets and consumers for ISO's to facilitate such financial price swaps, then ISO's should do this through a market for FTRs that is cleared and settled based on bids and offers from willing buyers and sellers.

Transmission ratepayers should not be exposed to the losses and risks that they are currently suffering as a result of FTR auctions being run by ISOs. If ISOs do not

[5] "Traders Profit as Power Grid is Overworked" *The New York Times* August 14, 2014: https://www.nytimes.com/2014/08/15/business/energy-environment/traders-profit-as-power-grid-is-overworked.html

[6] *Problems in the performance and design of the congestion revenue right auction*, Department of Market Monitoring, California Independent System Operator, November 27, 2017, pp. 18-19. http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

take action to address this issue, FERC will need to take action to protect the nation's transmission ratepayers.

Additional details of our analysis, along with a detailed discussion of the fundamental economic flaws underlying the auctioning of FTRs, are provided in an attached report by the California ISO Department of Market Monitoring.[7] Another report posted on our website provides a discussion of market-based options through which energy generators, traders and financial entities can buy and sell financial instruments that allow hedging of congestion costs.[8]

Thank you for the opportunity to appear before you today. I look forward to answering your questions on this important issue.

[7] *Problems in the performance and design of the congestion revenue right auction*, Department of Market Monitoring, California Independent System Operator, November 27, 2017. http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

[8] *Market alternatives to the congestion revenue rights auction,* Department of Market Monitoring, California Independent System Operator, November 27, 2017. http://www.caiso.com/Documents/Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

California ISO

California Independent System Operator Corporation

California ISO

Problems in the performance and design of the congestion revenue right auction

November 27, 2017

Department of Market Monitoring

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Summary

In markets based on locational marginal pricing, binding transmission constraints cause locational prices to differ. Prices are higher in areas where transmission limits constrain the ability of lower cost generation to meet demand and higher cost generation must be used. Prices are lower in areas where transmission limits constrain the market from using otherwise available lower cost generation. These price differences cause the total amount paid by buyers to exceed the amount paid to suppliers over the entire system. This creates a source of revenue known as *congestion rent* since it results from higher prices reflecting congestion on transmission constraints.

Most congestion rents are allocated back to transmission ratepayers because they pay for most of the transmission system through the transmission access charge (TAC). The TAC is collected based on each participant's demand (i.e. load or exports). The TAC is set at a fixed rate ($/MWh) designed to cover the full capital costs and rate of return for transmission assets. Any revenues collected above the level required to cover these transmission costs, such as congestion rent, should therefore be refunded to the TAC ratepayers.

Allocated CRRs are part of a system that distributes congestion rent to load serving entities on behalf of retail ratepayers and to other TAC ratepayers. This paper does not concern the congestion rent allocation or propose any changes to the current CRR allocation process.

Auctioned CRRs, on the other hand, are purely financial instruments that obligate the ISO's transmission ratepayers to pay entities purchasing these CRRs the difference in day-ahead market prices between two locations. An auctioned CRR is a forward price swap. Payments in the auction are exchanged for payments based on differences in day-ahead market prices.

California ISO transmission ratepayers lost over $680 million in the congestion revenue right (CRR) auction from 2009 through 2017. For every dollar ratepayers paid to entities purchasing CRRs in the auction, ratepayers received only 52 cents in auction revenues. This consistent underpricing of CRRs calls into question a fundamental assumption of the CRR auction design that competition will drive auction prices to equal the CRR's expected value.

As described in this paper, the CRR auction differs from a competitive market—and other forward financial markets—in several ways. These differences create opportunities for purely financial entities to purchase CRRs at prices systematically lower than the payments that ratepayers are obligated to pay the auction participants. DMM has recommended that the ISO takes steps to eliminate the current framework by which the ISO auctions CRRs, and consider if the ISO should instead play a role in facilitating trading of CRRs or similar price swaps between willing buyers and sellers through a market based only on bids and offers.

Auctioned CRRs are not needed for transmission access or to ship power between nodes. An LMP market is a centrally cleared market. Power is sold or bought through the central market at the market price. Market participants do not ship power from one location to another. The LMP at each location is the appropriate market price for that location. A CRR is not needed to ship power between locations because power is not shipped between locations.

A CRR is not a day-ahead market transmission right. All day-ahead market bidders have access to the transmission system regardless of whether or not they hold a CRR. Instead, an auctioned CRR is simply a forward contract. This forward contract allows auction participants to hedge financial exposure to–or speculate on—uncertain day-ahead price differences between two locations.

The demand for a financial hedge against day-ahead market locational price differences primarily comes from forward contracts that settle on pre-agreed upon reference power prices in the spot market. This forward contracting takes place outside the ISO markets. A supplier may sell a forward power contract at a location different than its generator's location. When this occurs, the day-ahead price on which the forward contract settles will be different than the day-ahead price the generator receives for selling power into the day-ahead market. Different settlement locations cause the supplier to face an uncertain day-ahead price difference that will not be hedged by the forward power contract. To hedge this uncertainty, a supplier may be willing to buy a forward contract for the difference between the day-ahead prices at the two locations.

Financial forward contracts on locational price differences can be purchased in the CRR auction. Unlike most other forward contract markets, the CRR auction allows participants to take positions without a counterparty offering to take the opposite position. Market participants can buy forward contracts in the CRR auction without trading with a willing seller. This is because the auction makes the ISO's transmission ratepayers the counterparty to contracts bought from the CRR auction without being an explicit willing seller.

CRR forward contracts are essentially price swaps offered for sale in the auction at offer prices of $0 by the ISO on behalf transmission ratepayers. To avoid being a counterparty to the forward contracts offered under the current CRR auction design, ratepayers would need to participate in the auction to buy contracts from themselves. This is the opposite of most other forward markets where sellers must willingly offer to enter a forward contract.

While ratepayers may want to buy CRRs to avoid forward contract obligations, they cannot readily buy them. Technical, economic and regulatory hurdles restrict ratepayer participation in the auction. Ratepayers cannot easily avoid being a counterparty to the forward contracts they did not offer to enter. An auction participant can therefore buy a CRR from ratepayers for a price at which ratepayers would not willingly sell.

The CRR auction also differs from other forward markets, and competitive markets generally, in another significant way. Competitive markets trade a well-defined product or property right. For example, a forward contract for a bushel of wheat is defined as a bushel of wheat in both the forward and spot markets. A natural gas forward basis contract between Henry Hub and Chicago is defined as the price difference between Henry Hub and Chicago in both the forward and spot markets. A CRR is not consistently defined between the auction and day-ahead market.

CRRs are auctioned as a bundle of forward contracts on specific transmission constraints. However, CRRs are not settled as the same bundle of forward contracts at day-ahead market prices. Instead, the CRRs are settled at the day-ahead market locational price differences between two locations. A CRR will only be consistently defined if the bundle in the auction is the same as the implied bundle from the day-ahead market price differences. When the transmission models are different in the auction and day-ahead market, the bundles will not be the same. The CRR will be a different product when bought than when settled at day-ahead market prices.

CRRs are unlikely to be consistently defined because the CRR auction relies on a single estimated network model to estimate a series of different hourly day-ahead network models that are ultimately used in the market over the entire settlement month or quarter. This settlement is like allowing auction participants to purchase premium gasoline at prices for regular gasoline with ratepayers making up the difference. Profit maximizing auction participants would bid to obtain CRRs that the auction models as being of a lower (regular) value but which they anticipate to be a higher value (premium) product.

The peculiarities and complexities of the CRR 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.

There is no clear rationale for the ISO to offer forward price swaps. Market participants can freely contract and trade forward price swaps outside the ISO. If the ISO continues to facilitate the trading of forward price swaps, the auction design should be changed so that only willing counterparties will enter forward contract obligations.

1 CRRs are financial forward contracts

Ratepayers pay for and own most congestion rent

Nodal markets are designed to promote efficient use of the scarce transmission system. The transmission system both facilitates and limits the ability to reliably trade energy. The limited transmission available in the day-ahead market constrains the choice of optimal energy schedules. This creates locational price differences which in turn creates congestion rent.[1]

Most congestion rents are allocated back to transmission ratepayers because they pay for most of the transmission system through the transmission access charge (TAC.[2] Ratepayers pay for the capital costs and rate of return on transmission assets through TAC that is imposed on all load schedules. Any revenues that these transmission assets earn in excess of the rate of return included in the TAC should therefore be credited or refunded to transmission the ratepayers.

The ISO currently distributes congestion rent to the TAC ratepayers through an allocation process that includes the CRR allocation process. This allocation process is designed so that congestion rents are refunded back to different groups of transmission ratepayers in approximately the same proportion as these groups pay congestion. This paper does not concern the congestion rent allocation. Instead the focus of this paper is on the CRR auction.

Network models define the transmission right products

As described in the following subsections, auctioned CRRs are not rights to physical transmission, nor are auctioned CRRs even the rights to day-ahead market congestion rents. A CRR is a forward contract that is settled base on the difference in day-ahead market prices between two locations. Although a CRR settles on the day-ahead market congestion price differences, the ISO auctions CRRs as bundles of forward contracts to specific transmission constraints. Using the term *congestion rights* to refer to CRRs is inaccurate and misleading. In practice, congestions rents collected can be higher or lower than CRR payments, and payment of CRRS is made independent of congestion rents actually collected. Therefore, for the rest of this paper, we refer to CRRs as *forward contracts*.

The CRR auction clears by maximizing total bid value constrained by the transmission network model. Forward contracts sold in the auction are defined by a network model, which includes specific nodes (locations), transmission constraints and shift factors. A *shift factor* describes how many forward contracts on a constraint are bought or sold from a one megawatt injection at a specific location. A CRR bids as an injection at a source location balanced by a withdrawal at a sink location. The forward contracts a CRR buys or sells on a particular constraint is the source shift factor minus the sink shift factor multiplied by the cleared CRR megawatts. The auction price for each increment of forward contract for that one constraint is the CRR auction's shadow price on the constraint.

[1] A good analogy is that transmission use is an externality of scheduling power and the transmission price is an externality tax, as explained on pg. 26 of Oren, Shmuel S., Pablo T. Spiller, Pravin Varaiya, and Felix Wu. 1995. "Nodal Prices and Transmission Rights: A Critical Appraisal." *Electricity Journal*,p. 32: http://www.ieor.berkeley.edu/~oren/pubs/nodal.pdf.

[2] Exceptions to this are rights owned by merchant transmission and long-term rights holders. However, these are very minor in the CAISO system.

If a CRR's net shift factor (source shift factor minus sink shift factor) is positive, the CRR purchases forward contracts for the constraint's price. If a CRR's net shift factor is negative, the CRR sells forward contracts. The total forward contracts purchased by participants bidding in the auction do not need to equal the forward contracts sold by participants bidding into the auction. Instead, the forward contracts bought minus the forward contracts sold must be less than the forward contracts made available in the auction through each constraint's transmission limit.

Equation 1 shows a CRR auction transmission constraint called *k*. Individual CRRs are indexed by *i*.

Equation 1. CRR market constraints define forward contracts auctioned

$$\sum_i MW_i^{CRR}(ShiftFactor_{i,source}^k - ShiftFactor_{i,sink}^k) \leq Limit^k$$

$$Contracts\ Bought\ -\ Contracts\ Sold\ \leq\ Contracts\ offered\ by\ auction$$

Auction participants can buy more forward contracts than are sold by other participants bidding in the CRR auction. More forward contracts can be bought than sold because the ISO makes forward contracts available through its auction's transmission model. The ISO sells these forward contracts on behalf of transmission ratepayers. The CRR buyers pay ratepayers the auction revenues. The ratepayers then pay the buyers the day-ahead prices for these forward contracts. The ISO offers forward contracts on the ratepayers' behalf (through the limits on transmission elements in the CRR auction) with zero offer prices.

CRRs are considered *revenue adequate* when revenues from congestion rents are greater than or equal to the payments to CRRs. CRRs will be revenue adequate if the transmission limits and network models (shift factors) are the same[3] in both the auction and day-ahead market.[4] When the auction limits or network models are different, the CRRs may not be revenue adequate.

Revenue adequacy is not a concern in forward markets for other commodities.[5] In forward markets for other commodities buyers and sellers are matched and revenue adequacy is assured. Revenue adequacy does not matter for CRRs either. Revenue adequacy does not matter because the CRR auction actually does match buyers and sellers. Ratepayers will always be the counterparties to contracts not matched between the buyers and willing sellers who bid into the auction.

As discussed in detail in the next three sub-sections, CRRs can be better understood by interpreting CRRs from the perspective of the transactions between the buyers and sellers of CRRs, rather than from the perspective of revenue adequacy. The underlying transactions are the exchange of a fixed payment in the auction for floating payments at the uncertain day-ahead market prices. The transactions that matter to ratepayers are the auction revenues they receive compared to the payments they are obligated to make to CRR holders.

[3] More precisely, the difference between shift factors has to be the same between all locations.

[4] Hogan, William W. 1992. "Contract Networks for Electric Power Transmission." *Journal of Regulatory Economics*. See the version at: http://www.hks.harvard.edu/fs/whogan/acnetref.pdf.

[5] This assumes away default risk, which is different than the revenue adequacy referred to here.

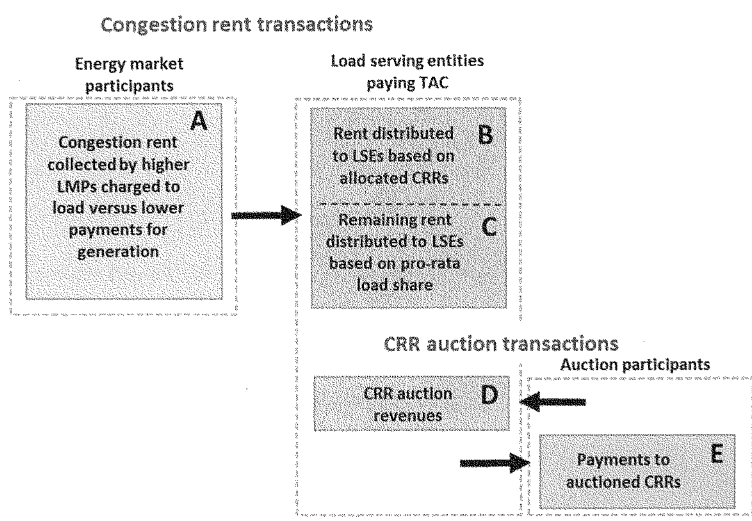
Accounting for ratepayer gains or losses from CRRs sold in the auction

The congestion revenue rights balancing account is a settlement mechanism. This settlement mechanism ensures that the final *net* payments and charges to the day-ahead market and to CRR auction participants are correct. The CRR balancing account processes two underlying transaction types. To understand the actual day-ahead market and CRR auction trades, we should consider the underlying transactions, rather than the net sum of the CRR balancing account.

Figure 1 shows the two transaction types from the ratepayer's perspective. In the first type of transaction (box A), entities with energy schedules clearing the day-ahead market pay congestion rents. As discussed, transmission ratepayers should receive these congestion rents since they have paid for the transmission system through the TAC. Therefore, the ISO distributes some of the congestion rents to transmission ratepayers by CRRS allocated to load serving entities (box B). Any congestion rents remaining after the allocation process are distributed to participants who pay the TAC based on their *pro-rata* share of demand schedules, i.e. loads and exports (box C). Load serving entities, who are the largest transmission ratepayers, then pass the congestion rents back to transmission ratepayers.

In the second type of transaction (shown in boxes D and E), CRR auction participants and ratepayers (who do not participate in the auction) trade financial forward contracts through auctioned CRRs. Auction participants pay the forward price (the auction price) to ratepayers (box D). In exchange, ratepayers take on the obligation to pay the spot price (the difference between the source and sink day-ahead market prices) to auction participants (box E). The exchange of forward CRR auction revenues for spot market payments to auctioned CRRs at day-ahead market prices is the ratepayers' overall net forward contract trade.

Figure 1. Different transaction types settled through the CRR balancing account



If no CRRs were sold at auction, all remaining congestion revenues after payments made to allocated CRRs would be refunded to ratepayers of load serving entities who pay the TAC based on their *pro-rata* share of demand (box C). Thus, whenever auction revenues are less than payments made by the ISO to CRRs, the difference is a direct loss for transmission ratepayers.

Congestion revenue rights are not actually rights to congestion rents

When the CRR auction transmission model and day-ahead market transmission model are the same, we can view a CRR as a forward contract, a point-to-point transmission right, or a right to a share of congestion rent.[6] All three views are financially equivalent.

However, the CRR auction and day-ahead market transmission models are inevitably different. When the models are different, paying CRRs the day-ahead market settlement price is not the same as paying a share of the congestion rent. For example, if 100 MWs of transmission is sold to entities with schedules clearing the day-ahead market, the ISO cannot pay CRRs for rights to 115 megawatts worth of congestion rent. The CRRs clearly do not represent the rights to the congestion rents. Instead, ratepayers receive the congestion rents for the 100 megawatts of transmission sold to day-ahead market schedules (see Transaction 1 in Figure 1). Separately, ratepayers must pay day-ahead market locational price differences to settle the 115 megawatts of CRR forward contracts that the ISO auctioned off on the ratepayers' behalf (see Transaction 2 in Figure 1).

Even if the transmission models are the same, the CRR contracts sold for a constraint can be greater than the transmission limit because auction participants can sell additional forward contracts. If the constraint limit is 10 MWs and some participants sell an additional 50 MWs of forward contracts through CRR bids, a total of 60 MWs of forward contracts can be purchased by other CRR auction participants. 60 MWs of rights to congestion rent do not exist. The ISO does not arbitrarily decide that a particular 10 MWs of CRRs is rights to congestion while the other 50 are something else. Instead, all 60 MWs are forward contract purchases with 50 MWs sold by parties bidding into the auction and 10 MWs sold on behalf of transmission ratepayers.

CRR profitability is the relevant measure of CRR auction performance

CRR revenue inadequacy has traditionally received a lot of attention. Concerns over whether there will be sufficient congestion rent to pay the CRRs are rooted in the prevalent and incorrect view that CRRs are rights to the day-ahead market congestion rent. But once we recognize that CRRs are simply forward contracts, and not rights to congestion rent, it becomes clearer that focusing on revenue adequacy incorrectly frames the problem as a need for the ISO to make the "correct" amount of forward contracts available in the auction on behalf of ratepayers.

The relevant question for ratepayers is *not* how total payments to CRRs compare to total day-ahead congestion rent (i.e. it is not a question of revenue adequacy). The relevant question for ratepayers is how the payments ratepayers are obligated to make to auctioned CRR holders compare to the CRR auction revenues ratepayers receive. If ratepayers pay auctioned CRR holders more than the auction revenues ratepayers receive, then ratepayers will lose money on their CRR forward contracts.

[6] Harvey, Scott M, William W Hogan, and Susan L Pope. 1997. *Transmission Capacity Reservations and Transmission Congestion Contracts.* Cambridge, MA: Harvard University, p. 62 of the version at: http://www.hks.harvard.edu/fs/whogan/tccoptr3.pdf.

The auction revenues ratepayers receive depends on how well the CRR auction prices CRRs. A well-functioning competitive auction would price CRRs near their expected value. The CRR auction revenues ratepayers receive would roughly equal the ratepayers' expected payments to non-LSE CRR holders. The CRRs purchased from ratepayers by non-LSE auction participants would not be highly profitable. If the CRR auction is not a well-functioning competitive market, non-LSE auction participants can consistently profit from ratepayers' losses without driving up CRR auction prices.

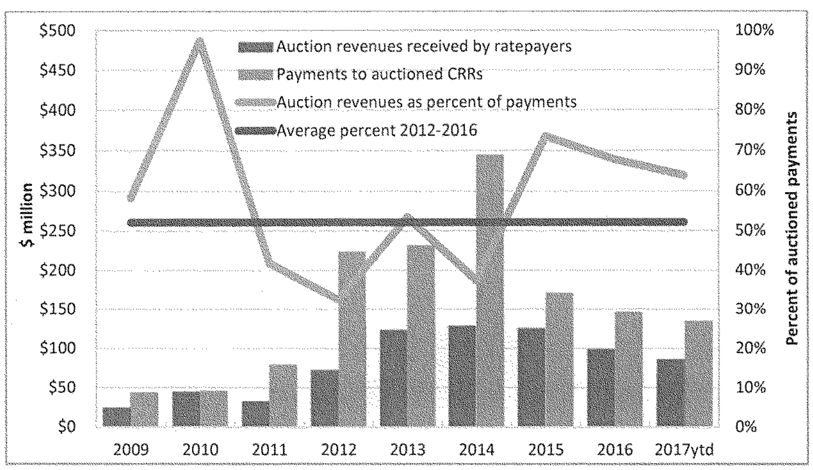
2 CRR auction results

The section provides analysis of the ISO's CRR auction since 2009. The section also provides a review of analysis and studies that have been performed for other ISO's. This analysis shows that auction revenues have been systematically much lower than CRR payments made to non-load serving entities. These results are not consistent with a well-functioning competitive market. Data from other ISO's indicate that these trends occur in other ISO's as well.

CRRs are auctioned for only half the value of CRR payments

As shown in Figure 2, ratepayers have consistently lost money in the CRR auction each year since the ISO's LMP market began in 2009. Ratepayers have lost over $680 million from the CRR auction from 2009 through 2017, or an average of $75 million per year. Ratepayers paid over $1.4 billion to non-LSE CRR holders but received only $742 million in auction revenues. For every dollar paid to non-LSE CRR holders, ratepayers received just 52 cents. This represents more than a 90 percent annual rate of return for non-LSE entities purchasing CRRs in the auction. This clearly reflects a systematic bias and distortion in the CRR auction.

Figure 2. Auction revenues and auctioned CRR payments excluding LSEs



As shown in Table 1, most profits from CRRS purchased in the auction go to financial entities that do not operate or schedule physical generation assets in the ISO system – and do not purchase CRRS to hedge power contracts. Since 2009, non-LSEs and non-physical generation entities (financial entities and marketers) received about $598 million in profits from the CRR auction, paying 52 cents per dollar received – representing a profit of almost 100 percent. Physical generators received $86 in profits paying 45 cents per dollar.

Table 1. CRR auction profits ($ millions) – Physical generators

Year	Auction Revenues	CRR Payments	Profits
2009	$2	$2	$0
2010	$0	$1	$1
2011	($1)	$3	$4
2012	$9	$25	$16
2013	$14	$31	$16
2014	$14	$48	$34
2015	$17	$24	$7
2016	$9	$14	$5
2017*	$7	$11	$3
Total	**$71**	**$157**	**$86**

*2017 is year-to-date through October 31.

Table 2. CRR auction profits ($ millions) – Financial traders and marketers (excludes load serving entities and physical generators)

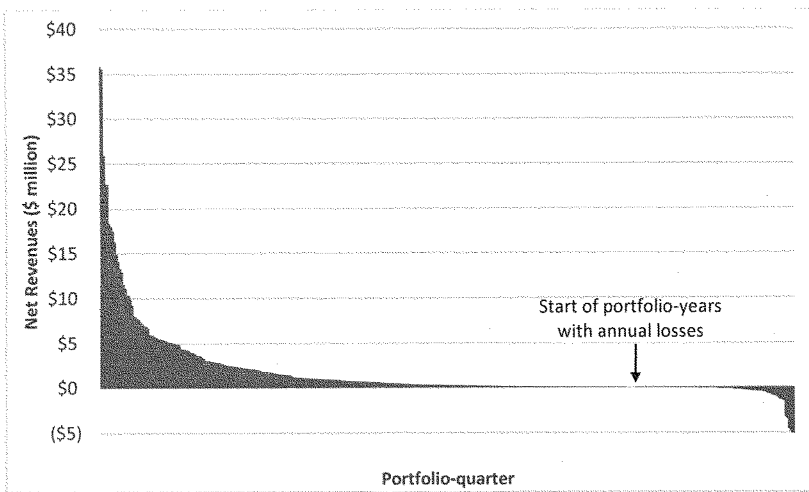
Year	Auction Revenues	CRR Payments	Profits
2009	$24	$43	$19
2010	$45	$46	$0
2011	$35	$78	$43
2012	$64	$200	$136
2013	$110	$201	$91
2014	$115	$297	$182
2015	$109	$148	$39
2016	$91	$133	$43
2017*	$79	$125	$46
Total	**$671**	**$1,269**	**$598**

*2017 is year-to-date through October 31.

Figure 3 provides a more detailed analysis of how CRRs have been consistently profitable over time for virtually all non-TAC ratepayer (non-LSE) CRR auction participants. Figure 3 shows the distribution of total annual profits and losses for all annual portfolios of CRRs purchased by non-LSEs over the 2009 through Q3 2017 period. These data illustrate that the portfolios of CRRs purchased by different non-LSEs in the auction were systematically profitable and extremely skewed, with very limited risk of potential losses.

Over the 2009 through Q3 2017 period shown in Figure 3, non-LSE portfolios that were profitable were paid about $728 million dollars. Non-LSE portfolios that were not profitable lost only about $50 million. The losses were about 7% the amount of gains. This is not indicative of a well-functioning market. The $677 million difference in profitable versus unprofitable CRR portfolios purchased in the auction was paid from revenue that would otherwise have been refunded to transmission ratepayers to partially offset TAC payments charged to load serving entities.

Figure 3. Annual profits on auctioned CRRs by entity (excluding LSEs) 2009-Q3, 2017



Figures 4 through 6 summarizes a more detailed analysis of how systematically profitable portfolios of CRRs purchased in the auction have been for different types on non-LSEs. These figures compare the amount paid by individual participants for portfolios of monthly and seasonal CRRs each quarter to the revenues received for these portfolios. Observations below the 45 degree line are quarterly CRR portfolios that were profitable. Observations above the 45 degree line are quarterly portfolios that were unprofitable.[7]

[7] These charts also show CRR portfolio data from Q1 2014 through Q2 2017 calculated on a quarterly basis corresponding to the term of seasonal CRRs (rather than on a monthly basis).

Figure 4. All non-Load serving entities' quarterly auction revenues versus CRR payments by portfolio (2014-Q2 2017)

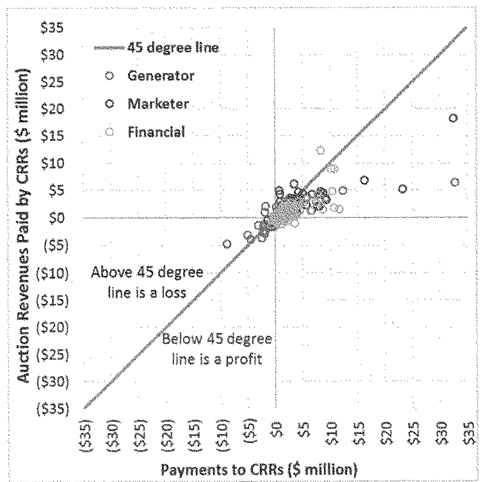


Figure 5. Financial entities' quarterly auction revenues versus CRR payments by portfolio, 2014 to Q2 2017 (axes truncated at $10 million)

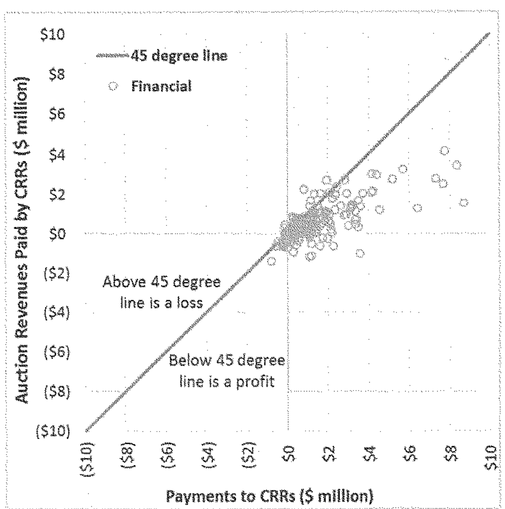


Figure 6. Marketers' quarterly auction revenues versus CRR payments by portfolio (2014 to Q2 2017 - axes truncated at $10 million)

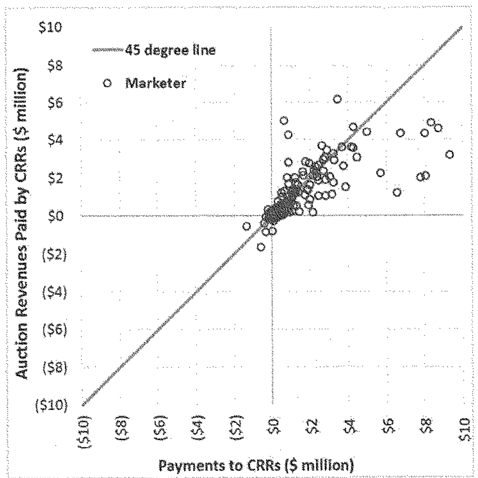
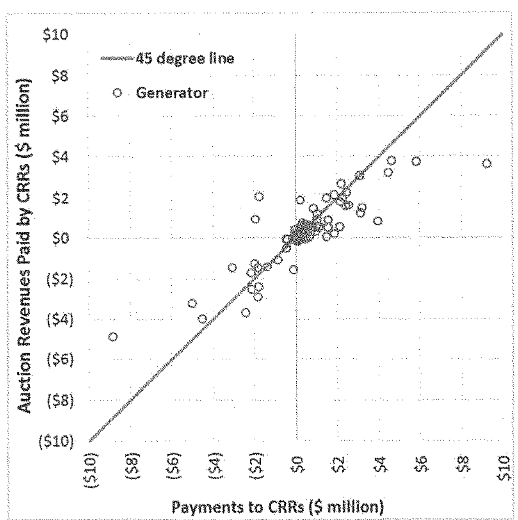


Figure 7. Generators' quarterly auction revenues versus CRR payments by portfolio, 2014-Q2 2017 (axes truncated at $10 million)



The risk and time value of money associated with CRRS does not explain abnormally high profits

Auction participants may be risk adverse. Risk aversion may cause the CRR auction prices to not equal the expected day-ahead payments. Auction participants may be increasing or decreasing their risk by procuring a CRR. Participants increasing their risk would be willing to pay less than the expected value. Participants decreasing their risk would be willing to pay more than the expected value as an *insurance premium*. Therefore we cannot presume that risk aversion will decrease or increase auction prices relative to the expected value.

This analysis does not discount the auction revenue and CRR payment flows for the time value of money. However, most of the monthly CRR payments occur less than a month after purchase. Only the payments to annual CRRs in late November and December occur more than a year after the CRRs are purchased. Given the short time periods, discounting the cash flows would not appreciably affect the values. The effects of risk aversion and the time value of money cannot account for pricing CRR's sold in the auction at only 53 cents for each dollar of congestion payments.

Ratepayers losses occur from CRR/FTR auctions in other ISOs/RTOs

The California ISO is not the only ISO/RTO where transmission ratepayers have been losing money in auctions for Financial Transmission Rights (the term for CRRs in these markets). [8] Data reported by different ISOs/RTOs is not always reported in a manner that clearly shows the impact of these auctions on transmission ratepayers. However, there are clear indications FTR auctions are highly profitable for the auction participants in multiple markets. Based on DMM's review, auctions clearly result in losses of several hundred millions dollars per year nationwide. A 2017 analysis at Stanford University estimates that losses to ratepayers total about $600 million per year in the countries four main ISOs. [9]

PJM

In the PJM Interconnection (PJM), data reported by PJM's Independent Market Monitor indicate that transmission ratepayers have lost over $1.18 billion in FTR auctions from 2011 to September 2017. Financial entities have received about $170 million per year in FTR profits (see Table 3).[10] As noted by PJM's Independent Market Monitor:

> In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs to pay back to load the difference between the total load payments and the total generation revenues, which equals total congestion revenues.

[8] CRRs in other ISOs/RTOs are also known as financial transmission rights (FTRs), transmission congestion contracts (TCCs), and transmission congestion rights (TCRs).

[9] "Traders Profit as Power Grid is Overworked" *The New York Times* August 14, 2014: https://www.nytimes.com/2014/08/15/business/energy-environment/traders-profit-as-power-grid-is-overworked.html

[10] Monitoring Analytics, 2016 *State of the Market Report for PJM* p. 553: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec13.pdf
Monitoring Analytics, 2017 *Quarterly State of the Market Report for PJM: January through December* p. 599: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2017/2017q3-som-pjm-sec13.pdf

PJM's Market Monitor has recommended changes to PJM's FTR process to ensure all congestion revenues are returned to load serving entities, noting that:

> The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues.

In 2016, the Organization of PJM States (OPSI) passed a resolution citing the PJM Market Monitors findings and recommendations calling upon PJM to propose a redesign of the PJM's FTR market "that will ensure that all congestion revenues are returned to consumers." [11] As noted in the OPSI resolution, "[c]onsumers pay for all congestion in the system, so anything short of the prospect for realizing a full return of those congestion revenues [to consumers] would indicate a failure in achieving the objective of the ARR/FTR construct."

Table 3. PJM financial entity FTR auction profits ($ millions)

Year	Financial Entity Profits
2011	$126
2012	$79
2013	$177
2014	$544
2015	$182
2016	$48
2017*	$34
Total	**$1,190**

*2017 ytd thru September.

NYISO

In 2014 the *New York Times* reported on the very large FTR auction profits in the New York ISO (NYSO).[12] As explained in the Times article, FTRs were originally designed to help "protect the electricity producers, utilities and industries that need to buy power," by helping them "hedge against sharp price swings caused by competition as well as the weather, plant failures or equipment problems." Those lower costs reduce consumers' bills, "but Wall Street banks and other investors have stepped in, siphoning off much of the money".

The New York Times article provides valuable insights into the barriers to competition in what it calls a "murky corner" of the energy market.

> Like top Wall Street banks, DC Energy [a major financial trader of FTRs] stocks its trading desk with graduates of elite universities. Most have backgrounds in science and engineering — a doctorate in chemical physics from Harvard, for example, or a master's degree in artificial intelligence from

[11] Organization of PJM States, Inc (OPSI), OPSI Resolution 2016-4 Concerning Financial Transmission Rights, Approved August 18, 2016. https://www.pjm.com/~/media/about-pjm/who-we-are/public-disclosures/20160826-opsi-letter-and-resolution-regarding-ftr-construct.ashx

[12] "Traders Profit as Power Grid is Overworked" *The New York Times* August 14, 2014: https://www.nytimes.com/2014/08/15/business/energy-environment/traders-profit-as-power-grid-is-overworked.html

Stanford — rather than in finance. Their job is to develop computer-driven trading models to predict what will happen to electricity prices in different parts of the nation.

As explained in the *New York Times*:

> ... in places like upstate New York or Long Island, the market is so small, and the participants for certain contracts so few, that knowledgeable traders can collect rich rewards. Frank A. Wolak, an economics professor at Stanford who studies commodities, said the congestion markets created perverse incentives because profits rise when grid congestion becomes worse. "If traders are making money, then consumers are paying more," Mr. Wolak said. "The money that these guys are making has to come from somewhere."

A recent research paper from Stanford University estimates that that in the New York ISO non-retail (non-LSE) entities received FTR profits totaling $938 million over the 1999-2016 period, almost $60 million per year.[13] As noted in this research:

> ... these derivatives have proven controversial because financial traders have consistently earned trading profits of $600m a year from holding these derivatives across the four largest U.S. electricity markets. These products are typically issued via regular auctions, with payouts of the issued derivatives funded by ratepayers, who in turn receive the auction revenues ... financial traders typically purchase many derivatives in small quantities between locations that physical firms do not tend to buy. Financial traders earn profits when they are the first to buy a previously illiquid product, where they effectively receive a transfer from ratepayers for this service.[14]

MISO

In the Midcontinent ISO (MISO) for the 2010-2011 through 2016-2017 planning periods, on average only about 80% of the day-ahead market congestion rent was received by transmission ratepayers.[15] As explained in earlier DMM reports, this implies that transmission ratepayer losses in the FTR auction were equal to about 20% of day-ahead congestion rents for the period.[16] Day-ahead congestion rent averaged about $790 million from 2011 through 2016.[17] This data indicates that transmission ratepayers in MISO have consistently suffered large losses from the FTR auctions, between $100 million and $200 million per year.

[13] Leslie, Gordon "Why do transmission congestion contract auctions cost ratepayers money? Evidence from New York" November 14, 2017, pp23-24, downloaded 11/17/2017: http://www.web.stanford.edu/~gwleslie/index_new_files/Leslie_JMP20171114.pdf.

[14] Ibid, p.1

[15] Midcontinent ISO *ARR/FTR Transmission Customer Metric May 11, 2017*: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2017/20170511/20170511%20MSC%20Item%20XX%20ARR%20FTR%20Transmission%20Customer%20Metric%20April%202017%20Update.pdf

[16] Department of Market Monitoring *Shortcomings in the Congestion Revenue Right Auction Design* p.6: https://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf

[17] MISO day-ahead congestion rent data from Potomac Economics *2016 State of the Market Report for the MISO Electricity Market* p.50; Potomac Economics *2014 State of the Market Report for the MISO Electricity Market* p.52; Potomac Economics *2012 State of the Market Report for the MISO Electricity Market* p.46. Reports available at: https://www.misoenergy.org/MARKETSOPERATIONS/INDEPENDENTMARKETMONITOR/Pages/IndependentMarketMonitor.aspx

Table 4 shows the percent of day-ahead market congestion rent received by MISO ratepayers across the planning years since 2010. Table 4 also shows the annual day-ahead congestion rent by calendar year. We estimate losses to ratepayers from the auction multiplying the percentage of day-ahead congestion rent that was *not* returned to ratepayers each year by the reported congestion rent for that year.

The planning period and calendar years used by the MISO are not align. Therefore, the range of auction losses is estimated first by multiplying the percentage of day-ahead congestion rent that was not returned to ratepayers by the congestion rent where the start year of the planning period and calendar year are the same. We also estimated auction losses based on congestion rents where the end year of planning period and calendar year are the same. These two approaches indicate a range of losses to MISO transmission ratepayers from FTRs sold in the auction of $165 million to $207 million.

Table 4. MISO percent of day-ahead market congestion rent received by ratepayers and estimated potential range of ratepayer FTR auction losses ($ millions)

Planning Period	Percent of DAM Rent Returned	Calendar Year	Annual DAM Rent	Estimated Auction Losses	
				Start Year Percent	End Year Percent
06/10 - 05/11	72%	2010	$498	$139	
06/11 - 05/12	75%	2011	$503	$126	$141
06/12 - 05/13	79%	2012	$778	$163	$194
06/13 - 05/14	64%	2013	$842	$303	$177
06/14 - 05/15	89%	2014	$1,444	$159	$520
06/15 - 05/16	83%	2015	$751	$128	$83
06/16 - 04/17	81%	2016	$737	$140	$125
Average	**78%**		**$793**	**$165**	**$207**

3 Market barriers and flaws in CRR auction design

This section explains several factors that are likely to help explain the very poor performance of the CRR auction from the perspective of ratepayers. These include:

- CRRs are not consistently defined products in both the auction and day-ahead market.
- CRR auction participants can profit from better information on difference in the way CRRs are defined in the auction versus the day-ahead market – without increasing efficiency or adding any value to ratepayers or other market participants.
- Ratepayers face significant limitations to bidding in auctions
- Buyers do not have an incentive to bid auctioned CRRs up to their expected value

These represent fundamental flaws that cannot be eliminated under the current market design. The last section of this paper discusses how these flaws could be addressed through a voluntary market for price swaps between willing buyers and sellers. However, this option should only be pursued if policymakers believe that the benefits of facilitating price swaps warrant or require intervention by the ISO, rather than allowing price swaps to occur through private mechanisms as occurs with other commodities.

CRRs are not consistently defined products in both the auction and day-ahead market.

In the monthly CRR auction, the ISO uses a transmission model developed at least several weeks, and as much as a month, prior to the relevant day-ahead market hour. The ISO conducts the seasonal CRR auctions at the end of the year prior to the settlement year. Many outages "...cannot be known until real-time operations..." and these outages can "...change the system configuration and result in different shift factors..." than used in the auction.[18] Different limits and network configurations are possible and likely. "Therefore, it might be that the assignment [of CRRs] is not, in all circumstances and under all conditions, actually feasible."[19]

When CRRS are auctioned based on a network model that is not feasible given the model actually used in the day-ahead market, this can cause revenue inadequacy. However, the use of different network models in the CRR auction and day-ahead market creates a more basic issue than revenue inadequacy. Different models mean the CRR product is defined differently in the CRR auction than in the day-ahead market. A CRR holder buys a specific bundle of forward contracts in the auction. But the CRR holder can be paid the day-ahead prices for a different bundle of forward contracts. The product purchased in the CRR auction is not the same product settled in the day-ahead market. Because the day-ahead market network model is not and cannot be known when the auction is run, it is uncertain what transmission constraint prices the CRR will settle on in the day-ahead market.

Consider a case where the ISO introduces a completely new constraint (Constraint A) into the day-ahead market. When Constraint A is binding in the day-ahead market, it increases payments to a CRR. When

[18] Bautista Alderete, Guillermo. "FTRs and Revenue Adequacy" in Financial Transmission Rights: Analysis, Experience and Prospects. Springer 2013. Edited by Juan Rosellón and Tarjei Kristiansen, p. 253.

[19] Harvey, Scott M, William W Hogan, and Susan L Pope. 1997. *Transmission Capacity Reservations and Transmission Congestion Contracts*. Cambridge, MA: Harvard University, p. 62 of the version at: http://www.hks.harvard.edu/fs/whogan/tccoptr3.pdf.

the ISO pays the CRR holder for the entire difference in day-ahead market congestion prices between the source and sink nodes, the ISO pays the CRR holder for a forward contract to the Constraint A which was not even modeled in the auction. The CRR holder is paid for this forward contract even though a forward contract to Constraint A was not purchased, or even offered, in the auction.

Under this scenario the ISO does not explicitly offer a forward contract for Constraint A in the auction, yet a forward contract for congestion on Constraint A is actually available. The CRR will be settled on the entire day-ahead market source-sink price difference, which includes the day-ahead market transmission price for Constraint A. This CRR is a different bundle of forward contracts in the auction than it is in the day-ahead market. At the time the CRR auction is held, it is not clear what constraints will be enforced in the day-ahead market. Therefore, it is not clear what forward transmission right contracts are actually available in the CRR auction.

Similar problems occur when the ISO models a constraint differently between the CRR auction and day-ahead market. Consider a 100 megawatt CRR whose source and sink locations both have .10 shift factors to another transmission constraint (Constraint B). The holder of this CRR would purchase zero net megawatts of forward contracts to Constraint B. If in the day-ahead market model the sink shift factor to Constraint changes to 0.05, while the source shift factor remains .10, the CRR holder would be paid for 5 megawatts of forward contracts to Constraint B at the day-ahead market price. Again the CRR holder never purchased forward contract for Constraint B. Different transmission models, as defined by different shift factors in the CRR model and day-ahead market model, can create the same or similar problems as non-modeled constraints.

CRR auction participants profit from better information on modeling differences without adding any efficiency or value to the market

Paying auctioned CRRs based on the full day-ahead market congestion price differences between the source and sink nodes is like allowing buyers to purchase regular gasoline now to sell at premium prices later. The network model in the auction is public information to the CRR auction participants. Auction participants can compare the public CRR auction model to their private estimates of the multiple network models over the month or season in which the auctioned CRRs will settle. An auction participant may find CRRs modeled in the auction as lower value, "regular," that the participant models as higher value, "premium." Profit maximizing participants will bid to obtain CRRs modeled in the auction as regular but which they anticipate to be premium.

Similar use of superior private information to bid into auctions has been studied in construction contract, government procurement, timber, and online advertisement auctions.[20] These studies show that the use of superior private information in auctions with inconsistently defined products can result in decreased auction revenues relative to the value of the product actually being auctioned.[21]

[20] As examples see:

Athey, Susan, and Jonathan Levin. 2001. "Information and competition in US Forest Service timber auctions." *Journal of Political Economy*: http://web.stanford.edu/~jdlevin/Papers/Skewing.pdf.

Agarwal, Nikhil, Susan Athay, and David Yang. 2009. "Skewed Bidding in Pay Per Action Auctions for Online Advertising" *The American Economic Review*: http://economics.mit.edu/files/10630.

[21] For procurement auctions it can result in increased payments to the auction participant relative to the value of the product or service procured.

A simple example CRR auction illustrates how a CRR auction participant can profit from having better estimates of the actual day-ahead market shift factors. The example auction has one constraint (Constraint X) with a 10 MW limit. Table 4 shows the auction bids, auction shift factors, actual day-ahead shift factors and actual day-ahead shadow value for Constraint X. Two auction participants (Company Y and Company Z) expect a $30/MW shadow value for Constraint X which equals the actual day-ahead market shadow price.

Table 5. Example of CRR auction with shift factors different than day-ahead market

Bidder	CRR Name	CRR Bid		Cleared CRR MW	Net Shift Factor		Bid Price Per MW		DA Mkt S.V.
		Price	MW		Auction	DA Mkt	Auction	Actual	
Company Y	A-C	$3.00	150	0	0.10	0.10	$30.00	$30.00	$30.00
Company Z	B-C	$3.10	150	100	0.10	0.15	$31.00	$20.67	$30.00

Company Y does not have better estimates of the day-ahead shift factors than the auction. Company Y wants a CRR between locations A and C, and bids the expected price difference between A and C of $3.00/MW. This equals the $30/MW value of the forward contract for Constraint X.

Company Z has better estimates of the day-ahead market shift factors. Company Z expects the actual day-ahead market net shift factor difference between locations B and C will be .15 and not the .10 modeled in the auction. Company Z bids $3.10/MW for CRRs between B and C. Company's bid appears to be $31/MW for forward contracts on Constraint X in the auction. Because $31/MW is greater than $30/MW Company Z is awarded all 10 MW of forward contracts on Constraint X (100 CRR MWs multiplied by the .10 shift factor). Company B pays ratepayers $310 in auction revenues (10 MWs multiplied by $31/MW).

But Company Z did not actually buy 10 MW of forward contracts on Constraint X. Because the actual net shift factor is .15, Company Z really bought 15 MW of forward contracts on Constraint X. Company Z's CRR is not a "regular" CRR with a 10 MW forward contract. Company Z's CRR is a "premium" CRR with a 15 MW forward contract. Ratepayers pay Company Z $450 in the day-ahead market (15 MW multiplied by the $30/MW day-ahead shadow value for Constraint X). Company Z's profits are $140 ($450 minus $310). Ratepayers lose $140 because they received $310 in auction revenues but paid Company Z $450 when settling the forward contract.

Company Z actually bids only $20.67/MW of Constraint X forward contracts ($310 divided by 15 MW). Company Z's bid appears to be $31/MW because the auction used the wrong shift factors and it appeared Company Z was only buying 10 MW. But Company Y is actually the highest bidder. Company Y's $30/MW bid is higher than Company Z's $20.67/MW bid. If the correct net shift factor for Constraint X had been used, Company Y would have won all the Constraint X forward contracts in the auction. Because the CRR auction uses different shift factors than the day-ahead market, the actual highest bidder does not win the forward transmission right contracts in this example CRR auction.

Ratepayers face significant limitations to bidding in auctions

The ISO determines the initial set of CRR forward contracts that ratepayers must offer at a $0 reservation price through the transmission limits set by the ISO in the CRR auction. If ratepayers wanted to auction off less CRR forward contracts than the quantity implied by the auction's transmission limits, ratepayers would have to bid into the CRR auction to buy the forward contracts. Ratepayers could in theory set reserve prices for the CRR forward contracts. They could set reserve prices by submitting price sensitive demand bids to buy CRRs. However, ratepayers face significant limitations to transacting in the CRR auction.

The costs for individual ratepayers to enter the auction obviously outweigh the benefits. Load serving entities therefore participate in ISO markets on the ratepayers' behalf. But load serving entities do not have a direct monetary incentive to manage the ratepayers' CRR forward contracts in the auction. One reason for this is that load serving entities directly pass through to ratepayers any profits or losses from these CRRs that are passively auctioned off by the ISO on the ratepayers' behalf.

Load serving entities also face regulatory hurdles from managing these CRR forward contracts. For example, see the procurement plan passage below:

> As the Commission determined in Resolutions E-4135 and E-4122, [The LSE] uses CRRs and LT-CRRs to hedge against congestion costs (expected and anticipated). [The LSE] does not use CRRs and LT-CRRs for financial speculation.[22]

The above passage reflects the prevalent misunderstanding of the current CRR auction design. Under the current CRR auction design, if load serving entities do not participate in the auction at all, ratepayers will be engaging in risky financial speculation. This is because running a CRR auction with non-zero transmission limits forces ratepayers to offer to sell risky CRR forward contracts at a $0 reservation price.

Regulations such as those cited in the passage above result in load serving entities not being able to purchase CRR forward contracts at auction. As a result, load serving entities cannot use explicit CRR purchases to help ratepayers avoid being forced to sell risky CRR forward contracts. Load serving entities can only bid for CRR forward contracts if they expect to use these CRR contracts to offset specific expected congestion costs as approved by the utility commission. Load serving entity procurement plans contain similar passages for all three investor owned load serving entities in the ISO.[23]

To purchase or set reserve prices on the CRR forward contracts offered by the ISO at $0 reservation prices, load serving entities would also need to determine what CRR forward contracts are actually being offered. As previously described, because CRRs are inconsistently defined products between the auction and day-ahead markets, LSEs cannot easily determine the set of CRR forward contracts being offered in the CRR auction. Load serving entities would likely find it difficult to purchase or set reserve prices on the CRR forward contracts if they do not know what forward contracts are actually available.

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[22] *Pacific Gas and Electric Company Conformed Long Term Procurement Plan, Attachment A, Clean Public Version*, 2012, p.158: https://pgeregulation.blob.core.windows.net/pge-com-regulation-docs/BundledProcurementPlan-Public.pdf.

[23] *Southern California Edison 2015 General Rate Case Generation Volume 4 – Power Procurement* p.2: http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/6A7265B21497F49F88257C210080D7A9/$FILE/SCE-02+Vol.+04.pdf
San Diego Gas and Electric Company's 2006 Long Term Procurement Plan, p.17: https://www.sdge.com/sites/default/files/regulatory/2006LTPP-Redacted.pdf.

Financial entities cannot be relied upon to bid auctioned CRRs up to their expected value

Ratepayers face significant economic, regulatory and technical hurdles restricting them from effectively bidding in the CRR auction. Therefore, ratepayers cannot effectively raise the reservation prices of CRR forward contracts auctioned by the ISO from zero up to ratepayers' willingness to sell.

However, CRR buyers competing for profitable CRRs might bid up the CRR prices. Because ratepayers are paid the auction revenue, they would receive the value of higher priced CRRs. If these CRR buyers compete by non-price methods, or transaction costs lower the buyers' willingness to pay, the auction prices they pay to ratepayers for the CRR forward contracts may not rise to expected CRR values.

Non-price competition for CRRs is any action to obtain profitable CRRs other than raising the prices paid for CRRs. For example, by creating better transmission modeling and forecasting tools CRR buyers can find CRRs that are undervalued or modeled differently in the CRR auction than in the day-ahead market.

Further, CRR auction participation is a complex undertaking:

> "...a typical FTR [a.k.a. CRR] desk has to deal not only with standard roles of trading financial products, but also the technical ones of power analytics. Building and operating a successful FTR business is a complex enterprise, with multiple factors to consider. Additionally, the still exotic nature of the product makes standard solutions from the trading industry difficult to use."[24]

To trade in the complex CRR auction many CRR buyers employ PhDs in electrical engineering. The complexity of CRR trading indicates that transaction costs are high. Transaction costs are the costs, other than actual CRR prices, of transacting in the CRR auction. Transaction costs are not only faced by the actual buyers in the auction but also potential buyers who did not enter the auction. Potential transaction costs for CRR auction participation may include:

- Obtaining technical knowledge of power flow analysis, finance, and CRR markets
- Obtaining knowledge specific to the ISO transmission system, outages, and operations
- Collateral requirements limiting total trades[25]
- Company risk management policies, particularly for companies whose main business is not CRRs
- Time and effort spent searching for modeling differences
- Opportunity cost of participating in other markets

CRR auction prices will likely fall as non-price competition and transaction costs increase. CRR buyers can also take advantage of having better and more flexible models of the day-ahead market models than the single model used in the CRR auction. With better models and better information, buyers can bid for CRRs they believe to be high value but which are modeled in the auction as low value. This is described in Section 4 above.

Any one of these or other factors may be preventing buyers from bidding CRR auction prices up to their expected value. The non-ratepayer CRR profits from CRRs are clearly large and consistent. Returns of over 100 percent are not consistent with a competitive auction.

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[24] Arce, Jose. "Trading FTRs: Real Life Challenges" in Financial Transmission Rights: Analysis, Experience and Prospects. Springer 2013. Edited by Juan Rosellón and Tarjei Kristiansen, p.271.

[25] Market participants must hold collateral for each megawatt of CRRs held as shown in *Business Practice Manual for Congestion Revenue Rights Appendix H. Credit Requirement* at: https://bpmcm.caiso.com/Pages/BPMDetails.aspx?BPM=Congestion%20Revenue%20Rights

4 Alternatives to the CRR auction

The ISO's day-ahead market is a centrally cleared market. In a centrally cleared market, power is not traded directly between market participants. It is sold *to the market* at the market price. Similarly power is bought *from the market* at the market price. The market price at any location is the locational marginal price. It follows that power is not shipped from one location to another. A CRR is not needed in order to have the ability or right to ship power between locations or for transmission access.

The demand for a hedge against locational price difference primarily comes from forward contracting on power prices. Suppliers, load serving entities marketers and financial entities trade these forward power contracts outside the ISO markets. A supplier may sell a forward power contact at a location different than the locations of any generation assets it controls. When this happens, the day-ahead settlement prices for the forward power contract and the generator's energy schedule will be different. The supplier will face an uncertain day-ahead price difference not hedged by the forward power contract. A supplier may be willing to buy a forward contract for the day-ahead price difference to hedge this uncertainty.

One alternative to auctioned CRRs would simply be a bilateral or exchange market for forward contracts for price differences between pairs of nodes. Forward contracts for price differences already exist in many markets today. They are called locational basis price swaps. A swap contract is relatively straight forward. The buyer of the swap pays the seller a price in the forward market. In return, the seller of the swap pays the buyer the spot price difference between two locations. Oren, Spiller, Varaiya and Wu detailed how pairs of forward contracts -- one contract at the "source" location and one at the "sink" location -- could be bought and sold to create a hedge on locational price differences with the same effect as a locational basis price swap.

Price swaps could be traded between willing counterparties either through an exchange or bi-laterally. Generators with forward power contracts at locations different than their generation assets would naturally benefit from decreased price differences between their power contract location and their generator location. The generators would be natural buyers of a locational basis price swaps.

Load serving entities with forward power contracts --and who own the day-ahead congestion rents -- would benefit from increased price differences between the power contract location and the generator location. Thus, a load serving entities could be a natural seller of a locational basis price swap. The same parties that benefit from trading forward power contracts could also benefit from trading forward contracts for price differences. Unlike a CRR forward contract, a price swap would be consistently defined in the forward market and day-ahead market. The buyer of the price swap purchases the right to be paid the day-ahead price difference between two locations by the seller. In the day-ahead market, the price swap seller pays the buyer this price difference. This is in contrast to a CRR which can be an inconsistently defined product because it can be a different bundle of forward contracts in the CRR auction than in the day-ahead market.

In a separate paper, DMM outlines several potential contract structures that can allow energy suppliers to hedge basis risk between the supplier location and trade hub reference prices using simple price swaps. Trade hubs give market participants a common reference price to settle forward contracts against and can increase the total potential trading partners available to energy suppliers and load serving entities. Simple price swaps can be used to allow suppliers to hedge basis risk while contracting at trade hubs.[26]

There is no clear rationale for the ISO to offer forward price swaps. However, policy makers may determine that there are benefits to having the ISO provide a market for price swaps. Financial swap exchange markets external to the ISO or facilitated by the ISO would result in *markets* connecting willing buyers and sellers. Alternative markets should produce prices reflecting participants' willingness to trade. This is in contrast to the current CRR auction – which allows entities to buy forward contracts from ratepayers even though these ratepayers (or their load serving entities) have not offered to sell such contracts into the auction. A market based only on trades between willing participants would also greatly reduce the potential for large wealth transfers from ratepayers to other participants. With these alternative markets any generator, marketer, financial entity, or load-serving entity could buy or sell forward contacts to hedge or speculate on locational price differences.

[26] Department of Market Monitoring "Market alternatives to the congestion revenue right auction" November 27, 2017: http://www.caiso.com/Documents/Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

Mr. UPTON. Thank you.

Next, we are joined by Max Minzner, partner of Jenner & Block LLP. Welcome.

STATEMENT OF MAX J. MINZNER

Mr. MINZNER. Thank you. Thank you, Chairman Upton, Ranking Member Rush, committee members. I appreciate the opportunity to be here today. My name is Max Minzner. I am a partner at the law firm of Jenner & Block. From 2015 until 2017 I was the general counsel at the Federal Energy Regulatory Commission and from 2009 to 2010 I was Special Counsel and the Director of Office Enforcement at FERC where I helped design and oversee the agency's enforcement program.

I believe that financial transactions play an important role in today's energy markets. However, I think it is worth distinguishing between two types of financial transactions. First, some transactions occur within the RTO and ISO markets. Generally, those financial products take their value from the sales of physical energy and are designed to facilitate the sale of physical energy in some way. Those transactions are generally FERC-regulated.

Second, some transactions in energy derivatives occur outside those markets. For example, trading can occur on ICE or NYMEX. To the extent that those transactions are regulated, the Commodity Futures Trading Commission oversees the markets where they are traded. This division leads to a core question for Congress and for Federal regulators: which products should be traded in the markets regulated by FERC and which products should be traded elsewhere?

To answer this question the Commission should focus on its role as the regulator of transactions in physical energy. In my view, considering the expertise, mandate, and jurisdiction of the Commission, financial products should exist within the FERC markets to the extent that they are helpful to improve the functioning of these physical energy markets. They should not be created or expanded past the point at which they are needed to ensure that the physical markets work efficiently and deliver value to consumers.

Right now, the financial products in the FERC markets generally serve this purpose. For example, virtual bids and offers can reduce price risk and improve reliability by aligning the prices in the day-ahead and real-time markets for electricity. Similarly, FTRs allow entities to reduce their exposure to the risk of price variations.

While these products do have real value for consumers, appropriate regulation of their trading by the Commission is important. For example, FERC has correctly worked to ensure that adequate credit requirements exist in the RTO and ISO markets. These requirements mandate that market participants have the financial ability to cover the obligations they assume. FERC also needs to carefully coordinate with other regulators. Given its jurisdiction, the CFTC has a role to play in this area. These two agencies need to work together to ensure coordinated regulatory efforts.

A robust FERC enforcement program is also crucial. Financial products have played a role in many of FERC's recent enforcement actions aimed at market manipulation. In particular, the Commission has often targeted a form of misconduct known as cross-market manipulation. Cross-market manipulation occurs when a market participant takes positions in two different but related markets. For example, a trader might obtain a large financial position in a product that derives its value from a relatively thinly traded physical energy product.

By making large trades in the physical product, the trader might be able to change its price in ways that enhance the value of the financial position. Even if there is a loss on the physical position it can be offset by a much greater gain in the financial position. The Commission needs to make sure it has the analytic and oversight tools necessary to exercise its enforcement authority effectively and thoughtfully.

Finally, the Commission should be open to improving its efforts in this area. These markets change quickly. As a result, the Commission should be frequently assessing the financial products and its markets, its regulatory approach, and its enforcement regime. Thank you again for the opportunity to be here today. I look forward to your questions.

[The prepared statement of Mr. Minzner follows:]

One Page Summary of Testimony of Max J. Minzner
Partner, Jenner & Block LLP
November 29, 2017

Financial transactions play an important role in today's energy markets. FERC should make thoughtful choices when setting the scope of the products traded in its markets in order to allow them to provide the most benefit to consumers. Financial products should exist in the FERC markets to the extent that they help improve the functioning of the physical energy markets.

Right now, the financial products in the FERC markets generally serve this purpose. For example, virtual bids and offers can reduce price risk and improve reliability by aligning the prices in the day-ahead and real-time market for energy. Similarly, FTRs allow entities to reduce their exposure to the risk of price variations.

However, appropriate regulation of these products by the Commission is important. For example, FERC has correctly worked to ensure appropriate credit requirements that mandate that market participants have the financial ability to cover their obligations they assume. FERC should also carefully coordinate with other regulators. Given its jurisdiction, the CFTC has an important role to play in this area and the two agencies need to work together.

A robust enforcement program is also crucial. Financial products have played a role in many of FERC's recent enforcement actions aimed at market manipulation. The Commission needs to make sure it has the analytic and oversight tools it needs to bring appropriate enforcement actions.

Finally, the Commission should be open to improving its efforts in this area. These markets change quickly. As a result, the Commission should be frequently assessing the financial products in its markets, its regulatory approach, and its enforcement regime.

Testimony of Max J. Minzner
Partner, Jenner & Block LLP

Before the Committee on Energy and Commerce
Subcommittee on Energy and Power
United States House of Representatives
November 29, 2017

<u>Introduction</u>

Mr. Chairman, Ranking Member Rush, and members of the Subcommittee: Thank you for inviting me to testify today. My name is Max Minzner, and I am a partner at the law firm of Jenner & Block LLP. From 2015 until 2017, I was the General Counsel of the Federal Energy Regulatory Commission (FERC or the Commission). From 2009 until 2010, I served as Special Counsel to the Director of the Office of Enforcement at FERC where I helped design and oversee the agency's enforcement program. In my view, the Commission has worked hard to harness the power of markets, subject to regulatory oversight, to ensure the reliable and safe provision of energy to consumers at just and reasonable rates.

I appreciate the opportunity to testify today on financial trading in the electricity markets. Financial transactions are a valuable component of today's markets and appropriate regulatory scrutiny is important to ensure a level playing field and the integrity of the markets. Let me start my testimony be distinguishing between two types of financial transactions. *First*, some transactions occur within the FERC-regulated markets. The Commission oversees six regional organized markets that handle wholesale transactions in electricity. These markets also trade financial products that take their value from the sales of physical energy. *Second*, some transactions in energy derivatives occur outside these markets. To the extent that these transactions are regulated, the Commodity Futures Trading Commission oversees the markets where they are traded.

This division between leads to a core question for Congress and federal regulators: Which products should be traded within the markets regulated by FERC and which products should be traded elsewhere?

In answering this question, I think the Commission and Congress should consider three factors. The first issue is the scope of FERC's jurisdiction. The Commission, at is core, is an agency that regulates transactions in physical energy products. The Federal Power Act and the Natural Gas Act regulate the sale of electricity and natural gas. The Commission is charged with ensuring that the rates, terms, and conditions of service comply with the requirements of those statutes. In contrast, as a general matter, FERC is not considered a financial regulator.

Second, the Commission's jurisdiction shapes the scope of its expertise. The Commission and its staff have a deep understanding of the markets in electricity and natural gas. That understanding is built on eight decades of regulatory oversight under the Federal Power Act and the Natural Gas Act dating back to the work of the Federal Power Commission. Its regulatory experience with financial transactions will necessarily be more limited.

Third, as the Commission authorizes products that are arguably also regulated by other agencies including the CFTC, the potential for regulatory conflict inevitably grows. Joint regulation by multiple agencies can have value, but comes with costs. Shared enforcement authority can provide a second set of eyes to identify and eliminate misconduct. On the other hand, entities that trade in these markets will need to comply with two sets of regulatory mandates. The burden of doing so can be significant.

These factors suggests an answer to the question outlined above. Financial products should exist within the FERC markets to the extent that they are helpful to improve the functioning of the physical energy markets. They should not be created or expanded past the point at which they are needed to ensure that the physical markets work efficiently and deliver value to consumers.

Right now, I believe the Commission's markets contain financial products that, broadly speaking, play this role. Let me highlight two of those products. The first are virtual bids and offers. Most FERC-jurisdictional markets operate on both a day-ahead and real-time basis. In the day-ahead market, buyers and sellers of power offer their supply and demand of electricity for the following day. These transactions are settled the next day and, to the extent that the supply or demand was not predicted correctly, the real-time market is available to close the gap.

Differences between the day-ahead and real-time prices and quantities can distort market outcomes and lead to inefficiencies. Virtual bids and offers are valuable tools to close these gaps. Financial traders can observe anomalies in the day-ahead market that are likely not to be reflected in the real-time market. Through appropriate bidding strategies attempting to benefit from these anomalies, virtual transactions can cause prices to move and arbitrage away these differences. In certain situations, virtuals can also help reduce or eliminate market power.

Second, many FERC markets offer a product called financial transmission rights or FTRs. These products take their value from the difference in day-ahead energy prices at two different locations on the electric grid. They can provide significant value to consumers of electricity because they allow entities to reduce their exposure to the risk of price variations. For example, load-serving entities have the obligation to provide power to retail customers. FTRs can allow these entities to hedge their risk of transmitting the power they need from generators to their customers.

Allowing financial transactions in FTRs helps provide liquidity and price discovery. A liquid FTR market ensures that the costs of FTRs are neither too high nor too low. Moreover, a liquid market can help improve decisions about transmission upgrades. Persistently high FTR prices reveal the existence of current or future congestion on the electric grid. These prices signal the need for new construction and assist transmission planners in their work.

These benefits can be best achieved through a sensible and reasonable regulatory framework. Financial transactions need to be appropriately, but not overly, regulated. The Commission should avoid treating financial players differently just because they are financial, rather than physical, participants in the jurisdiction markets. FERC should design the rules to maximize the benefit to consumers from these transactions.

For example, regional variations in organization markets are significant. Each FERC-jurisdictional market has its own unique market rules. These differences suggest that the nature and design of the financial products in each market may need to vary as well.

The Commission should also ensure that the market rules relating to financial products are designed to avoid imposing costs on other market participants. One example of this type of regulation is appropriate credit requirements that ensure that traders have the financial ability to cover the obligations they assume. The Commission has taken important steps to impose such credit requirements and this helps ensure the financial solvency of the markets.

FERC should also carefully consider the interaction between its rules and the requirements imposed by other regulators. Some have argued that aspects of the RTO markets are subject to CFTC regulation because of the nature of the financial products traded in these markets. The CFTC has provided an exemption for these markets given the pervasive regulation of the markets by FERC. Last year, the CFTC considered whether that exemption should extend to the private right of action under the Commodity Exchange Act. Working collaboratively with FERC, the CFTC eventually decided that the exemption should cover that provision as well.

That type of thoughtful joint action by federal agencies will be important in this space moving forward.

Finally, an appropriate and thoughtful enforcement regime is a crucial component of an effective program of regulatory oversight. Financial products have played a role in many of FERC's recent enforcement actions aimed at market manipulation. In particular, the Commission has often targeted a form of misconduct known as cross-market manipulation. Cross-market manipulation occurs when a market participant takes positions in two different, but related, markets. For example, a trader might obtain a large financial position in a product that derives its value from a relatively thinly-traded physical energy product. By making large trades in the physical product, the trader might be able to change its price in ways that enhance the value of the financial position. Even if there is a loss on the physical position, it can be offset by a much greater gain in the financial position.

The Commission's focus on cross-market manipulation is a sensible use of its enforcement authority and has a strong historical pedigree. Congress gave FERC its expanded enforcement authority in the Energy Policy Act of 2005. That statutory change was the direct result of the Western Power Crisis of 2000-2001. An important component of that event was a combination of poor market design and the use of financial products to benefit from the manipulation of the physical energy markets.

Despite its importance, though, cross-market manipulation is not always easy to detect and punish. In some cases, the conduct entirely within a FERC-regulated market because, for example, it involves physical and financial positions traded entirely within an RTO. In such cases, the Commission can "see" the entire transaction making detection more straightforward. On the other hand, though, components of the transaction only occur within the markets that the

CFTC regulates. In such cases, the Commission may only be able to directly observe a part of transaction and will be required to coordinate with the CFTC to obtain other information that it needs. FERC and the CFTC have worked hard to build a collaborative and effective relationship. The Commission to continue those efforts.

To its credit, FERC is an agency that has, from time to time, reexamined its enforcement practices. Let me highlight two of those efforts by FERC staff from November of 2016. First, FERC staff issued a white paper on compliance practices for energy traders. Compliance is a key area for financial traders to consider because an effective compliance program can significantly reduce or eliminate the potential penalty exposure for enforcement targets. Second, staff issued a white paper reviewing the agency's anti-market manipulation efforts over the decade since EPAct 2005. Combined with the agency's annual report on enforcement, these documents provide key guidance to the regulated community about the Commission's enforcement priorities and its view on the scope of its enforcement authority.

These efforts should continue. They are especially important in the area of financial trading. Financial markets inevitably move much faster than regulators. As a result, the Commission should constantly be reevaluating the financial products offered in its markets, the regulatory structure used to oversee these products, and the enforcement regime designed to ensure a level playing field for market participants and just and reasonable rates paid by consumers.

Mr. UPTON. Thank you.

Next, is it "Noah"?

Ms. SIDHORN. "No-ha."

Mr. UPTON. Noha—I am sorry—Sidhom, CEO of TPC Energy on behalf of the Power Trading Institute. Welcome.

STATEMENT OF NOHA SIDHOM

Ms. SIDHOM. Thank you. Good morning, Chairman Upton, Ranking Member Rush, and members of the subcommittee. My name is Noha Sidhom and I am CEO of TPC Energy, a privately funded power trading firm. I am here representing the views of the Power Trading Institute, otherwise known as PTI. PTI represents a diverse group of energy market participants ranging from large load-serving entities, suppliers, marketers, privately held commodity trading firms, as well as funds with investments in the power space.

My comments here today will focus on financial transmission rights known as FTRs. FTRs are essentially the price of congestion from point A to point B on the grid. These congestion contracts reflect the increasing value of transmission as more and more power flows across the lines from power supply resources to the customers consuming electricity. A good analogy is a toll road where the tolls increase during rush hour. As road capacity becomes tighter with more commuters driving to and from work, the price to use that road increases.

The same is true for electricity flow across the power grid. FTRs are purchased in an open and transparent auction that is connected by each RTO/ISO market. Market participants compete by submitting bids for specific megawatt quantity of FTRS on the transmission paths made available in the auction.

From the inception of the organized markets, the Federal Energy Regulatory Commission directed the creation of FTRs as a means to provide open access to the transmission grid. Congress demonstrated its commitment to forward pricing in the Energy Policy Act of 2005 by directing FERC to undertake a rulemaking to implement long-term FTR auctions. And we think Congress was correct and forward-thinking in supporting that framework.

Today, market participants utilize FTRs in a variety of different ways to the benefit of consumers. Load-serving entities who supply electricity to consumers utilize FTRs to hedge the risk of the price of congestion when serving their customers. Generation owners and developers utilize FTRs to hedge their risks to price volatility in the power markets.

Financial participants provide liquidity and competition in the FTR market which contributes to maximizing the value of the transmission system, a benefit to load-serving entities. Financial participants also utilize FTRs by including them in portfolios of diverse products to provide competitive risk management and hedging services to load-serving entities, generation owners, and generation developers.

FTRs save consumers money in three key ways. First, they provide an accurate price for the contracts that are allocated to transmission customers representing consumers. We are basically the tool on how to return those dollars back to transmission customers.

They provide a price for congestion on the grid to determine whether or not the cost of congestion is a more appropriate investment than the build-out of additional infrastructure.

So essentially, do we just want to pay for the cost of congestion or do we need to build new infrastructure? That is really important because if we overbuild the system consumers are going to pay for that for decades to come and it is going to cost them billions of dollars.

They provide a price signal to lenders financing infrastructure development and thus reduce the cost of financing. Over the past 2 decades of implementing FTRs as a core component of RTO/ISO markets, certain practices have proven to be successful and should be adopted in every market. Long-term auctions need to be implemented. None of the ISOs are in compliance with Order 681 which mandated auctions that cover at least the 10-year period. Currently, the longest term is 3 years.

Allocation of congestions costs caused by unplanned outages should be allocated to those who caused the costs to be incurred. New York ISO employs this practice and as a result has far fewer unplanned outages. Every other ISO should be encouraged to follow a similar practice. The FTR markets are robust and there is increased liquidity year-over-year. The Commission recently noted that there is zero evidence that a redesign of the FTR markets is warranted.

That being said, there are challenges both in the FTR markets and in the markets in general that impact the way the FTR markets function. The key challenges at a high level are lack of transparency and outage scheduling; network model updates that are not consistent or transparent; the price formation efforts at FERC should be expanded and expedited; and the technology utilized by the RTOS and ISOs need significant improvement.

Innovation and competitive prices for consumers are the core of our American economy. The Commission has spent the last 2 decades promoting these markets and the financial products that lie at the core of their creation and these economic concepts have worked to benefit your constituents. The way they think about electricity has fundamentally changed particularly over the last decade. Now we have to go the extra mile by ensuring market design flaws are fixed in short order, maintaining competition by expediting price formation efforts in long-term auctions, and pushing the RTOs and ISOs to take on a much-needed upgrade of their hardware and software systems.

It is our responsibility as industry members to work with you, FERC, and other stakeholders to ensure that these markets remain competitive, liquid, and fair to continue to benefit consumers. We look forward to working on future improvements and thank you for the opportunity to testify here today.

[The prepared statement of Ms. Sidhom follows:]

Noha Sidhom, CEO of TPC Energy, LLC on behalf of the Power Trading Institute

Subcommittee on Energy
Committee on Energy and Commerce
U.S. House of Representatives

Hearing: Examining the Role of Financial Trading in the Electricity Markets

November 29, 2017

I. INTRODUCTION

Good morning Chairman Upton, Ranking Member Rush, and members of the Subcommittee. My name is Noha Sidhom, and I am CEO of TPC Energy, a privately funded power trading firm with a focus on Financial Transmission Rights ("FTRs"). I am here representing the views of the Power Trading Institute ("PTI"). PTI represents a very diverse group of energy market participants, ranging from large load serving entities, suppliers, marketers, privately held commodity trading firms as well as hedge funds with investments in the power space. Our membership represents billions of dollars of investment in these markets, and a common thread for all of our companies is that we rely upon the financial products that are the subject of today's hearing in managing our day-to-day operations. PTI's mission is to advocate for markets that are open, transparent, competitive, and fair – all of which are necessary attributes for markets to ultimately benefit electricity consumers.

II. FINANCIAL PRODUCT OVERVIEW

Similar to other commodity markets, there are many types of financial products that are utilized by market participants within wholesale electricity markets. These products range from the familiar standard futures contracts and their derivatives to more tailored products that are specific to the power industry. There are financial products that were created specifically as part of the development and implementation of the organized wholesale electricity markets operated by the various Regional Transmission Operators

("RTOs") and the Independent System Operators ("ISOs"). All of these products are utilized by market participants to achieve diverse commercial objectives, which include, but are not limited to, securing revenue for an existing or future electricity supply resource, locking in electricity supply costs for consumers, or developing a portfolio of products in order to provide risk management and hedging services to other market participants. The trading of financial products results in a more competitive, liquid, and transparent overall wholesale electricity market, which benefits consumers at the retail level.[1]

The specific financial products that are part of the RTO/ISO markets are Financial Transmission Rights ("FTRs"), which are products with tenors ranging from 1 month to 3 years depending upon the RTO/ISO, and virtual transactions, which are products that are transacted in the next-day electricity market. This overview will focus on FTRs,[2] which are entitlements to receive or obligations to pay congestion revenues or charges on specified transmission paths on the power grid.

To provide some background in order to understand FTRs, the value of transmission congestion is determined in the day-ahead and real-time electricity markets through a complex optimization process of balancing electricity supply and demand while honoring the physical and reliability constraints of the power grid. Simply put, congestion reflects the increasing value of transmission as more and more power flows across the lines from power supply resources to the customers consuming electricity. A good analogy is a toll road where the tolls increase during rush hour; as road capacity becomes tighter with

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[1] *See, e.g.*, Thomas, et al., *Electricity Customer Choice in Ohio: How Competition Has Outperformed Traditional Monopoly Regulation*, Cleveland State University (2016), *available at* http://engagedscholarship.csuohio.edu/cgi/viewcontent.cgi?article=2420&context=urban_facpub; Compete Coalition, RTO and ISO Markets are Essential to Meeting our Nation's Economic, Energy and Environmental Challenges (2014).

[2] Long-term financial contracts are referred to by various names, Financial Transmission Rights, Congestion Revenue Right and Transmission Congestion Contracts, in the different organized markets but they operate in essentially the same manner.

more commuters driving to and from work, the price to use that road increases. The same is true for electricity flow across the power grid.

FTRs are directional; that is, a holder may purchase a right from point A to point B on the grid. If power flow originates at point A (think of this as a generator) and terminates at point B (think of this as a city), and there is congestion between point A and point B, the holder of the FTR is entitled to receive that congestion value.[3] However, if the holder owns an FTR in the opposite direction (from point B to point A), the holder is obligated to pay the congestion value that exists from point A to point B.

FTRs are purchased in an open and transparent auction that is conducted by each RTO/ISO. Market participants compete by submitting bids for a specific megawatt quantity of FTRs on the transmission paths made available in the auction. The auctions are conducted on a forward basis. For example, an auction for FTRs that span an entire year is run prior to the start of the year. There is a finite number of contracts that are auctioned off based upon the expected capability of the system. Each RTO/ISO uses an algorithmic model to determine who is awarded FTRs and at what price. The proceeds of the auction are distributed primarily to load serving entities, who supply electricity to consumers.

The competitive process of the auction provides the incentive for a market participant to bid economically in order to be granted FTRs. The results of each auction are made public to all stakeholders and what is unique to FTRs is that the owners of these contracts are also made public. Therefore, anyone can visit a particular RTO's/ISO's website to see which entities were awarded contracts and the prices associated with those contracts. These prices represent the forward price of congestion.

[3] RTOs/ISOs calculate prices at specific locations on the grid. The difference in prices between two locations on the grid, after adjusting for the value of electricity that is lost across transmission lines, is the value of congestion between those two locations.

From the inception of the organized markets, the Federal Energy Regulatory Commission ("FERC" or "Commission") directed the creation of FTRs as a means to provide open access to the transmission grid. The FTR product was approved nearly two decades ago by the Commission.[4] FERC found that FTRs "provide an effective method of protecting against incurrence of congestion costs when suppliers engage in transactions that use their firm transmission service reservations."[5]

Congress' recognition of the value of FTRs is most notable in Section 217 of the Energy Policy Act of 2005 (the "native load" provision). Through Section 217, Congress directed FERC to:

> *exercise the authority of the Commission under this Act in a manner that ... enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial transmission rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.*

Further, Congress demonstrated its commitment to forward pricing in the organized markets by directing FERC to undertake a rulemaking to implement long-term FTR auctions, Order No.681,[6] and we think Congress was correct and forward thinking to support long-term auctions.

III. FINANCIAL TRANSMISSION RIGHTS ARE KEY FOR CONSUMERS

FTRs are inextricably linked to the underlying delivery of power to customers, and they are integral to shielding consumers from the price volatility that comes with having to perfectly balance the grid every minute of the day. Today, a variety of market participants utilize FTRs in a variety of different ways to the benefit of consumers.

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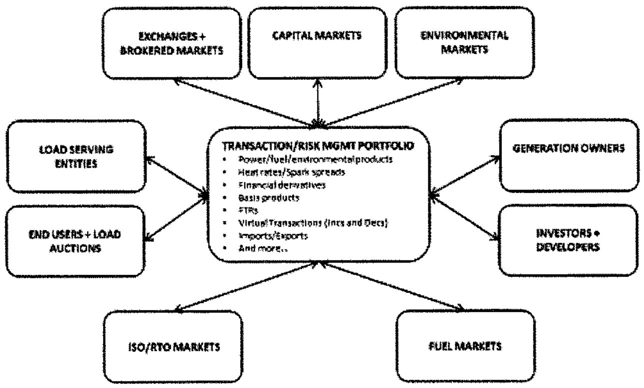
[4] Pennsylvania-New Jersey-Maryland Interconnection, 81 F.E.R.C. ¶ 61,257 (1997).
[5] Id. ¶¶ 62,257, 62,260.
[6] Long-Term Firm Transmission Rights in Organized Electricity Markets, Order No. 681, FERC Stats. and Regs. ¶ 31,226 (2006).

Load serving entities, who supply electricity to consumers, utilize FTRs to hedge the risk of the price of congestion when serving their customers. Generation owners and developers utilize FTRs to hedge their risk to price volatility in the power markets. Financial participants provide liquidity and competition in the FTR market, which contributes to maximizing the value of the transmission system, a benefit to load serving entities. Financial participants also utilize FTRs by including them in portfolios of diverse products to provide competitive risk management and hedging services to load serving entities, generation owners, and generation developers. Lending institutions who finance generation and transmission facilities often require use of FTRs and other bilateral transactions in order to hedge the risk of their investment. Without a proper forward price curve that is developed by forward congestion values from FTR auctions, suppliers, load serving entities, financial participants, and financial institutions would have to build in substantial risk premiums in order to be able to take on such significant risk without any type of hedging opportunity. This would effectively be a dead weight tax on consumers. Therefore, without FTRs, electricity prices would undoubtedly increase for ratepayers.

Financial Participants Play an Important Role in the Markets

Financial participants are positioned to offer a variety of transaction structures and risk management services to other market participants and provide liquidity and competition, all of which facilitate a robust market place. ***A robust market place is key in ultimately driving value for consumers of electricity.***



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Another critical point to note is that the forward price signal that FTRs provide to the market leads to more efficient infrastructure development. The organized markets have to balance the need for additional infrastructure development with the cost of congestion. Does it make sense to build a new transmission line or a new plant in a particular region or pay for the cost of congestion in that region, if that would overbuild the system to the detriment of consumers? The only way to answer that question is to have a forward price curve where willing buyers and sellers take on economic risk and provide a forward price

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[7] This figure demonstrates the various ways financial participants can be positioned in the market.

signal to evaluate the need for such infrastructure. It is important to note that the organized markets have not seen load growth over the past several years.[8] Overbuilding the system thus would be an unnecessary cost that consumers would bear for decades to come. The inextricable link between FTRs and the grid and the nature of their locational pricing make them a necessary tool for providing that balance.

You may be asking yourself, where does the money come from? Are the funds being paid to these FTR holders coming out of my constituents' pockets? The answer is a resounding no. Let's take a step back. The organized markets allocate FTRs principally to utilities that serve retail customers. These rights in total reflect the expected physical capability of the transmission system to deliver electricity; they are finite and their number is determined through analyses conducted by the organized markets. These finite rights are allocated to the transmission customers representing consumers that have paid for the fixed investment in the transmission system and are thus entitled to rights to the electricity transfer capability of this system. Transmission customers are allocated a certain number of contracts. How do we determine the value of these contracts that are provided to the transmission customer? It is important to note that only a percentage of these contracts are actually auctioned off, the majority are allocated. In fact, only the excess capacity is auctioned off in the FTR auction. The value of the allocated rights is then determined in the open auction. Bilateral contracts are also priced off of the auction price. Basically, this is a public auction of excess capacity.

When there is no liquidity in the open auction or competition to arrive at an efficient price, the value of that contract diminishes because parties build in a risk premium.

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[8] *See, e.g.*, PJM Interconnection, L.L.C., Where has Electricity Demand Growth Gone in PJM and What are the Implications? (2014), *available at* https://www.eia.gov/conference/2014/pdf/presentations/sotkiewicz.pdf; *see also* Analysis Group, Electricity Markets, Reliability and the Evolving U.S. Power System 27–28 (2017), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/ag_markets_reliability_final_june_2017.pdf.

Simply put, without a locational FTR market construct, there is no mechanism to price bilateral contracts or allocated rights.

In short, FTR auctions save consumers money in three key ways:

- They provide an accurate price for the contracts that are allocated to transmission customers representing consumers.
- They provide a price for the congestion on the grid to determine whether or not the cost of congestion is a more appropriate investment than the build out of additional infrastructure.
- They provide a price signal to lenders financing infrastructure development and thus reduce the cost of financing.

Some have argued that FTRs should not remain part of the RTO/ISO paradigm and that they should be traded outside the electricity market construct on a separate exchange. As discussed above, however, these rights are inextricably linked to the transmission system. The pricing of these rights is utilized in the transmission planning process; the number of rights allocated shifts based on the physical capability of the grid in a manner only the RTO/ISO can model and alter. And only the RTO and ISO can reconfigure the actual right, meaning they can change the path from A to B to A to C, if that is the more appropriate configuration that needs to be priced and allocated. In fact, FERC recently opined on the reconfiguration and reallocation of rights in PJM. Historical rights that were not reflective of the current transmission system were being allocated and that was causing distortions in the modeling and pricing. FERC mandated that PJM update its allocation process to allocate rights based on the current system and clearly stated that there is no evidence that the FTR market warrants a redesign.[9] Only the RTOs/ISOs can model the physical system constraints that will be applicable for the period auctioned in order to determine an appropriate price based upon the preferences of willing buyers and

[9] PJM Interconnection, L.L.C., Order on Rehearing and Compliance, 158 F.E.R.C. ¶ 61,093 (2017).

sellers. In addition, FTRs are paid from day-ahead revenue that is not just an exchange of money between FTR traders but rather a blend of complex activity by all market participants, including generation owners and load serving entities. An exchange would not incorporate this activity. As a result, taking these products to an exchange separates rational congestion management activity from the economic activity to balance supply and demand on the transmission grid and would ultimately increase costs for consumers. From a legal perspective, such a divided structure would go against the core principles of Order No. 888,[10] the key FERC order instituting open access. Incidentally, this structure is being discussed in the California stakeholder process and stakeholders have voiced these very same concerns.

Lastly, a forward price curve increases innovation by providing a price signal for entrepreneurs to invest in new technologies. Without such a forward price signal, investors would find it difficult to develop R&D budgets to explore new technologies not knowing the potential future value of such an effort. The organized markets have demonstrated this consumer benefit because indeed they have been a breeding ground for innovation.[11] For example, the organized markets were key markets for developers of increasingly cost-effective renewable energy generation facilities; they were the test beds for pioneering storage technologies and customer distributed generation, efficiency and demand response resources. The structure of these markets was also a driving force behind companies supplying new and improved methods for measuring and tracking all aspects of the physical system providing increased transparency. Lastly, these markets, and these financial products specifically, have also promoted the emergence of a

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[10] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996).

[11] PJM Interconnection, L.L.C., Resource Investment in Competitive Markets (May 5, 2016), *available at* http://www.pjm.com/~/media/library/reports-notices/special-reports/20160505-resource-investment-in-competitive-markets-paper.ashx ("PJM 2016 Resource Investment Whitepaper").

sophisticated financial sub-industry designed around the analysis of price and the forecasting of all major characteristics of variability and risk.

IV. BEST PRACTICES IN FTR MARKETS

Over the past two decades of implementing FTRs as a core component of RTO/ISO markets certain practices have proven to be successful and should be adopted in every market. We will address those best practices here but one thing we would like to stress to the Subcommittee is that at a broader level there needs to be a mandate for the RTOs and ISOs to evaluate and implement best practices, not just pertaining to FTRs but pertaining to overall market functions.

a. Long-Term Auctions Need To Be Implemented

We applaud PJM, New York and ERCOT for implementing a long-term FTR auction construct. PJM, New York and ERCOT are the only markets that have an FTR auction with a duration longer than one year. PJM and ERCOT have auctions going out as far as three years and New York has a two-year auction. This forward-looking price signal enables better price formation, more cost-effective infrastructure development, more efficient pricing of hedges and, as a result, consumer savings. However, none of the ISOs are in compliance with Order No. 681, which mandated auctions that cover at least a 10-year period. The logic behind the 10-year period mandate was to cover the planning horizon that is utilized in the transmission planning process. Specifically, Order No. 681 stated that:

> Long-term firm transmission rights must be made available with term lengths (and/or rights to renewal) that are sufficient to meet the needs of load serving entities to hedge long-term power supply arrangements made or planned to satisfy a service obligation. The length of term of renewals may be different from the original term. Transmission organizations may propose rules specifying the length of terms and use of renewal rights to provide long-term coverage, but must be able to offer firm coverage for at least a 10-year period.[12]

[12] Order No. 681, at 255.

While the RTOs and ISOs allocate rights to transmission customers for a 10-year period, they do not auction off FTRs for a 10-year period. The flaw with this paradigm is that there is no long-term forward price for that allocated right. This is akin to my giving you 10 shares of a stock and telling you I will tell you what it is worth in seven years. All of the FERC jurisdictional RTOs/ISOs should be mandated to come into compliance with Order No. 681 and implement long-term auctions. One to three year terms are simply not sufficient to provide liquidity for longer-term hedging or price discovery.

b. Allocation Of Congestion Costs Caused By Unplanned Outages Should be Evaluated

The New York ISO allocates congestion costs incurred due to unplanned transmission outages back to the transmission owner. As a result of this practice, New York ISO has far fewer unplanned outages and the transmission owners are diligent in communicating system maintenance to system operators. For example, as of November 26, 2017, PJM had 2,208 active and planned outages in total for the month; 1,178 were forced outages. New York, on the other hand, had 908 total planned or active outages for the month and only 243 forced outages.[13]

Market participants build a premium into their price for FTR contracts to manage the risk of these unplanned outages. New York ISO's approach to make those in control of the outage schedule accountable for the cost incurred to the system creates the right incentives, and based on the data, that economic incentive works. This practice also helps maintain reliability of the grid by communicating outages to the RTO/ISO in a timely manner. Every other RTO/ISO should be encouraged to follow a similar practice.

c. Options Contracts Should Be Made Available As A Risk Management Tool

[13] This outage information was obtained from Yes Energy, a third-party vendor, and only pertains to lines over 69 kV.

ERCOT is the only market that allows for the purchase of an FTR options contract at every path that is available for a traditional FTR contract. Options allow a market participant to limit their exposure by paying a premium for the option and locking in their downside to the transaction. Other markets have options for FTR contracts, but the availability of paths is very limited. Options are heavily utilized in ERCOT because they are an effective risk management tool. If all of the potential FTR paths were made available as an options contract, this tool would be utilized by market participants in every RTO/ISO to balance portfolios. A good way to think about this is comparing it to options in the equities market. Imagine if you were only able to purchase options of certain stocks but not others. In other words, the equities market would allow you to pay a premium for certain stocks but not others. This biases price discovery and limits a market participant's ability to manage risk by paying a premium to better manage downside risk.

V. CHALLENGES FACING MARKET PARTICIPANTS IN THE FTR MARKETS

The FTR markets are robust and there is increased liquidity year over year. To reiterate, the Commission recently noted that there is zero evidence that a redesign of the FTR markets is warranted.[14] That being said, there are challenges both in the FTR markets and in the markets in general that impact the way the FTR markets function. We address those challenges below.

a. Lack of Transparency in Outage Scheduling

[14] *See* PJM Interconnection, L.L.C., Order on Rehearing and Compliance, 158 F.E.R.C. ¶ 61,093 (2017) ("[T]he Market Monitor and Joint State Commissions reiterate the proposal . . . that the Commission should support a market redesign to ensure loads receive all congestion revenues. We reject the arguments that the sole purpose of FTRs is to return congestion revenue to load and the market should therefore be redesigned to accomplish that directive.").

As demonstrated above, there is a lack of transparency regarding the scheduling of outages. This lack of transparency costs consumers money because market participants have to build in a risk premium into their transactions to account for this prevalent practice of unplanned transmission outages. The New York ISO's practice of allocating costs caused by an unplanned outage back to the transmission owner and thus decreasing the number of unplanned outages clearly demonstrates that this problem can and should be solved.

b. Network Model Updates Are Not Consistent or Transparent

Market participants have very little transparency into updates to the network model that significantly impact the pricing of FTR contracts. Each ISO has a different practice for releasing model updates and they are often not released in a timely manner. Furthermore, often the amount of capacity that is auctioned off is drastically different from the prior auction with no notice and no transparency into the changes being made to the model. A consistent schedule for all of the RTOs/ISOs to release network model updates prior to FTR auctions would: (1) assist with more accurate price formation of the forward curve; (2) reduce any risk premium incurred by consumers due to this uncertainty; and (3) reduce pricing issues at the seams caused by disclosure of information in one market but not the other.

c. Revenue Adequacy Issues Have Been A Concern

The majority of the capacity on the system is allocated to load serving entities and excess capacity is auctioned off in FTR auctions to value both the allocated rights and the auctioned rights. The process of allocating the right-sized amount of capacity is not an easy one to get one hundred percent right, one hundred percent of the time. When too much capacity is allocated or auctioned off, there can be a revenue shortfall. In other words, there may not be enough day-ahead revenue to pay all of the holders of the transmission rights. At the outset, this is an issue a minority of the time. PJM experienced revenue adequacy issues from 2011 to 2014, but over the past 12 years, only three years have presented significant revenue concerns.[15] In PJM from 2005 to 2012, total net congestion costs were $11.3 billion, while auction revenues were $11.5 billion, resulting in excess funding. This demonstrates that the current market structure provides an efficient means to entitle holders of the allocated rights to the full economic value of the whole transmission system. The Commission closely evaluated this issue and was clear in stating that a redesign was not necessary. The FTR market is operating as intended and returns value back to consumers.

That being said, a lesson can be learned from the revenue adequacy concerns voiced by state regulators and others. Unplanned transmission outages and modeling issues have been the primary causes of underfunding.[16] Revenue inadequacy is not caused by the FTR product but rather by market design flaws that need to be resolved. Without the FTR product you would lose the transparency that highlights these market design issues. And there is no other way to value the allocated rights without the FTR product. It is the only fair and transparent way to price congestion and provide open access. The open auction process is integral for consumers because it is transparent as to ownership and competitive as to price. However, these market design flaws do cost consumers money because they force investors to build in a risk premium. The more confident market participants are in the design of the market, the better value consumers will get for the allocated rights. This revenue adequacy issue presents an opportunity for both FERC and this Subcommittee to take a critical look at improvements that can be made to RTO/ISO processes to ensure that consumers are in fact protected from revenue shortfalls caused by market design flaws.

d. Price Formation Efforts At FERC Should Be Expanded And Expedited

[15] The planning periods of 2011-2012, 2012-2013 and 2013-2014 were revenue inadequate by over 15 percent.

[16] *See* PJM Interconnection, L.L.C., Proposed Modifications to ARR and FTR Provisions, Docket No. EL16-6-000, at 7 (Oct. 18, 2015).

FERC has initiated several rulemakings over the past two years to improve price formation in the organized markets. The rulemaking regarding uplift allocation, which is essentially an out of market payment made to a unit that is called on in real-time to meet system needs, has not been finalized. In addition, the price formation docket was started in 2014, and the discussion regarding price formation has evolved significantly since that time. Today, we are discussing pricing attributes, not just environmental attributes but ramping capability and other functions that have become more integral as technology improvements have been made. These elements need to be folded into the discussion at FERC. In 2012, FERC held a technical conference on capacity markets and all of the economists called on to testify at that conference stated that the Commission should focus on getting the prices right in the energy markets. At that time, approximately ninety percent of the revenue in the wholesale market was earned in the energy markets. Today, approximately seventy percent of the revenue is earned in the energy market.[17] FERC has not taken speedy action on price formation issues and that has exacerbated some of the concerns voiced by generators that they cannot recover their costs. Expediting efforts to improve price formation in the wholesale market to provide a more transparent cost of delivering power would greatly benefit consumers and market participants.

e. The Technology Utilized By The RTOs/ISOs Needs Significant Improvement

Another significant challenge faced by market participants is the inadequate technology utilized by the RTOs/ISOs. Many of the systems utilized by these organized markets have not had a significant upgrade in over a decade. PJM, MISO, and CAISO have all experienced significant issues in solving their FTR models over the past several years. Most notably, PJM was recently a week late in solving its auction and did not solve until the settlement month began. In other words, market participants were incurring

[17] Monitoring Analytics, LLC, State of the Market Report for PJM, Vol. 2: Introduction, at 16-17 (Mar. 9, 2017), *available at* *http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-volume1.pdf.*

profits and losses but did not know which positions they had been granted in the auction until several days into the settlement month. This does not occur in any other commodity market.

Some RTOs/ISOs have suggested eliminating products, reducing transaction volume of certain products or have not implemented products suggested by their market monitors due to technology constraints. What this really means is that we are hindering price formation and liquidity in the market in the name of inadequate technology. This practice cannot continue. Large financial institutions as well as our intelligence community all process significantly larger sets of data in a small fraction of the time demanded of the RTO/ISO markets. The technology is out there and given the critical nature of our energy infrastructure to the United States economy, we should be deploying the most advanced technology practicable. In addition, there should be some level of transparency as to hardware and software upgrades made by the RTOs/ISOs to ensure that upgrades are occurring as necessary and that funds are being deployed in a manner that benefits consumers. Several years ago, the Department of Energy ("DOE") provided a $3 million grant to MISO to improve its day-ahead solution time as part of an effort to improve gas and electric market coordination. The goal was to allow for improvements so that MISO can release commitment results earlier and allow market participants to have that information prior to the close of the gas nomination cycle. Stakeholders have not been informed of how those funds were utilized and what improvements have been made to the day ahead engine. PTI is aware that PJM was also involved in that effort, but to our knowledge, a set of best practices or potential improvements has not been shared. It is our belief that more transparency regarding technology upgrades as well as additional information sharing between the RTOs/ISOs would result in better operation of the markets and save consumers significant dollars.

f. Procedural Changes Could Improve An Already Robust Enforcement Program

PTI strongly believes that FERC must have a robust enforcement program that has the tools necessary to prosecute bad actors in the market. None of our members want to engage in and deploy significant capital in a market that is not rigorously policed. And indeed, these markets are adequately policed with multiple layers of protection. First, the Market Monitor in each RTO/ISO has a wide latitude of discretion to request information regarding a market participant's transactions, provide guidance, make recommendations and refer cases to the Office of Enforcement. Second, FERC's Office of Enforcement has more than doubled in size over the past eight years and has been extremely active in policing the markets. Lastly, while the CFTC exempted financial transactions in the RTO/ISO markets from most of its statutory requirements, the CFTC made clear that it was not exempting these transactions from its enforcement authority.

Noting all those layers of protection, we think it is important to look at the number of investigations that do not result in any action by FERC. In 2017, while the Commission closed 16 investigations, 11 were closed without further action because staff concluded that the evidence did not support finding a violation. The 2016 Enforcement Report noted that the Commission closed 11 investigations with about half concluding no action was necessary.[18]

The 2017 Enforcement Report also noted two items of particular interest. First, the Commission conducted a full audit of a financial trading firm and concluded that no changes were necessary. Second, surveillance screens identified large, loss making virtual increment offers (INCs) at an RTO Hub placed by a market participant who held a leveraged FTR path sourcing at that same hub. The Division of Investigations contacted

[18] Staff of the Office of Enforcement, Fed. Energy Regulatory Comm'n, 2017 Report on Enforcement, Docket No. AD07-13-011, at 7 (2017); Staff of The Office of Enforcement, Fed. Energy Regulatory Comm'n, 2016 Report on Enforcement, Docket No. AD07-13-010, at 7 (2016).

the market participant and was informed that the entity held a tolling agreement with a generation facility in the RTO and that the contract priced against the real time locational marginal price. The market participant explained that the observed INCs covered a period of a planned outage, and that the virtual position shifted a non-leveraged real-time position to the day ahead market where the market participant hedged commodity risk. After verifying the information, the Commission closed the case. We note these examples to highlight that the nature of these transactions is complex, and thus they may lead to more of a dialogue with the Office of Enforcement, but this does not translate into ill-intended behavior in the market by financial participants.

Enforcement efforts come at a cost to market participants and ratepayers. Over the past five years, the Commission has gone from a compliance approach to its enforcement program to a surveillance approach. This change in dynamic has chilled the open dialogue that once existed between enforcement staff and industry. We believe simple procedural changes could be made to FERC's enforcement program to make it more effective for both the Commission and market participants. The first procedural change is requiring FERC staff to request the data prior to requesting the speaking documents (i.e., emails, IMs, employment contracts, etc.). The statute is a fraud-based statute with an intent element. One must establish fraud first and then go to the intent element. The speaking documents go to the intent portion and thus are not necessary until an analysis of the data has been completed to determine whether in fact bad behavior occurred. The speaking documents are also incredibly expensive to produce. There are many occasions where market participants have incurred millions of dollars of expenses producing speaking documents, only for enforcement staff to find no manipulative behavior in their review of the transactional data. These are unnecessary dollars spent.

The second procedural change is to allow for a non-public no-action letter process, similar to that available at other federal market regulators like the Securities and Exchange Commission and the Commodity Futures Trading Commission. Currently, FERC only has a public no-action letter process. The key issue here is that if a market participant wants to vet a strategy with the Commission, the market participant must then share its proprietary trading strategy with all of industry. FERC has stated that it would like to share its insight on these strategies to benefit all of industry and provide more transparency. However, an easy solution for this would be to only make public information regarding strategies where the Commission declines to issue a no-action letter. In other words, if the Commission thinks the transaction is in a gray area and would not issue the no-action letter, then it should make the details of that transaction (not the market participant) public to place others on notice that it views that particular strategy as potentially manipulative market behavior. If the Commission grants a no-action letter, it should keep the details of that market participant's proprietary strategy confidential.

Third, the Commission runs financial screens across positions and when those screens are triggered, an investigation can be initiated. The Office of Enforcement should make those screens public. There should not be an effort to hide the ball. Getting access to such screens would help companies build out better compliance programs, facilitate discussion between enforcement staff and market participants regarding the transactional data, and shed light as to Enforcement's views on what is considered market manipulation.

Fourth, the Commission should be encouraged by Congress to resolve enforcement actions as soon as practicable. Investigations sit idle for years making discovery more cumbersome and impacting businesses in a negative manner.

VI. CONCLUSION

Innovation and competitive prices for consumers are the core of our American economy. The Commission has spent the last two decades promoting these markets and the financial products that lie at the core of their creation. And these economic concepts have worked to the benefit of your constituents. The way they think about electricity has fundamentally changed, particularly over the last decade. Now we have to go the extra mile by:

- Ensuring market design flaws are fixed in short order.
- Maintaining competition by expediting price formation efforts and long-term auctions.
- Pushing the RTOs and ISOs to take on a much-needed upgrades of their hardware and software systems.
- Ensuring ISO/RTOs are implementing best practices and not delaying to the detriment of consumers.
- Maintaining a robust enforcement program at the Commission by making necessary procedural changes to re-open the dialogue between enforcement staff and industry to the benefit of consumers.

It is our responsibility as industry members to work with you and FERC to ensure that these markets remain competitive, liquid, and fair to continue to benefit consumers. We look forward to working on future improvements and thank you for the opportunity to testify here today.

Mr. UPTON. Thank you.

Next, Vince Duane, senior VP and general counsel for PJM, welcome.

STATEMENT OF VINCENT P. DUANE

Mr. DUANE. Thank you, Chairman, Ranking Member, members of the subcommittee. My name is Vince Duane. I am a senior vice president of PJM, and like my colleague to the right, Dr. Hildebrandt, I work for an organization that administers these markets, we don't participate in them. Indeed, our mission is simply to deliver wholesale electricity at the lowest possible cost to the consumer. And the litmus test for financial trading in these markets is whether it furthers that mission. Quite simply that is the question.

There are two points I would like to bring out to the committee's attention that bear on that question and that are unique to these electricity markets like PJMs. First, our core function is a physical function. We commit generation for sale and purchase and deliver it to the ultimate consumer. We do this with the assistance of financial products that trade alongside physical transactions and that is something that makes us quite unique relative to other commodity markets where primary physical markets are quite separate and distinct from secondary financial and derivative markets.

We are a little bit of a hybrid in our financial markets because we believe that financial products can bring liquidity, they can bring price convergence, and can bring pricing discovery to assist in the operation of the physical market, but that is the standard. There is no other independent basis for these types of transactions to exist in these FERC-regulated markets unless they meet that standard. There are other places for them to go.

We have in this industry our own secondary financial markets. Mr. Minzner made reference to some of them—NYMEX, Intercontinental Exchange. There are places to go outside of the FERC-regulated markets if there are other needs for financial traders and hedgers. The second point I would like to make is that these markets are complex. I don't think I need to say that but I will start with that point.

Some of you may have heard the term market design and indeed these FERC-regulated markets are very heavily engineered, very much rule-focused. We use rules, thousands of pages of rules, in fact, that are on file with the FERC in the form of a PJM tariff, and underlying those rules are models and algorithms that do two things generally.

One, we use these things to dispatch and commit generation to meet load to keep the lights on in the system and we do that in a way that sets prices. So when you have prices that are formed at least in part by market design, by rules and algorithms, we have learned a few interesting things over time.

First, price dislocations can and do occur, and if these dislocations are caused by a rule feature or by a modeling difference, no amount of financial trading is going to correct those price dislocations. In fact, it will just simply exploit and profit that dislocation without bringing the arbitrage value that you would theoretically expect to see.

Revenues in these systems are highly contested between asset owners and consumers. So where trading exploits a price dislocation without bringing any corrective value, essentially it is just siphoning revenues out of that system. It is a hole in the bucket and it is something that needs to be plugged as a hole in the bucket.

So in conclusion, the question is whether financial trading in these FERC wholesale electricity markets bring value. My answer is yes, but with qualification. The important point is you cannot assume the efficiency values that you would normally see in purely financial markets such as those administered by the SEC or the CFTC.

Those values are necessarily going to hold in these unique physical electricity markets. But if they are rationalized and if these trades are incented properly and if they are limited where necessary, they can bring benefits. They do bring benefits and transaction efficiency to the physical generation owner, to the transmission customer, and ultimately to the consumer. Thank you very much.

[The prepared statement of Mr. Duane follows:]

United States House of Representatives
Committee on Energy and Commerce
Subcommittee on Energy

Testimony of Vincent P. Duane, Senior Vice President, Law, Compliance & External Relations
PJM Interconnection, L.L.C.
"Examining the Role of Financial Trading in the Electricity Markets"

November 29, 2017

My name is Vincent Duane and I serve as a Senior Vice President at PJM Interconnection, L.L.C. ("PJM"). I have worked in competitive wholesale electricity markets regulated by the Federal Energy Regulatory Commission ("FERC") since their inception over 20 years ago, including over 5 years on the floor of a major energy trading firm active in PJM and the other FERC-regulated electricity markets. PJM is a Regional Transmission Organization ("RTO") responsible for ensuring the reliable and non-discriminatory planning and operation of the transmission grid and the fair and efficient administration of wholesale electric markets. The PJM region encompasses over 65 million people in an area that includes all or parts of New Jersey, Pennsylvania, Delaware, Maryland, the District of Columbia, Virginia, North Carolina, West Virginia, Kentucky, Ohio, Michigan, Indiana, Illinois and Tennessee.

Thank you Chairman Upton and the Subcommittee on Energy for inviting PJM to address this subject. The 'bottom line' of my testimony today is that financial trading in the wholesale electricity markets can enhance liquidity, aid in price discovery and provide hedging opportunities for those that generate and sell electricity into these markets and those, such as traditional distribution utilities, competitive retail providers and large customers, that buy directly from those markets. But like most things in life, one can have too much of a good thing or a good thing, but at the wrong time and place. Financial trading in the PJM markets is a "good thing." But financial trading in

PJM's markets cannot be presumed beneficial in *all* circumstances. Unique design aspects attendant to RTO electricity markets can work to prevent realizing the theoretical efficiency expected from trading. In these instances, RTOs and FERC must work to preclude those trades which, if allowed to continue, would only leak revenue from sellers or savings from buyers of physical electricity - offering no commensurate efficiency benefit to the system.

PJM recently filed certain reforms with the FERC for just this purpose: to preserve the value that financial trading can offer to PJM's markets while minimizing situations where trading siphons off revenues with no corresponding system benefit. These reforms should help additionally to reduce those instances, as noted in the Staff Memorandum prepared for today's hearing, where FERC's enforcement arm is forced to step in to curtail trading that simply exploits market rules offering no real benefit to the overall market.

1. RTO Markets Uniquely Blend Physical and Financial Transactions

Like other commodities, wholesale electricity is transacted both physically and traded financially. And like other financially traded commodities, specialized environments, such as exchanges and electronic trading platforms, have evolved to facilitate financial trading. For instance, financial electricity is traded on the New York Mercantile Exchange (NYMEX), the Intercontinental Exchange (ICE) and Nodal Exchange. These exchanges offer futures, options and swaps to trade electricity specific to PJM and at multiple locations (or nodes) on the PJM system. These so-called "secondary markets" in PJM electricity are not regulated by FERC. They are separate from PJM's FERC-regulated markets and affect PJM's markets only very indirectly.

While these secondary financial markets are not the subject of today's hearing, I raise them only to clarify that highly-developed, highly liquid and specialized forums exist for those that wish to hedge or speculate on PJM electricity prices outside of the PJM market itself. PJM's markets are fundamentally designed to facilitate the dispatch, purchase, sale and delivery of *physical* electricity from power plants to wholesale electricity buyers, who in turn sell retail electricity to homes and businesses.

In this sense, the auction-based day-ahead and real time electricity markets administered by PJM are not unlike a livestock auction – but one where wholesale buyers and sellers meet to transact physical electricity instead of say, live cattle. And just as is the case with financial electricity, separate secondary markets offered by exchanges (like the Chicago Mercantile) provide a place to trade agricultural commodities (like feeder cattle futures and options), quite distinct from the physical buying and selling that takes place at the livestock auction.

Wholesale electricity markets, such as PJM's, have one feature not shared by the livestock auction in this example, and one that uniquely distinguishes RTOs from markets in other physical commodities. Central to the commitment and dispatch operations of RTOs is a market designed to allow *both* physical and financial bids and offers. While banks, Wall Street trading houses and speculators do not show up alongside farmers, feedlot owners and large food companies at a livestock auction, these types of entities can and do show up alongside merchant and regulated power plant owners seeking to sell the output of their plants through PJM to municipal, cooperative, and private utility companies that buy this output to sell retail electricity to homes and businesses. In short, RTO markets provide a unique platform that accommodates both physical and financial transactions in an integrated fashion. This distinction is important for two reasons.

First, the voluntary participation of financial traders in PJM's fundamentally physical market is premised on an assumption that financial transactions alongside physical transactions in the same (as opposed to just in a secondary market) help the efficiency of the predominantly physical market. Some question the validity of this assumption arguing financial trading of electricity should take place only in secondary over-the-counter, exchange and electronic trading markets and not in RTOs. With some caveat discussed below, PJM disagrees and believes the construct allowing financial participation in its markets is both theoretically sound and its value borne out from actual experience.

Second, the metric for financial traders in PJM is whether in fact their participation facilitates and brings efficiency in meeting the market's prime objective – the commitment, dispatch and delivery of physical electrons from generation to load.

PJM, unlike a secondary market platform, at its core does not exist to support financial trading. As noted, other forums such as ICE, Nodal Exchange and NYMEX, perform this function and provide extensive opportunity for parties to hedge, speculate on and arbitrage PJM-specific prices and prices from other RTOs.

2. The Value Financial Trading Brings To PJM

Financial trading can add liquidity and contribute to efficient price formation in PJM's electricity markets. Financial traders participate in PJM's day-ahead energy market through so called "virtual" offers and bids for electricity (known in PJM parlance as "incs" and "decs" respectively) and through an instrument known as an Up-To-Congestion ("UTC") transaction. Traders also participate in buying and selling an FTR or financial transmission right, which offers the opportunity to hedge or speculate on price differentials between two points (or nodes) on the PJM system.

The theoretical basis to support "inc" and "decs" and FTRs is sound and the liquidity and convergence efficiency noted in the Committee Staff's Hearing Memo can be demonstrated empirically through analysis of historical price outcomes in PJM. The case to support the efficiency proposition of UTC transactions, which to my understanding are found only in PJM, is less clear.

"Incs" and "decs" and FTR's are integral components – not merely optional design features – to PJM's day-ahead and real time energy markets. While true that traders can realize some of their trading and risk management objectives on secondary market platforms, such as Nodal Exchange, ICE and NYMEX, their presence in PJM as virtual or FTR traders:

(i) provides these participants opportunities simply not available or not easily duplicated elsewhere,

(ii) improves the efficiency and price discovery aspects of PJM's energy markets, and

(iii) provides value to other PJM participants in the form of efficient prices and tools to build more structured risk management arrangements.

3. Recognizing Limits To The Value That Financial Trading Can Bring

RTO electricity markets are characterized by a high degree of rule and regulation; indeed the term "market design" is familiar to those involved in these markets. This term describes an elaborate set of rules, which are translated into models and algorithms and incorporated into software used by RTOs to execute complex mathematical optimizations. These outcomes work to clear markets and price a host of energy and energy-related products (known as "ancillary services") in order to produce the most economic commitment of generating stations consistent with the physical/operational constraints of the transmission and generation network.

But for today's hearings, the important takeaway is to appreciate the rules, models and algorithms that make up "market design" bear significantly on how prices are formed. In other commodity markets, recalling the example both of live cattle sold at the livestock auction and the feeder cattle futures contract sold on the Chicago Mercantile Exchange, prices form more or less where supply meets demand. And while true that offers and bids similarly form RTO prices, RTO prices *additionally* depend highly on market design, and the rules, models and algorithms underling this design.

The design structure of these electricity markets means that RTOs and FERC cannot accept categorically the proposition that financial trading *per se* improves efficiency by bringing convergence and the benefits of liquidity. Occasionally structural aspects of the market design will cause price dislocations, both locational (between one node/price point and another) and temporal (between day-ahead and real time). Theory might lead one to believe that trading would help arbitrage these price dislocations to bring convergence and price discovery. And indeed where electricity is "mis-priced" in one place or time relative to another due to a lack of information in the market or inaccurate forecasts or assumptions by the RTO or market participants, trading to "arb out" these price differences is valuable. But where instead these price differences result from structural market design features (rules, models, etc.), no amount of trading will "arb out" the price difference. Why? Because in these cases prices will converge only with a change to the market design - either a rule change or redesigning the models and software clearing the market. Trading this pricing inefficiency does not eliminate the inefficiency, it merely profits from it.

Financial trading itself cannot change rules or models; at best such trading highlights a consequence that might not have been understood by market designers. In this sense, false arbitrage trading is akin to taking advantage of a broken ATM. But more often, market designers cannot correct modeling discrepancies or align the differences in rules that lead to price dislocations because they exist for other purposes necessary to operation of the physical grid. While FERC has alleged market manipulation in certain cases where trading has exploited either design deficiencies or necessary design features, the onus in the first instance is on the RTO charged with market design to identify and anticipate structurally occurring price dislocations and either (i) reform the market design to eliminate the dislocation, or (ii) preserve the design for other reasons, but then eliminate the opportunity to trade around this design feature.

4. Recent PJM Reforms Relating To Financial Trading

PJM has pending before FERC two dockets that offer examples of steps that RTOs can and should take to right size financial trading and eliminate trading where structural or particular market design features work such that trading inherently cannot offer the efficiency benefits that might theoretically be presumed. Revenues in PJM are highly contested, both by suppliers questioning the adequacy of PJM prices to preserve the physical infrastructure needed for reliable operations and by consumers wary of paying more for wholesale electricity than is necessary. Financial trading that siphons revenues from PJM markets without offering commensurate efficiency benefits should be eliminated. This type of trading represents a "hole in the bucket" that PJM must plug by filing rule changes for FERC to approve.

PJM's pending reform proposals will affect UTC transactions most, "incing" and "decing" to a lesser degree, and FTRs not at all. In Docket ER18-86, PJM seeks to impose charges on UTC transactions commensurate to charges it already levies on other virtual transactions ("incs" and "decs"). The objective is to restore levels of traditional virtual trading with a demonstrated record of efficiency benefit, and reduce what, in the past decade, has been a dramatic increase in UTC transactions, whose benefits are more questionable. In Docket ER18-88, PJM seeks to eliminate financial trading from certain nodes that exist for other market operation purposes, but for idiosyncratic reasons, offer financial traders no opportunity to provide added efficiency to the system. Trading at these nodes simply taps a hole to siphon revenue out of the bucket.

As noted, some question altogether the unusual presence of financial trading in what otherwise is an overwhelmingly physical marketplace – having a Wall Street hedge fund manager attend the livestock auction, as it were. Again, as is often the case in life, there can be too much of a good thing or a good thing, but at the wrong time and place. Financial trading in the PJM markets is a "good thing." But it must be right sized and prevented in those limited situations where the market design is such that financial trading cannot deliver the efficiency benefit it might theoretically promise. Reforms of this sort will preserve the value that financial trading provides to PJM's markets, and minimize situations where trading is parasitic and where it attracts the attention of FERC enforcement.

5. Conclusion

Once again, PJM thanks this Subcommittee for the opportunity today to share our thoughts on the role of financial trading in FERC regulated wholesale electricity market. We stand ready to assist this Subcommittee as it examines this topic going forward.

Mr. UPTON. Thank you.

Last, we are joined by Chris Moser, senior VP of Operations for NRG Energy.

STATEMENT OF CHRISTOPHER MOSER

Mr. MOSER. Good morning, Chairman Upton, Ranking Member Rush, members of the subcommittee, and fellow panelists. My name is Chris Moser, senior vice president for commercial operations and all operations at NRG Energy. As such, I am responsible for the physical operation of our power plants as well as the purchase and sale of billions of dollars of coal, natural gas, and power each year.

My employer, NRG, is one of the largest owners and operators of power plants in the United States. Our portfolio includes conventional plants such as coal, nuclear, natural gas and oil, as well as a large renewable fleet of wind and solar generation. NRG also operates a retail business that serves approximately three million retail customers largely in Texas, but also in the eastern States that allow retail electric choice. As such, we come at this from both the merchant generation side and from the retail providing side.

As a purely competitive company with no captive ratepayers we earn what we make in the markets that we participate in. As such, we believe that fair and robust competition in the electric sector is the best means of delivering value to consumers. But that comes with risk, and management of financial and operational risk is critical to the competitive markets and those participants in the markets.

NRG relies on a wide variety of tools to manage those risks to remain competitive and to reduce the delivered cost of power to consumers. Included in this tool chest are a wide array of financial products traded within organized energy markets, traded bilaterally between market participants, and through centrally cleared exchanges. NRG uses FTRs and virtual transactions every day to hedge and deliver affordable power to consumers.

On the retail side, NRG uses FTRs to hedge against congestion charges on the transmission system which allows us to sell power to end use customers at predictable prices. By allowing us to protect against unforeseen congestion costs on the transmission system, we are able to offer customers affordable, fixed-price power offerings. Without these products, our company and others would have to charge higher prices to manage that increased risk, that risk premium. That cost would end up being included in retail sales which directly increases consumer costs.

On the wholesale side, NRG likewise utilizes financial products for price discovery and to ensure that our large central station generation receive a predictable price for the power that they produce. This includes selling power on a forward basis which allows NRG to lock in prices. It also includes purchasing FTRs to perfect those hedges and utilizing virtual transactions to move power sales from day-ahead market to the real-time market or vice versa. These tools are critical to the profitable operation of our power plants and to the overall stability of the wholesale competitive markets for electricity.

In conclusion, financial bilaterals, FTRs, and virtual transactions all play a critical role in the production and delivery of affordable power to consumers. I thank you for the opportunity to appear before the subcommittee and I am happy to help with any questions.

[The prepared statement of Mr. Moser follows:]

November 29, 2017

Before the Subcommittee on Energy
Energy and Commerce Committee
U.S. House of Representatives Washington, DC

Testimony of Christopher Moser,
Senior Vice President for Operations for NRG Energy, Inc.

Summary: NRG Energy, Inc. ("NRG") is an owner and operator of power plants across the United States. We also have a retail business that serves approximately 3 million customers. As a purely competitive company with no captive ratepayers, NRG and its shareholders bear the risks (and the profits or losses) associated with its participation in the wholesale and retail electricity markets. We believe that fair and robust competition in the electric sector is the best means of delivering value to consumers.

Management of financial and operational risk is critical to the competitive markets and the participants in those markets. NRG relies on a wide variety of tools to manage these risks and reduce the delivered cost of power to consumers. Included in that tool chest are a wide-array of financial products traded within the organized energy markets, bilaterally between market participants, and through centrally-cleared exchanges.

NRG uses Financial Transmission Rights ("FTRs") and "virtual" transactions every day to produce, hedge and deliver affordable power to customers. On the retail side, NRG uses FTRs to hedge against congestion charges on the transmission system, which allows us to sell power to end-use consumers at a predictable price. By allowing us to protect against unpredictable congestion costs on the transmission system, we are able to offer customers affordable, fixed-price, power offerings. Without these products, our company and others would have to charge higher prices to manage the increased risk. This "risk premium" cost would wind up being included in retail sales, which directly increases consumer costs.

On the wholesale side, NRG likewise utilizes financial products to ensure that our large central station generators receive a predictable price for the power they produce. This includes selling power on a forward basis, which allows NRG (and other generators) to avoid the potentially serious financial consequences of unexpected outages on the transmission system by purchasing FTRs and utilizing virtual transactions to move power sales from the day-ahead market to the real-time market, or vice-versa. These tools are critical to the profitable operation of our power plants and to the overall stability of wholesale competitive markets for electricity.

Testimony

Good morning Chairman Upton, Ranking Member Rush, members of the Subcommittee and fellow panelists. My name is Chris Moser, and I am Senior Vice President for Operations at NRG Energy, Inc.

Background on NRG and My Role at the Company:

NRG is one of the largest owners and operators of power plants in the United States. Our portfolio includes conventional plants powered by coal, nuclear, natural gas, and oil, as well as a large fleet of wind and solar generators. NRG also operates a retail business that serves approximately 3 million retail customers, largely in Texas and in Eastern states that allow customers to choose their retail electricity provider. Thus, NRG comes at the issues before the Subcommittee this morning from both a competitive generating and load serving perspective. I am responsible for operations at NRG, which includes the physical operation of our power plants, as well as the purchase and sale of billions of dollars of coal, natural gas and power each year.

NRG's business is premised on one key concept: that fair and robust competition, and not monopoly, is the best tool for providing value to consumers. As a purely competitive company with no captive ratepayers, NRG and its shareholders bear the risks and the economic consequences – positive or negative – associated with its participation in the wholesale and retail electricity markets. As this Subcommittee has heard in previous hearings, some companies are seeking corporate bailouts to undo the results of competition in the electricity markets. NRG's position is very different. We urge this Subcommittee to ensure that the organized markets utilize competition to drive investment in energy infrastructure, lower costs for consumers, and provide reliable electricity to power the economy.

One important contributor to such competition is ensuring that our markets have effective rules for price formation. Another is that policymakers say "no" to bailouts when competition produces a different result than some companies might want. Today's focus is on the third leg of the stool – ensuring that companies operating in competitive electricity markets can use financial trading and hedging tools to manage risk. This Subcommittee can help ensure that the Federal Energy Regulatory Commission focuses on all three of these important contributors to competition in our electricity markets.

Financial Products are a Critical Part to Delivering Low Cost Power to Consumers:

Financial transactions are an important tool we use every day at NRG. In organized markets, electricity prices should include: (i) the cost of the underlying commodity; (ii) a congestion component, which reflects the value of electricity in varying locations and takes into account physical constraints on the transmission system; and (iii) transmission line losses, which reflect the fact that some electricity is lost as it flows across a transmission line. As the Subcommittee's Hearing Memo noted, "[w]holesale electricity is a volatile commodity with prices that can change dramatically throughout a given day…" This volatility only increases as we deliver power into "load pockets," which are typically constrained areas of the transmission system where the transmission losses and congestion components of electricity pricing can be higher.

Proper pricing of electricity involves some degree of volatility as market participants respond to pricing and other dynamics. High prices signal to consumers that they may wish to reduce their consumption of energy during a period of high prices, and low prices tell generators that they should decrease their output. Financial products allow us to manage this volatility and deliver reliable, low-cost power to end-use consumers.

NRG's Sales of Forward Power:

The organized markets and associated financial exchanges are critical to allowing NRG to "hedge" expected production of electricity from our power plants. Forward sales of power provide us a predictable stream of revenue from the expected generation capability of our power plants, while allowing consumers to lock-in their long-term power costs. For example, entering 2017, NRG had sold forward 30% of its expected generation capacity for 2017-2020 in the Eastern portion of the country. In Texas, the number was even higher, with 46% of our coal generating capacity being sold forward in 2017-2020.

Without access to forward financial markets, NRG would be entirely dependent on spot market pricing to determine whether the continued operation of any of its power plants will be profitable or not. Because forward sales of power are typically based on today's prices, issues like wholesale market price formation are a top priority for the company – price formation effects not only today's revenues, but also those we receive in the future. This is particularly true in markets without capacity markets (such as ERCOT) or markets where capacity revenues are not established on a competitive long-term forward basis (such as the California ISO, Mid-Continent ISO, and New York ISO). In such markets, forward sales of power are the best way to determine if a particular power plant will be profitable in the long run or if a particular capital investment is warranted.

NRG's Use of Financial Transmission Rights:

NRG utilizes Financial Transmission Rights, or FTRs, in three primary ways:[1]

Retail Power Sales:

NRG purchases FTRs to hedge its retail sales of power. In the organized RTO/ISO electricity markets, there can be significant differences in the price we: (i) receive for sales from our power plants and (ii) pay to purchase power needed to serve our retail load obligations. These price differentials result from the fact that NRG's generation resources or power purchases are not always co-located with the customers we serve, which exposes NRG to the risk of congestion on the transmission system. Electricity costs more to make and deliver in crowded (or "congested") areas of the grid, such as large cities or areas that are far from generation.

NRG utilizes FTRs to manage this risk and provide predictable and stable prices to its end-use customers. Specifically, NRG can purchase an FTR along the path between a generating facility (or, more likely, a liquid point on the system, usually known as a "hub") and its end-use customers. For example, New York City's electric grid is as congested as its roadways. So if NRG sells electricity to a customer in the middle of New York City from a power plant located in upstate New York, it is likely that the transaction will incur additional congestion charges. Without FTRs, it would be difficult to predict exactly how much we would pay in extra congestion charges and we would have to include a larger "risk premium" in our prices to account for that uncertainty. A higher risk premium directly increases the price paid by end-use consumers. Purchasing an appropriate FTR, however, allows the parties to "lock in" those congestion charges, eliminating much of the congestion risk in exchange for an upfront payment.

Of course, purchasing FTRs costs money, which may reduce the profits we would otherwise earn. But the tradeoff is that we will not lose large amounts of money if unexpected

[1] While not the focus of my testimony today, NRG also engages in limited speculative FTR trading.

congestion appears on the system. Overall, FTRs allow NRG to protect against unpredictable congestion on the transmission system, minimize the costs to retail customers, and increase our ability to offer customers long-term, fixed-price power deals.

Wholesale Power Sales:

FTRs are also critical to the process of selling our generation output to other retailers of electricity. For example, NRG often sells power from its power plants on a bilateral basis to other companies, who then re-sell the power to end-use consumers. The organized electricity markets facilitate these bilateral sales by providing both parties with open access to the transmission system and clear, transparent prices.

Whether the buyer or seller takes the risk of congestion is often a significant negotiating point. Sellers of power typically prefer that all risk of congestion (or even outright failure of the transmission system) transfer to the buyer at the point where the power plant injects the power into the grid. Buyers, on the other hand, typically prefer that the seller maintain the risk of successfully delivering the power. FTRs allow either party to manage the risk of transmission congestion by buying an FTR. If the sale of electricity is ultimately accompanied by any additional congestion costs, then the FTR makes the parties whole for those costs. Thus, FTRs provide an "insurance policy" against the risk that congestion will appear on the system and substantially alter the economics of the underlying transaction.

FTRs are particularly important when selling the output of large-scale renewable generators, which are often located far from load. In many cases, generators located far from load are subject to increased risk of congestion between the point of injection into the power grid and the point of delivery to an end-use customer. FTRs protect both sides of the transaction from congestion risk, which facilitates stable prices for both buyers and sellers of renewable power.

Transmission System Investments:

FTRs can be a powerful means of attracting additional at-risk capital into the transmission system, which is typically dominated by utility investment using captive ratepayer dollars. Most organized markets permit non-utilities to pay to upgrade an "element" of the transmission system that constricts the flow of power from Point A to Point B. In exchange for fronting the capital to make or advance the construction of the upgrade, the investor receives the value of any additional power flows across that element, usually in the form of FTRs or related products. Thus consumers receive new or accelerated improvements to the transmission system, while investors only make money to the extent the new/upgraded transmission improvement is actually used. This moves risk from captive customers to private investors, while increasing total infrastructure investment.

NRG's Use of Virtual Transactions:[2]

NRG likewise uses virtual transactions to manage sales from its power plants and to manage retail market positions. Virtual transactions are a powerful tool for managing the risk inherent in two-settlement electricity markets, where some power sales take place in the day-ahead market (the first settlement), and other sales take place in the real-time market (the second settlement). Prices can diverge between day-ahead and real-time markets as physical conditions on the grid evolve over time. These price differences are critical to the proper functioning of electricity markets, and are often caused by changing load forecasts (i.e., as we get closer to real-time, we better understand consumer demand, based on weather and other factors), changes in generator or transmission line outages, changing fuel costs, or other factors.

As a result, it is often more or less advantageous to sell (or purchase) power in either the day-ahead or real-time markets. Virtual transactions allow generators to pay a (usually small)

[2] As noted above with FTRs, NRG also engages in limited speculative trading of virtual power.

fee to "virtually" shift their sales of power from the day-ahead to the real-time market, if conditions warrant.

Conclusion:

Financial bilaterals, FTRs and virtual transactions all play a critical role in the production and delivery of affordable power to consumers. On the retail side, these products provide a "hedge" against unexpected congestion charges on the transmission system. On the wholesale side, these products ensure that generators receive a predictable price for the power they produce.

Thank you, again, for the opportunity to appear before the Subcommittee today on these important matters. I would be happy to answer any questions that Members of the Subcommittee might have.

Mr. UPTON. Well, thank you. Thank you all. We will now go to questions from the Members, I guess.

The first question I have, Mr. Allen, you indicated in your testimony that—I believe you said—the western alliance did not participate in virtual traders. Is that right?

Mr. ALLEN. Yes.

Mr. UPTON. So which States are in that western alliance?

Mr. ALLEN. It is the western Energy Imbalance Market, so it includes Utah and Nevada, parts of Colorado. It is dispatched as a part of the California Independent System Operator, but convergence bidding—that is what they call virtuals in California—is only allowed in the California ISO proper. So most of California and a little sliver of Nevada is the only place where virtuals are allowed to——

Mr. UPTON. So by not having that would you say that those folks in those States then pay, the consumers, themselves, likely pay a higher utility cost, higher electric cost?

Mr. ALLEN. Higher than they would otherwise with the competition and the liquidity that virtuals add. Yes, sir.

Mr. UPTON. Let's see. Ms. Sidhom, in your testimony you explained that financial markets participants increase competition and efficiencies in the electricity markets. Can you explicitly state how the trading of those FTR instruments makes the markets more efficient?

Ms. SIDHOM. Absolutely. So essentially what is happening here is, you know, Dr. Hildebrandt explained these transactions as a price swap and that is exactly what they are. FTRs are a price swap. It is a fixed for floating. So the load-serving entity gets the fixed and a financial entity will take on that floating risk. So they are basically shifting risk away from consumers and onto companies like mine that are willing to take on that risk and can manage that risk and offer hedging services.

So when you have all this competition in the market and market participants that are willing to bid in an open and transparent auction so you can go into any RTO/ISO Web site and see who got the contract in the auction and the price they got the contract, there are also multiple rounds systems of these auctions so there is multiple opportunities for load-serving entities to have some price discovery, as Mr. Moser was saying, to then offload some of their risk in multiple rounds.

So essentially what we do is we go in and we provide liquidity and price competition to benefit the consumer and shift that risk of the volatile market away from them.

Mr. UPTON. You also said in your testimony that they needed to have an upgrade on the hardware and software.

Ms. SIDHOM. Yes.

Mr. UPTON. So I mean, where are they in that process?

Ms. SIDHOM. That is an excellent question.

Mr. UPTON. Do they understand the problem? I mean do they——

Ms. SIDHOM. We don't have a really good answer to that question because there is not a lot of transparency as to what software and hardware upgrades have been made. We know DOE had a $3 million grant that they gave to the Midwest ISO to improve their day-ahead solve time so essentially so that when generators get committed in day-ahead they have some time to procure the gas. It is a gas-electric coordination initiative.

We really don't know where those funds went, what the upgrades were like, what upgrades are necessary. It is kind of all a big black box to us. But what I can tell you is that several of the RTOs and ISOs have had a hard time solving their auctions and that is an issue for us because that is a risk. They may not solve the auction until the settlement period so you essentially have positions on that you don't know what your profits and losses are.

So that is a big concern. Financial institutions in this country are utilizing great technology and they are processing far more information than the RTOs and ISOs are and so is our intelligence community. So we would really like more transparency into what upgrades are necessary and a plan just like any private company would plan, OK, over the next 3 years, here is how we are going to spend dollars on making technology upgrades.

Mr. UPTON. Thank you.

Mr. Minzner, so as you talked particularly in your formal role at FERC, have you found that the CFTC and FERC have worked pretty well together as it relates to the transactions in terms of their oversight role? Are there real squabbles? Are there things that we need to know about?

Mr. MINZNER. I think now their relationship is quite good and the agencies have begun to work well together and have been effectively able to coordinate their enforcement programs. I think the relationship has waxed and waned. You may be familiar with a case several years ago where the agencies ended up litigating against each other in the DC Circuit over the scope of enforcement authority.

I don't think anybody would view that as a desirable outcome, but I do think as the leadership of the agencies have worked together, tried to build the relationship, and tried to build relationships at the staff level, many of those issues have passed and I do think now the relationship is much stronger and much more effective.

Mr. UPTON. Thank you.

Mr. Rush?

Mr. RUSH. Again I want to thank you, Mr. Chairman.

Ms. Sidhom, am I pronouncing it right?

Ms. SIDHOM. Yes.

Mr. RUSH. Do you believe that FERC currently administers the financial trading market in a truly open, transparent, and competitive way that best serves the interests of consumers, and if reforms are needed do you believe that they could be accomplished best administratively through a commission, or is congressional action needed?

Ms. SIDHOM. I don't believe congressional action is needed. I think you guys already took the appropriate action in EPAct 2005 promoting long-term auctions. I think that FERC just needs to actually push the ISOs to go in that direction and again push them on the technology initiative.

The Commission recently looked at PJM's market design for FTRs and they basically said this is working for consumers. It is saving them money. It is providing the necessary competition. The FERC was very clear there is no redesign warranted. It is very important for these transactions to actually occur within the RTO/ISO paradigm because the RTOs and ISOs are the only ones that can model the constraints.

They can say, OK, we have a transmission line that is coming online in 3 years from now. We have a unit that is retiring here. We can reconfigure the right. So we used to have load from A to B. That is where the load concentration was. Now we have it from A to C, so we are going to reconfigure the path where we need to price that congestion. They are really the only ones capable of doing that so it is so important for them to remain as part of the paradigm and FERC agrees. They don't agree with us often, so I think it is great that they recently agreed with us.

Mr. RUSH. Mr. Allen, in your written testimony you say my concerns from a previous hearing regarding the potential for RTOs to shut out public interest and participation and you said, and this concern should extend beyond consumers to encompass all minority interests in the ISO/RTO stakeholder process, including financial market participants.

How would PJMs propose reforms that FERC is currently considering regarding the up-to congestion impact in this process and, more specifically, what effect would these reforms have on consumers?

And Mr. Duane, would you also chime in on that question?

Mr. ALLEN. Thank you, Ranking Member Rush. I think the UTC case that came out of the PJM stakeholder process is a perfect example of the minority interest that is not being protected. If you look at the way the voting structure is in PJM for the stakeholder process there is five different categories of voting—generation owners, transmission owners, load-serving entities, and financial market participants are one of those as well. Most of the PJM membership it is lumped into what they call the other supplier sector which is the sector financial market participants are lumped into.

And just so you know, if an IPP or an independent power producer is building a power plant, until that power plant goes online they are lumped into the other supplier sector. So like I was saying, most of the membership is there. And if you look at how the voting occurred in the PJM stakeholder process you had basically the utilities voting in one way and then everybody else voting in a different way, but it passes because the utilities, you know, have a large share of market power in the stakeholder process.

So I do think reforms are necessary. And, really, when I think about a stakeholder process I wonder, you know, I can understand having a stakeholder process to determine smaller issue things, but when it comes to market design and features, I think, you know, a lot of that regulation should not be coming from the utilities or from stakeholders. It should be coming from the FERC or from Congress, someone other than—it is analogous to the inmates running the asylum.

Mr. RUSH. Mr. Duane?

Mr. DUANE. Thank you, Mr. Rush. And I see we have limited time so I will try and be very brief here. There is a lot to say, but I will just refer you back to the fundamental test at least in our belief is that financial trading has to benefit the physical participants and the system as a whole including the consumers and the generators, transmission customers. So our stakeholder process overwhelmingly voted in favor of these reforms and that covers both load interests and supply interests.

Ultimately, at the end of the day the question of whether these transactions bring that kind of value that I am describing will have to be resolved by the FERC and that is why they are there, to address those types of controversies.

Mr. RUSH. Thank you. I yield back.

Mr. UPTON. Mr. Olson?

Mr. OLSON. I thank the Chair, and welcome to our six witnesses, the special Texas howdy for Chris Moser. I can see NRG's biggest power plant, the Paris Power Plant in Thompson, Texas, from my house. That plant generates 36,000 megawatts of power. Four Powder Basin coal trailers come down — trains come down every single day, 115 cars. They have four generators of natural gas power and four generators with coal power.

And one coal power is very special, it is called Petra Nova. They capture over 95 percent of the CO2 in the process, put in a pipeline, sent it about 60 miles south southeast and get oil out of the ground. That is happening right now in my hometown, or in my home district of Texas 22. I can see that from Sugar Land, Texas.

OK, my brag about Texas is over. Let's get serious.

Mr. Moser, unlike others on the witness panel today, your company mainly uses financial products like an insurance policy. What would happen if these financial products aren't available?

Mr. MOSER. The risk that we are otherwise covering with those insurance products would either be borne by us and passed through to consumers at what we think, you know, what we estimate that would be or we would have to find a replacement product which would not be administered by the PJM or the ISOs. We would have to go to Nodal Exchange or something like that to try and fill it somewhere else.

Mr. OLSON. Is it different for retail and wholesale products, I mean differences between those markets?

Mr. MOSER. So as far as FTRs go, the FTRs as they are constituted and show no difference between a retail or wholesale when all you are doing is locking in the congestion basis between two points and they are equally effective for hedging either generation or retail.

Mr. OLSON. And how often does a trade go bad and what kind of internal oversight do you have to make sure that doesn't happen?

So we have a very fulsome risk process and risk policy and a risk department which oversees the trades that we put on. And the definition of a trade going bad is probably different between me and from one in which a strictly financial participant is. So when I am talking about hedging I am literally saying I sold something for $30 and I am buying it for $28 and I have locked in $2 of margin.

So I am indifferent to what the FTR does because it is in effect, if I paid $5 for the FTR and it comes in at 4 that looks like a loss of 1, but in effect I was getting rid of risk and I am happy because I locked in my margin. However, if a purely financial or spec trader bought something for 5 and ended up settling for 4 that would be the definition of a bad trade. For me it is a hedge, it is not a bad trade. It was eliminating risk that I wanted to eliminate.

Mr. OLSON. Thank you.

Now let's bring in Mr. Allen. I understand that each region offers different types of financial trading products. From your experience, are there certain RTOs who offer unique or particularly successful types of financial trading products? If so, please explain.

Mr. ALLEN. Yes, sir. I do. I think it is called ERCOT.

Mr. OLSON. I am familiar with ERCOT.

Mr. ALLEN. What is unique about ERCOT, you know, ERCOT in Texas has the most vibrant retail market. And I think part of the reason why they have the most vibrant retail market is they have the widest availability of financial instruments to allow retail competition. And what we have been advocating for both at FERC and in the stakeholder process and now here before you, we would like to see a point-to-point product—that is why they call it an ERCOT—in all the ISOs. It is an excellent mechanism by which it, you know, people can use it, retail load-serving entities can use it to hedge.

The FTR is great. The FTR is a longer-term instrument. It is a minimum of 1 month out a number of years. The point-to-point product is a daily to real-time product that—it exists somewhat in PJM, although they are trying to get rid of it. It is a central for retail competition hedging.

Mr. OLSON. Mr. Moser, do you care to brag about Texas, too, like Mr. Allen? ERCOT?

Mr. MOSER. Yes. So ERCOT is different than a lot of the other markets in a couple of fundamental ways. First of all, it is one of the few places where we see load growth. There is very little load growth in other places. Texas is growing between, depending on how you do the math, 1½ and 2 percent.

Other markets, the other major difference is Texas is an energy-only market. We only make money when we are dispatched and we run or when a customer freely chooses for us to be their retail electric provider. You know, we are not a utility in that respect, but we also don't have any capacity payments, which are—call it insurance policies that other assets and other markets have.

Mr. OLSON. My time has expired. Chairman, I did not mention my Astros being the baseball World Series champions. I yield back.

Mr. UPTON. We are proud of the Astros.

Mr. McNerney?

Mr. MCNERNEY. I thank the chairman. I don't really need to brag about California every time I get the microphone, Chairman.

You know, I found your testimony very enlightening, you know, there is so much to learn. It is a complicated market, so thank you for coming and giving us your testimony. I would like to start with Mr. Hildebrandt.

Do you consider yourself to be like an inspector general of the Cal ISO system, I mean analogous to Federal agencies?

Dr. HILDEBRANDT. I wouldn't call it inspector general. It is called the independent market monitor. FERC requires each RTO/ISO to have one. I think I view our job is to be, you know, analyze the data, monitor the markets closely, and call it like we see it, objectively, for both the FERC, for our management, for the board, and for stakeholders as well.

Mr. MCNERNEY. Well, how would you respond to Mr. Allen's remarks about the Energy Imbalance Market, his claim that their entry to Cal ISO improved efficiency and reduced greenhouse gases?

Dr. HILDEBRANDT. Well, I think he was—the question to him was why don't they have virtual bidding and if they did I guess would it lower prices. And the reason they don't have virtual bidding is there's no day-ahead market in the Energy Imbalance Market. So to have virtual bidding you have to have day-ahead market and real-time market. There is no day-ahead market in the Energy Imbalance Market, so of course they don't have virtual trading there.

Mr. MCNERNEY. So it is not a real clear case.

Dr. HILDEBRANDT. It is not an issue. You know, if they were to join the California ISO and have a day-ahead market they would therefore have virtual trading as well.

Mr. MCNERNEY. One of the things you mentioned was that the markets should be organized to allocate auction revenues better. You sort of dwelled on that. How would you go about doing that?

Dr. HILDEBRANDT. Well, I think where—so as I tried to lay out we agree that FTRs should be used to allocate congestion revenues back to the transmission ratepayers, but we are calling on the ISOs to not auction off additional FTRs. And if they did that all the congestion revenues, if there was just no auction it would automatically go back to transmission ratepayers.

Ms. Sidhom, I think her first point was that FTRs are a way of getting congestion revenues back to ratepayers.

Mr. MCNERNEY. Right.

Dr. HILDEBRANDT. Well, if you just don't auction them they automatically go back to ratepayers. And they are doing a very bad—the FTRs, if you view it as an instrument for returning congestion revenues to ratepayers they are failing miserably at that. In California they are only returning 50 cents on the dollar and in other ISOs it is more, maybe 80 cents on the dollar.

So they are not returning—so our proposal is pretty simple, is allocate FTRs to load-serving entities but then don't auction off the rest, a lot of those congestion revenues to go back ratepayers. If, you know, the free market, they are free to buy and sell hedges, insurance, if you will. You know, I think that is the role that financial entities they are very creative people. They are good at managing risk. I think they are free to sell price swap contracts to generators such as NRG to hedge their risk.

And we think that mechanism, a market between, you know, willing buyers and sellers is what will give you the correct, efficient, and fair price for I think what has been called, here, insurance policies.

Mr. MCNERNEY. All right, thank you.

Mr. Minzner, you sort of dwelled on the cost market and manipulation between the physical market and the sort of financial markets. How would you propose that they be better regulated? Is there an important distinction that needs to be made between the types of transactions or how would you do it?

Mr. MINZNER. So I think that is a great question. You know, cross-market manipulation has been something the agency has focused on in its exercise of enforcement authority ever since EPAct 2005, which arose out of the western power crisis largely focused in California. I do think FERC has been doing a good job at looking at this type of conduct trying to build the analytic and oversight tools it needs to be able to detect the conduct and when appropriate stop it.

I do think it is an area where the agency has had to make sure it has the data it needs about trading both in the FERC-regulated markets as well as the markets regulated by the CFTC and other regulators. As you can imagine, for market participants they care about the financial positions they hold broadly across all the markets, so it is important for the agency to make sure it can see all of those positions. I think it is an area where the agency has been succeeding largely, but it is certainly a work in progress.

Mr. MCNERNEY. I wanted to ask you a question, Ms. Sidhom, but I have run out of time, so you will have to take it up with another—I know you wanted to respond to Mr. Hildebrandt's comments. I yield back.

Mr. UPTON. Mr. McKinley?

Mr. MCKINLEY. Thank you very much, Mr. Chairman. Sorry that I slip out. Like you said, we have another meeting going downstairs to get back to.

I missed some of the presentations that you had, particularly Mr. Duane's comments from PJM. But we have had a series of hearings in the last year-plus over resiliency and dependability in our grid, and so as a result perhaps, I know, I think in your testimony you were going to say something about the rule, or the directive coming from the DOE over to FERC, how to take care of this.

One of the arguments that I have heard here so many times in committee has been market rates. The market rate should make that determination. Well, I am in agreement to some extent, but the market rate there should be a difference between market rate and dependability rates so that we know when we have a polar vortex or some problem that we know we can count on their being power available to folks.

Because of this pricing system that we have set up, I am concerned about how that could be, how that is going to come into play if FERC were to recognize that dependability is just as important as market rate. Because on market rate I am trying to find an insurance policy for people that during bad weather they are going to have electricity.

And I know it has been a very divisive issue ever since that has come out, and we know that in PJM 20 percent of the power plants went down during that period of time. So I am looking for that kind of support level in the pricing.

So, Mr. Duane, if you can give me some, a little bit better explanation, a little bit of how the financial trading tools, how they could be impacted if FERC were to come out with some kind of movement which in many respects it would be like an insurance policy that would give us some assurance that we are going to have power for our grid.

Mr. DUANE. Right. Thank you, Mr. McKinley. You know, you are touching as you point out on a very complex and controversial area and it is a fair question to ask right at the outset, are these organized markets returning a price that is fully valuing all aspects of the infrastructure that people are relying on to keep their lights on and to heat their homes and power their businesses.

It is a fair question because you can't assume in these markets that just where supply and demand meet you will get the right price because, as I mentioned, they are very highly engineered and revenues in these markets are very highly contested. You have the Department of Energy asking the Commission right now, are these markets adequately compensating generators for the full panoply of value that they are providing or is there something missing in the markets.

And the gauntlet that has been thrown down when you also consider on the other side of the equation are consumers who are very wary of paying any more than they need to for electricity. So we have to ask ourselves a question, is the system working? Are the prices correct? When you hear the term price formation that is really what it means, are prices being formed correctly in these very heavily designed markets.

The point of interplay with the financial trading is if we are not getting any efficiency value to assist in these markets from financial trading it really is siphoning revenues off the top. It is a hole in the bucket in the system. And the squabbling that is going on between load and generators as to whether generation is getting paid enough, whether load is paying too much, you know, there is another point to be made here is like, well, are we running a system that is fully efficient or are we having some leakage here so that the pie is shrinking.

And I think the point here is there is a lot of value for financial trading, but where it isn't providing value it needs to be curtailed and limited, rationalized, so that we do preserve revenues to support the physical participants in the market.

Mr. MCKINLEY. We also spoke at the last hearing about the Longview Power Plant and the impact that has as the most efficient coal-fired power plant in America, but because of the network of pricing they are having trouble being able to market their electricity into the system. And so you all were going to get back to me. I haven't heard from anyone yet.

Mr. DUANE. OK. Well, I apologize for that. I am not familiar with the request itself, but we will definitely get back with you on an examination of that question. We are very familiar with the Longview Plant. It is a relatively recent coal plant, highly efficient waste coal facility. It is located right on top of the Marcellus Shale fields so it does face stiff competition from a lot of new combined cycle generation.

But your larger point and I think it is one we agree with at PJM is that when you are running a reliable system over the long term and you want resiliency, putting all your eggs in one fuel basket doesn't sit well with a lot of engineers and planning people, so we are sensitive to the point.

Mr. MCKINLEY. Thank you very much. I appreciate it. I yield back.

Mr. UPTON. Mr. Peters?

Mr. PETERS. Thank you, Mr. Chairman.

I wanted to get back to Ms. Sidhom. So it is always a little difficult because I get, you know, we don't have a discussion. We sort of get six pre-prepared things which are all very interesting, but I am trying to connect where the differences are. What I would like to see, maybe you could respond to Mr. Hildebrandt's concern that consumers aren't getting the value of these trades particularly on FTRs.

Ms. SIDHOM. Absolutely. So I think California is unique in that it has some of its own challenges with the markets. And the problem is not with the FTR product, the problem is with the market design. They have got significant modeling issues so they will clear you out of the money all the time. Meaning, let's say, I will just give you an analogy of the equities market to keep it simple.

Let's say you want to buy a stock for $30 and your broker comes back and says we sold it to you for $60. That happens in California all the time. There is something wrong with their pricing model. Also, their outage scheduling is a real problem so about over 50 percent of the time the outages are not submitted in a timely manner to be modeled in the auction and that is what causes a lot of what Dr. Hildebrandt is referring to as revenue adequacy, so the underfunding of the payments going back to the load-serving entities.

So it is not the FTR product that is the problem. You absolutely need the auction because the auction is how you actually price the allocated rights. So essentially, you allocate rights to load-serving entities and then how do you get a price for those allocated rights. I give you ten stocks, what is the price for them? The price for them is obtained when the access capacity is auctioned off. I don't know how else you would be able price them.

As Vince's testimony stated, the FTRs were an integral part of the market design. They weren't just an option, they are how we provide open access.

Mr. PETERS. OK. Mr. Hildebrandt, can you respond to that?

Dr. HILDEBRANDT. OK. Working backwards, it is absolutely incorrect that the allocated, we call them CRRs, FTRs are priced based on the auction. They are allocated out, load-serving entities hold them, and they get paid the congestion revenues. So by not selling them, they get a dollar, the full dollar in congestion revenues versus which is on average a price in the auction which is only 50 cents on the dollar.

So the ISO allocates to load-serving entities. They keep those. They keep the congestion revenues. But then the ISO auctions off additional FTRs which sell for 50 cents on the dollar and those are bought primarily by financial entities with—and then the payout directly reduces the pot of congestion revenues which otherwise then gets fully refunded back to transmission ratepayers.

So, and as California is different, it is true the payout, our analysis shows while it is 50 cents on the dollar it may be more like in the 70 or 80 percent range in the other ISOs. But in other ISOs across the country, and we have now almost a decade worth of experience that even in the other ISOs ratepayers are only getting back about 70 or 80 cents on the dollar of the congestion revenues that they are paying for.

Mr. PETERS. So would there be some margin where they shouldn't get back, do you think they should get back a hundred percent?

Dr. HILDEBRANDT. Well, if entities are buying these as hedges, if I am a generator and I am buying them as hedges I would actually expect a hedge to go for premium. If I am buying an FTR to take away the uncertainty of my congestion, I am a generator, I am NRG and I want to sign a deal somewhere for the fixed price and I want to get my power there from a generating plant, I should be willing to pay a premium. In fact, I think the hypothetical example he offered had him losing a dollar on the FTR.

The fact is these are, they are earning, you know, it is an insurance policy that pays you, you know, a hundred percent on your premium. So it is not, so that analogy I think doesn't work.

Mr. PETERS. OK.

Dr. HILDEBRANDT. And, you know, if they were being purchased as hedges we would expect the price to be, you know, equal or above the congestion revenues. I guess our final point is you don't need the ISO to run that auction because basically we are auctioning off things, insurance that is backed that is subsidized by ratepayers. Let the transmission ratepayers decide if they want to enter into those contracts.

Have a market with if you want the ISO to run it, run a market if you don't think, you know, that private trading firms can do that, if you have the ISO run it base it on real bids from willing buyers and sellers. The financial entities here can offer to sell hedges, the generators here can offer to buy hedges, and if you want the ISO to run that market that is fine. But don't ask the transmission ratepayers to subsidize that.

Mr. PETERS. Ms. Sidhom, again, I have 7 seconds. Go ahead.

Ms. SIDHOM. So there is a risk premium built in because of these outages and that is why those dollars are not going back.

Mr. PETERS. Right.

Ms. SIDHOM. That is what is really creating the risk for the buyers. And so there is a risk premium that is being built in, but it is because of the market design issues.

Mr. PETERS. It suggests that it is market design.

Mr. Chairman, I would yield back.

Mr. UPTON. Mr. Shimkus?

Mr. SHIMKUS. Thank you, Mr. Chairman. This is a great hearing. I want to commend Mr. Peters. It is a great way to engage with our panel is to try to find where there is discrepancy and I just want to thank him for doing that. I am going to follow a little bit along because, you know, we are concerned about the national grid and reliability, but we also have our local parochial interests that deal with these markets.

So I would like to start with Mr. Duane on in dealing with when the transition from regulated markets to the RTO model, PJM converted many entities from transmission rights to these financial transmission rights. How do you protect against additional risk for those who have lost their firm transmission rights? Are there entities that end up becoming losers in this transition?

Mr. DUANE. It is a very fair question. The transition really took place quite a few years ago, really over a decade ago, and I think it is fair to say the transition from being a firm physical customer to having a financial transmission right, which as Ms. Sidhom said is a fundamental element of the design structure, that was a fair exchange.

What has happened though is nothing is static. The system changes. Load grows in different places. Load disappears in different places. Generation comes, generation goes. That changes the typology of the system and, frankly, the FTR was intended to anticipate those changes and provide options. Not just market options, but opportunities for people to designate different pathways.

People being typically in PJM, these are load-serving entities who are trying to manage the risk of congestion or price differential. And as the system changes physically, there are opportunities that the FTR provides to reconfigure your pathways to reflect how electricity is more realistically flowing to you today as compared to where it was, say, 10 years ago.

But short of transmission infrastructure build, there will be customers that are not as hedged today under this system as they would have been 10, 12 years ago.

Mr. SHIMKUS. Right. And I would speak to expanding our transmission grid to allow those more flexible markets instead of, in essence, kind of dedicated pathways and convoluted systems that sometimes we develop.

I want to go to Ms. Sidhom and Mr. Allen real quick. On financial trading institutions such as yours when you execute financial trades with the purpose of making a profit, when your company makes money from a financial transaction such as this financial transmission right, where does the payment come from?

Ms. SIDHOM. So we are basically offering a product. The payment comes from us offering this product which is where we are basically saying, look, we want to take the risk away from consumers, so how do we do that? We are natural buyers and sellers to—or we are basically the willing buyers and sellers to natural buyers and sellers, so that is where the payment is coming from. We are basically offering the other end of that transaction liquidity in the market.

Mr. SHIMKUS. Mr. Allen?

Mr. ALLEN. Yes, that is correct. Now there is a differentiation between what our two entities do. They are more FTR-focused. I am focused on the day-ahead and real-time. If we add efficiency to the market, if we improve the commitment, if we improve the reliability of the system then we make a profit. If we create inefficiencies or we get the day-ahead wrong then we lose money.

Mr. SHIMKUS. OK, so let's go to the consumer. Do the consumers pay for your payout through their electricity bills?

Mr. ALLEN. Well, each ISO acts as essentially a clearing broker where all of our transactions are cleared. So I put in buy and sell orders with PJM, they return whether we make or lose money. One thing to point out and I think it is important and it is in my written testimony. What is the load-weighted price of electricity in PJM? Wholesale level $29.23, so under $30. What is the retail rate in that same area? It is about $110 a megawatt, so wholesale prices are cheap. They are really cheap.

Mr. SHIMKUS. Ms. Sidhom?

Ms. SIDHOM. Yes. I mean I think we absolutely save the consumer a lot of money. Both in MISO and PJM, they estimate over $2.5 billion of savings a year from having these markets in place. You know, these are heavy policed markets. The CFTC is looking at us, FERC is looking at us. We have market monitors like Dr. Hildebrandt looking at us. If FERC thought that we were siphoning money from consumers I think they would have put a stop to these transactions a long time ago.

Mr. SHIMKUS. I have 730,000 people watching me, so—anyway, yield back.

Mr. UPTON. Mr. Green?

Mr. GREEN. Thank you, Mr. Chairman, for holding the hearing.

Mr. Moser, in your testimony you talk about FTRs hedge against congestion charges for end user, end user consumers. How much risk is there from the congestion charges that could potentially be pushed to consumers if it weren't for this product?

Mr. MOSER. Well, it would be pushed indirectly to them basically to the extent that none of the—or very few of—and when I am talking about retail consumers here, I am talking about homeowners not the large commercial and industrials who have a more sophisticated way of going about it and tend to shoulder some of the market things directly. But in terms of consumers, if the FTRs didn't exist and we had to price that in then rates would go up.

Mr. GREEN. In the Texas retail market, of course Texas is different as we say all the time from other markets, but retail market, where do we most often see congestion being an issue and how are these products used within the State?

Mr. MOSER. Yes. We have historically seen a decent amount of congestion coming from the western part of the State where you have a lot of the wind assets flowing into through congested lines trying to get to Dallas and trying to get down into Houston. Texas has built the CREZ lines to try and alleviate the into-Dallas area portion and then they are working on a Houston import project right now to try and alleviate some of those congestions.

But those are two of the classic ones. Really, anytime you are talking about congestion you are talking about, you know, assets, generation far away from load pockets and so the load pockets are often the congested pieces.

Mr. GREEN. In the wholesale market when it comes to selling forward on a basis how do these products mitigate potential losses?

Mr. MOSER. So when we use, and this is different than just FTRs, right. I mean, you know, through ICE, which was explained by Mr. Minzner and others, we can go out and see where the price of next year, next month is trading. We can put positions on, sell some of our expected generation and lock, and then go and buy some fuel against that lock in what we expect to be our generation spread, our profit.

But those sales are often at hubs where people agree to gather and make bulk purchases and sales. What we then would do would be go and try and perfect that hedge by using the FTRs to move where we have that sale to a location that approximates our generation plant.

Mr. GREEN. OK. In your testimony you talk about 46 percent of the NRG's coal capacity in Texas from 2017 to 2020 has been forwarded or sold higher than other areas of the country. How does that compare to the other generation sources like natural gas at NRG? And of course you have a nuclear plant in southeast Texas. Is one fuel source forward sold more than another and what plays into that?

Mr. MOSER. Yes. Oftentimes we tend to sell more of our coal rather than the gas because the coal tends to be at the money or in the money and so we have a large expected value with that. Our specific portfolio is a bit like a barbell. We have a lot of coal and nuke on one end which runs all the time and then we have a lot of old expensive steam gas which doesn't run very often so we tend not to hedge that as much and kind of use that to try and hedge against our retail exposure.

Mr. GREEN. What are some of the differences or difficulties in working in markets like ERCOT which lack capacity markets in other ISOs where the capacity revenues are established for a long-term forward basis?

Mr. MOSER. Well, it is easier in a market like PJM where you have a 3-year forward look at where the capacity prices are in terms of trying to determine the economic viability of your power plants.

Mr. GREEN. OK.

Mr. Chairman, that is my last question. But to follow my other colleague from the Houston area, when your house has six foot of water in it and you are so happy to have something to cheer about in the World Series.

So—but again in my last minute, how did NRG deal with some of the problems we had? I heard that for example the coal plants had to shut down because the coal was so wet that natural gas was still there and of course the nuclear plant continued to produce.

Mr. MOSER. The South Texas Project stayed online throughout Hurricane Harvey. We did run into problems at a couple of gas plants in the Greens Bayou which is in the northeastern corner got flooded. Cedar Bayou which is down near the ship channel was at one point we thought was going to get flooded. What we did was basically we brought three shifts of people in—cots, MREs—and prepared to ride out the storm, in effect.

But what you heard about Parish was absolutely correct. We did have at one point those coal plants—look, coal doesn't move up conveyors very well when it is liquid, it just kept running down, so we had to switch over to gas on those and we also brought the gas plants up. So I think at our low point we were in the 70 or 75 percent availability across our fleet in Texas. Limestone is far enough north that it wasn't impacted, but.

Mr. GREEN. OK. Thank you, Mr. Chairman.

Mr. UPTON. Mr. Griffith?

Mr. GRIFFITH. Thank you, Mr. Chairman.

Dr. Hildebrandt, Mr. Shimkus asked some questions earlier of Mr. Allen and Ms. Sidhom, and you heard their answers. In particular, Ms. Sidhom said if there were real problems on where their profit comes from, if it was negatively impacting consumers that you would be all over them. So I am going to give you a chance after you have heard their answers, what say you?

Dr. HILDEBRANDT. Well, we are calling for this, and actually the independent market monitor in PJM has been doing this for 3 years. So the market monitors whose job, who have the data and the information, whose job it is to look at these kind of things, in fact, are calling this out and providing the kind of analysis we are providing that is showing, you know, ratepayers are getting only a fraction of the dollars back from the FTR auction that they would otherwise get. So we are here. That is why I am here today.

Mr. GRIFFITH. What I am hearing from these folks, and I don't know a lot about this product so I am not taking sides, but what I am hearing is most everybody seems to think that this in the end makes sure the consumers have power and that they are getting a fair deal because these folks are making it more efficient.

And all they are doing from what I gather in interpreting their statements all they are doing in most cases is taking a portion of the savings that go to the consumers and that is where they make their profit by figuring out how to make the system more efficient. Do you disagree?

Dr. HILDEBRANDT. Yes, I absolutely disagree. Part of the issue here, we have two very different products being discussed here today. There is the virtual trading and I believe the benefits that Ms. Sidhom cited, I believe, is somebody's estimate of what virtual trading may have saved. That is very different.

Virtual trading is our trades between willing buyers and sellers. When the ISO clears the virtual that is cleared as part of an energy market which is a market between willing buyers and sellers. In that kind of market there can be value from that. However, in the FTR it is a very different product. It is an auction. It is not an actual market. They are auctioning these things off for 50 cents on the dollar.

In terms of the congestion revenues they are not providing any value in terms of, you know, they are siphoning off money which I think otherwise could be used to offset the costs of investments in the physical system, physical generating plants and physical infrastructure. So I think in that sense they are siphoning money out of the system without increasing efficiency in a way that ultimately can hurt reliability because it, you know, it does decrease, you know, kind of the money that can be used to improve the transmission system at a reasonable price to consumers.

Mr. GRIFFITH. So what do you think we should do to solve the problem as you see it?

Dr. HILDEBRANDT. Well, as I have said, I think we continue with the allocation of FTRs to load-serving entities. That includes direct access customers who, you know, are buying power through retail choice. But then stop the practice of having ISOs auction off FTRs backed by congestion revenues that otherwise go to load-serving entities. Stop that auction.

I think at that point my position is I think ICE, you know, you heard the gentleman describe how ICE it is a private company exchange. They provide long-term contracts for gas, for energy. You know, let the markets work. Again these gentlemen, Mr. Allen and

Mr. Moser can deal through ICE or bilaterally as far as selling a hedge at the appropriate price. That is what they are good at.

If policymakers really think ISOs, that the free markets can't work there and ISOs need to step in, then do that through an FTR market that only clears bids from willing buyers and sellers, so only if load-serving entity bid into that market to sell a hedge would they be exposed to having to sell an FTR.

Mr. GRIFFITH. All right. Now the dilemma that we have is we only get 5 minutes for questions. Mr. Allen, do you want to respond to any of the comments that were made? I probably won't have time for you, Ms. Sidhom, to get back in, but maybe somebody else will give you a minute.

Mr. ALLEN. I am glad we agree the virtuals are good. As far as the other stuff what I would advise, there are many market monitors throughout the country. Not all of them agree with the position that Dr. Hildebrandt has. Any as sort of analysis that FERC or you guys see about the value or the lack of value of FTRs coming from one market monitor or another, all I ask have it peer-reviewed. There needs to be some sort of peer review of anybody's analysis so that, you know, and market monitors have a tremendous amount of power and their analysis should be peer-reviewed. Thank you.

Mr. GRIFFITH. And I guess you all can appreciate that this is not our field or at least most of us up here, and we are just trying to get the facts to make sure the American consumers are getting the best deal that they can get. And with that I yield back.

Mr. UPTON. Mr. Johnson?

Mr. JOHNSON. Thank you, Mr. Chairman. I appreciate the opportunity. And thank the panel for being here this morning. You know, the FERC chairman, Neil Chatterjee, recently stated that one of the FERC's top priorities moving forward will deal with de novo reviews. As I am sure some of you are aware, the majority of the current court cases surrounding FERC's interpretation have gone on for years.

Mr. Allen, do you have any thoughts on how FERC should address this?

Mr. ALLEN. I would think that something along those lines, de novo review, is probably best left to the courts to decide. It is not, you know, I am not a lawyer, I am not, so I really can't offer you a good opinion on it other than I think it is probably, you know, let the courts figure it out.

Mr. JOHNSON. OK. Ms. Sidhom, do you have any thoughts?

Ms. SIDHOM. Absolutely. And I think that Chairman Chatterjee addressed that issue because FERC has lost on it multiple times in court now. We all want a robust enforcement program. That is really important for us. We need a cop on the beat. Nobody wants to participate in a market that is not being heavily policed, especially such a volatile market.

So, but what we really want is an efficient enforcement process and I think that the courts are making the absolute right decision on de novo review.

Mr. JOHNSON. OK, all right. Now maybe some of this has already been covered so I apologize if you feel we are being redundant here.

But we have heard from Dr. Hildebrandt regarding his thoughts on FTRs. Mr. Duane, what are your thoughts? Do you have any?

Mr. DUANE. You know, I think he is asking a question that is a legitimate question to ask. I think it is always the right question to ask, because at the end of the day as I said several times here this morning, and I don't mean this to disparage the financial participants, but they are there to serve a purpose and that is to make sure that the physical participants and, in particular, the consumer at the end of the day are getting the best deal possible out of these markets. That is what the fundamental design mission is.

And I think they can bring that benefit, but it has to be scrutinized. So the questions about the design of the market, they get pretty arcane when you are looking at the allocation of FTR revenues and I honestly don't think I can add anymore to that.

But the litmus I kind of use is if I see real risk management, if I see someone speculating and taking risk off the table, if I see them hedging, those are good types of financial transactions and people should be entitled to earn a return for providing those services and customers who pay a premium to get that insurance should feel comfortable about that.

Where I get more concerned is where there is arbitrage which should bring convergence among prices, but I don't see it actually happening. And that is really where I am coming from at PJM is a concern that at that point we do have a siphoning problem, we do have a hole in the bucket. I think FERC can separate the babies with the bath water and we can put in place rules to do that.

As far as the FTR market goes, I am just not at a point to say that is an example of one of those types of problems.

Mr. JOHNSON. OK. Mr. Shimkus began to address this as well. Monitoring Analytics, the independent market monitor for PJM, found in the most recent State of the Market Report that—and I quote. It is not clear in a competitive market why financial transmission right purchases by financial entities remain persistently profitable. In a competitive market it would be expected that profits would be competed away.

Do you agree with this statement, and if not, why not?

Mr. DUANE. No, I do agree with that statement. I am not sure it is a fair characterization of what is going on in PJM but, theoretically, yes, a competitive market should show over time a balance. And if there is a persistent asymmetry and what I think our market monitor is saying is that his observation over a period of time is that there is a persistent asymmetry and FTR traders have made money rather consistently.

I am not sure factually that is correct and I would want to look into that further, but if that is correct it is the kind of yellow flag that says maybe there is something structural in this complex market design that needs to be examined so that we do have a more symmetrical outcome.

Mr. JOHNSON. OK, all right.

Thank you, Mr. Chairman. I yield back.

Mr. UPTON. The Chair would recognize Mr. Flores.

Mr. FLORES. Thank you, Mr. Chair. And I appreciate this hearing and appreciate the witnesses participating today. It has been very informative.

One of the principal reasons we have hearings like this is so that we as policymakers can determine how involved we should be or not be in terms of trying to make sure that these markets work correctly. So my first question is this. What potential market regulatory reforms should Congress and FERC be considering in order to improve market benefits associated with financial trading?

So I would start with Ms. Sidhom. Can you share your thoughts? And try to do it quickly if you can.

Ms. SIDHOM. Yes, absolutely. We need long-term auctions just like you guys mandated in the Energy Policy Act of 2005. Those are integral to provide a forward price signal.

I also kind of want to address just a few comments that Mr. Hildebrandt made. California just put out a report negating a lot of the things that he said about FTRs, so its own ISO is not in agreement with him. They specifically say there are market design issues that they need to fix. So one of the reforms we really need is better outage scheduling and I touch on that in my testimony.

So, essentially, if I am a transmission owner and I don't plan out my outage, I should have to pay the costs that are incurred to the system for not planning out that outage. And New York employs that very practice and they save a lot of money. They have very few unplanned outages. That and technology reform, I think, really needs to occur.

I mean we have certain ISOs where some of their modules don't even work with like Chrome. They work with Internet Explorer but old versions of it, like we are really behind in technology.

Mr. FLORES. OK. Mr. Allen?

Mr. ALLEN. Real-time congestion hedge like exists in ERCOT, I would love to see that. We need to see that. It is necessary. It is essential for retail competition.

Mr. FLORES. OK. Mr. Moser?

Mr. MOSER. I would say there is plenty of things on the FERC docket already in terms of the different price formation dockets that they have been sitting on for years that we could move forward with immediately, some of the minimum offer price rules and et cetera. So there is plenty of stuff for them to do.

Mr. FLORES. OK. I would ask you to supplementally follow up and tell me what the top three or four are, if you would.

Mr. ALLEN. Happy to.

Mr. FLORES. Mr. Allen, also in your testimony you stated that competitive markets should be allowed to operate with minimal Government intervention such as out-of-market subsidies. If that intervention occurs, how is financial trading affected and do you have any recent examples?

Mr. ALLEN. If you have an out-of-market payment going to a certain class of generation assets it will distort market outcomes.

Mr. FLORES. Sure.

Mr. ALLEN. I think what is important is if there are certain externalities that are not being looked at that aren't being valued, whether it is carbon or reliability or so forth, I would ask that they be placed into the market so the market can respond to it and you don't distort market outcomes.

Mr. FLORES. OK.

Mr. Minzner, in terms of enforcement of financial trading you stated that financial markets inevitably move much faster than regulators. I think we all know that about this town. Is there anything Congress can do to ensure that FERC can remain nimble and to be able to evaluate new offerings of increasingly complex financial products?

Mr. MINZNER. So I think that is a great question, Congressman. I think largely it has been a success. I think Congress has, when problems have arisen in the energy markets, taken appropriate action—EPAct 2005 is a classic example of that—but also left it to the agency recognizing the complexity of these markets to adjust them as necessary as new products have developed.

It is not just that the markets are complex. They differ regionally. As you have heard, PJM is quite different from California and they are both very different from Texas. That has been a model that I think has been largely successful, but I really do think it is up to the agency to be constantly be reevaluating the structure of the market and the products that are available.

Mr. FLORES. Thank you, Mr. Chairman. I am going to yield back a minute to you.

Mr. UPTON. The Chair would recognize Mr. Barton.

Mr. BARTON. Thank you, Mr. Chairman, and you and Mr. Rush for this hearing.

I have not really followed the electricity markets for a number of years, so I am trying to get my hands around what a virtual transaction is. I don't know who to ask, I guess Mr. Moser. Are these transactions that are called virtual transactions, are they in and out the same day transactions?

Mr. MOSER. Yes. To the extent that the ISOs, if you put aside the FTR auctions, are running simply a day-ahead auction for power delivery tomorrow, then what the virtual transactions do is allow—so when I offer my plants in, you know, we will take Joliet 6 and we will say it is a $35 unit and we will offer that in to PJM in the market, and then if PJM needs $35 or higher power at that point I will get a commitment that I then have to run to for the next day and I will get paid 35 for it.

Mr. BARTON. Well, that sounds like a real transaction.

Mr. MOSER. That is a real transaction. But a virtual transaction would be if, you know, if a financial participant put in an offer at 35 and it looks just like generation in terms of going into the stack, it can get chosen and then basically what they have done is they have sold 35 in the day-ahead market. They are going to get $35 times however many hours times however many megawatts, and then when they don't deliver anything the next day because it is virtual—and this doesn't come as a surprise to the ISOs. The ISOs know what is virtual and what is real—then that settles against whatever the real-time price is.

So they basically have, they get paid 35 and then they are going to pay back to the ISO whatever the real-time average is for those same megawatts for that same timeframe, and it may be plus and it may be minus.

Mr. BARTON. So they have to deliver but they don't have to produce; is that——

Mr. MOSER. Well, in effect, they are taking the financial obligation of delivering, you know, no one expects virtuals to deliver so make no mistake there. There is no chicanery there. But they are basically a way of taking a position day-ahead against the real-time sell.

Mr. BARTON. But when a financial participant sells power at $35 a megawatt hour——

Mr. MOSER. Day-ahead.

Mr. BARTON [continuing]. For tomorrow delivery——

Mr. MOSER. Yes.

Mr. BARTON [continuing]. Sometime that day, do they take a position where they go in and buy, get a commitment to provide that power tomorrow at a lower price?

Mr. MOSER. Well, they may have, they may be doing that because they have a longer term position on that the ISO is not aware of. But generally speaking and in its simplest form, they have said I am willing to sell $35 power because I think the price tomorrow is going to be less than that and they are willing to take that risk on what that is for tomorrow's price.

Mr. BARTON. I guess the gentleman from California who kind of monitors this, are these virtual transactions helpful or hurtful to the real-time delivery of power and the pricing of power? You know, because California as we remember—some of us old-timers—10 or 15 years ago, you had the perfect market, you thought, and it all went to pot.

Dr. HILDEBRANDT. OK. Well, our market is working pretty well now, I think, Ms. Sidhom's comments notwithstanding. And so, you know, again you really need to differentiate. I have been talking today about financial transmission rights so, but you are asking me then about virtual.

Mr. BARTON. I am just trying to understand.

Dr. HILDEBRANDT. Sure.

Mr. BARTON. Because I don't think the public understands it.

Dr. HILDEBRANDT. We have them in our market. We think they can be beneficial to help kind of to help converge the day-ahead and real-time prices especially when you have a lot of renewables, so they can be beneficial. Unfortunately, they can be used also to manipulate the market. We have had cases like that. And specifically, you know, there are now cases, public cases, where that virtual trades have been used to manipulate prices that then increase payments that entities who have boughten firm transmission rights have.

So there is again have been some issues with cross-market manipulation. If you stop the auctioning of the firm transmission rights, I think then that would remove the issue of cross-market manipulation between the virtual bidding, which we are not proposing to get rid of in California, and can add value and again is based on bids from willing buyers and sellers as opposed to the firm transmission rights which are distinctly different.

Mr. BARTON. OK. Mr. Chairman, my time has expired. Thank you for the courtesy of allowing me to ask them.

Mr. UPTON. Yes. With that if no other Members have further questions we will adjourn. Thank you very much.

Oh, and we are going to put something in the record. I am going to ask unanimous consent to put in a letter from Monitoring Analytics into the record.

[The information appears at the conclusion of the hearing.]

Mr. UPTON. And with that, we stand adjourned. Thank you. Thank you.

[Whereupon, at 11:53 a.m., the subcommittee was adjourned.]

[Material submitted for inclusion in the record follows:]

PREPARED STATEMENT OF HON. GREG WALDEN

This is the eighth hearing in our committee's ongoing Powering America series. Today, we will explore the effects of financial trading in the Nation's wholesale electricity markets. I look forward to hearing from our panel of witnesses to better understand how financial transactions can improve the efficiency of the energy markets, as well as efforts to protect consumers from improper trading activity in energy markets.

Electricity is intrinsically different than other commodities, as electricity is produced and consumed instantly. Although energy storage technology is becoming more economically feasible, it is not yet cost-competitive at a utility scale. The inability to store electricity means supply and demand must constantly be balanced in real time. In turn, the instantaneous nature of electricity delivery and consumption can result in volatile energy prices.

Generators and load serving utilities can protect against price volatility by fixing the price of electricity for delivery at a future date by using various financial instruments such as a Financial Transmission Right (FTR). Today's hearing gives us the opportunity to learn more about how these FTRs and other virtual financial transactions fit into today's electricity markets.

Financial trading within electricity markets is complex and highly technical in nature. These financial products can improve the efficiency of electricity markets by increasing liquidity, mitigating market power, and improving the formation of energy prices, all of which can result in low-cost electricity for consumers.

We must balance these benefits against a history that includes bad actors who have utilized complicated trading strategies to engage in manipulation schemes in these energy markets. As I have said many times before, the American consumer always comes first. Consumers have come to expect competitive and efficient electricity markets that deliver affordable and reliable power.

PREPARED STATEMENT OF HON. FRANK PALLONE, JR.

Today we are examining the role financial trading plays in our Nation's electricity markets. This is a fairly technical, yet important aspect of the management of energy delivery, and it is certainly worthy of greater scrutiny.

Under the Federal Power Act, the Federal Energy Regulatory Commission, known as FERC, oversees electricity markets and the physical and virtual products traded within them. FERC specifically authorizes energy market participants' physical and virtual trading under tariff-based rules and protocols.

Financial tools, which include things like derivatives and financial transmission rights, can play a positive role in electricity markets. They do this by providing liquidity, by helping participants to hedge risk associated with a volatile commodity and by mitigating market power distortions. This makes for a more efficient market and, ideally, lower prices for consumers.

However, financial instruments can also create opportunities for bad actors to engage in market manipulation -and that is something that has been and continues to be of concern to me. I am particularly concerned about large banks and financial institutions that participate in the market purely to seek profit. Some of the biggest market manipulation cases taken by FERC involve big banks like JP Morgan Chase, which agreed to a $410 million settlement in 2013. Similarly, Barclays recently settled a market manipulation action brought by FERC for $105 million, and no longer engages in any trading transactions.

Electricity is a commodity unlike any other, both in physical terms and in terms of its importance to our everyday lives. While I do understand the benefits these financial tools can provide consumers, producers and transmitters of electricity, I remain skeptical of the role that pure traders and big banks play in this market. At a minimum, we must have strong standards and vigorous enforcement against market manipulation to ensure reasonable rates for consumers.

I want to thank our witnesses for participating today and yield the balance of my time.

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Monitoring Analytics

VIA EMAIL

November 27, 2017

Honorable Fred Upton
Chairman, Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515-6115

Honorable Bobby L. Rush
Ranking Member, Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515-6115

Re: Hearing of November 29, 2017, re role of Financial Participants in Wholesale Power Markets

Dear Sirs:

I am the Independent Market Monitor for the PJM wholesale power markets. I do not speak for PJM. The role of the independent market monitor, as defined by FERC and included in the PJM tariff, is to help ensure that the PJM markets are competitive by proposing market rules that incent competition, by monitoring for the exercise of market power and by reporting on the markets to regulators and market participants.

In an LMP market, the lowest cost generation is dispatched to meet the load, subject to the ability of the transmission system to deliver that energy. When the lowest cost generation is remote from load centers, the physical transmission system permits that lowest cost generation to be delivered to load. Prior to the introduction of LMP markets, firm transmission customers who paid for the transmission system through rates received the low cost generation.

After the introduction of LMP markets, financial transmission rights (FTRs) were introduced to permit the loads which pay for the transmission system to continue to receive those benefits in the form of revenues which offset congestion to the extent permitted by the transmission system. Financial transmission rights and the associated revenues were directly provided to loads in recognition of the facts that loads pay for the transmission system which permits low cost generation to be delivered to load. Another way of describing the result is that FTRs and the associated congestion revenues were directly provided to loads in recognition of the fact that load pays locational prices which result in load payments in excess of generation revenues which are the source of the funds available to offset congestion costs in an LMP market. Congestion is defined to be load payments in excess of generation revenues. Congestion revenues are the source of the funds to pay FTRs. In an LMP system, the only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to use FTRs, or an equivalent mechanism, to pay back to load the difference between the total load payments and the total generation revenues. The only way to ensure that load receives the benefits associated with the use of the transmission system to deliver low cost energy is to ensure that all congestion revenues are returned to load. Congestion revenues are defined to be equal to the sum of day ahead and balancing congestion. FTRs are one way to do that.

Effective April 1, 1999, FTRs were introduced with the LMP market, there was a real-time market but no day-ahead market, and FTRs returned real-time congestion revenue to load. Effective June 1, 2000, the day-ahead market was introduced and FTRs returned total congestion including day-ahead and balancing congestion to load. Effective June 1, 2003, PJM replaced the direct allocation of FTRs to load with an allocation of Auction Revenue Rights (ARRs). The load still owns the rights to congestion collected under this system, but the ARR construct allows load to either claim the FTRs directly (through a process called self scheduling), or to sell the rights in the FTR auction in exchange for a revenue stream based on the prices of the FTRs. Under the ARR construct, all of the FTR auction revenues should belong to the load and all of the congestion revenues should belong to those that purchase or self schedule the FTRs.

The current ARR/FTR design does not serve as an efficient way to ensure that load receives all the congestion revenues or has the ability to receive the auction revenues associated with all the potential congestion revenues. Total ARR and self scheduled FTR revenue offset only 86.5 percent of total congestion costs including congestion in the Day-Ahead Energy Market and the balancing energy market for the 2015/2016 planning period.

The goal of the ARR/FTR design should be to return 100 percent of the congestion revenues to the load. But the actual results fall well short of that goal. The current allocation of congestion revenue resulted in a total of $1,714.8 million in unreturned congestion revenue to ARR holders, and a 73.9 percent congestion offset, over the last seven planning periods.

Sincerely,

Joseph Bowring

Independent Market Monitor for PJM

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

ONE HUNDRED FIFTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE
2125 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515–6115
Majority (202) 225–2927
Minority (202) 225–3641

December 19, 2017

Mr. Wesley Allen
CEO
Red Wolf Energy Trading
3600 Camp Mangum Wynd
Raleigh, NC 27612

Dear Mr. Allen:

Thank you for appearing before the Subcommittee on Energy on November 29, 2017, to testify at the hearing entitled "Powering America: Examining the Role of Financial Trading in the Electricity Markets."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, January 9, 2017. Your responses should be mailed to Allie Bury, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Allie.Bury@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

Red Wolf
Energy Trading

Wesley Allen
CEO
Red Wolf Energy Trading
3600 Camp Mangum Wynd
Raleigh, North Carolina 27612

On Behalf of the Financial Marketers Coalition

January 9, 2018

The Honorable Fred Upton, Chairman
Committee on Energy and Commerce
Subcommittee on Energy
2125 Rayburn House Office Building
Washington, D.C. 20515-6115

Re: November 29, 2017 Hearing, Response to Additional Questions for the Record

Dear Chairman Upton:

Thank you for the opportunity to testify before the Subcommittee on Energy of the Committee on Energy and Commerce of the U.S. House of Representatives on Wednesday, November 29, 2017 at the hearing entitled, "Powering America: Examining the Role of Financial Trading in the Electricity Markets," and for the opportunity to address additional questions.

Attached are my responses to those additional questions per your letter dated December 19, 2017. Please accept my thanks to you, your fellow Subcommittee members, and your Staff for your time and consideration. Should you have any questions with regard to the attached, please do not hesitate to contact me.

Sincerely,

Wesley Allen

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

Additional Questions for the Record

The Honorable Fred Upton

1) **What potential market or regulatory reforms should Congress or FERC be considering in order to increase the market benefits associated with financial trading?**

Answer:

- Development of a Real-time congestion hedge in all markets
- Restructuring of the stakeholder process in the ISO/RTO markets to better protect minority interests
- Require data provided by ISOs and market monitors to stakeholders and FERC to be peer-reviewed
- Expedited completion of FERC's Notice of Proposed Rulemaking on Uplift Cost Allocation and Transparency

Product development. Wholesale markets benefit from a diverse toolbox of financial products available for all market participants to assist them in efficiently managing their positions. Financial products in ISO/RTO markets include virtual energy products, consisting of the Incremental Offer (INC) and the Decremental Bid (DEC), and virtual transmission products such as the Financial Transmission Right (FTR) and the Real-time Congestion Hedge.[1] Virtual products allow market participants to reflect in the Day-ahead market the conditions expected in Real-time, identifying system conditions so that market operators can make more efficient decisions. Forecasting system conditions with virtual products can help produce price outcomes that are closely aligned between the Day-ahead and Real-time markets, converging prices as well as unit commitment and dispatch. In other words, financial products assist with more accurate and granular price formation. Ultimately, price convergence and improved overall price formation in the wholesale markets produces lower prices to ultimate consumers.

Virtual transmission products are congestion hedging tools that can be utilized by any market participant to manage risk associated with forward contracting. Having this financial product available would particularly assist in hedging variable retail load. Congestion hedging products create benefits for both the market participant holding the forward contract and the market operator, by providing incentives to participate in the Day-ahead market, providing price transparency and efficiently pricing congestion, and signaling to the ISO/RTO when transmission capacity investments are needed. Congestion hedging mechanisms include the Up-to Congestion transaction and the Financial Transmission Right in PJM, as well as FTR equivalent products in MISO, NYISO and CAISO, and products similar to the UTC, including the Point-to-Point Product in ERCOT and products under development in MISO and NYISO. The purpose of long-term and short-term congestion products is to provide a hedge against real-

[1] We use the term "Real-time Congestion Hedge" to represent the name of the product in the Day-Ahead market which is a spread between two specified locations. In PJM, that product is called the Up-To Congestion ("UTC") product. In ERCOT, it is called the Point-to-Point ("P2P") product. In MISO, it is under development as the Virtual Spread Bid, and in NYISO it is under development as the Linked Virtual Transaction. Some also refer to the product as an Hourly Financial Transmission Right ("FTR").

time congestion. This product brings value to any entity purchasing transmission and potentially being subject to real-time congestion, providing a means by which to mitigate real-time congestion exposure. In turn, financial market participants serve as counter-parties to such entities, injecting competition, risk mitigation and liquidity.

To facilitate congestion hedging in a price sensitive manner, FERC and Congress should focus on the development of additional products, such as a Real-time congestion hedge, which would allow market participants to move congestion risk from the Real-time to the Day-ahead market when appropriate for managing risk. In addition to implementing longer-term FTRs, such as a ten year FTR auction, the addition of an hourly FTR, or Real-time congestion hedge, would allow market participants to hedge congestion in Real-time conditions.

I attach hereto a white paper prepared by XO Energy, LLC advocating for the development of an Hourly FTR in all markets. That white paper demonstrates that the expansion of virtual products in all ISO/RTOs to include an Hourly FTR, or Real-Time Congestion Hedge, would cost less than $1 million per ISO/RTO to implement and would yield tens of millions of dollars per ISO annually in increased market efficiency.

Stakeholder process. The primary issue that minority market participants, including financial market participants, face in the stakeholder process is the voting power of utilities. Entrenched utility interests have enormous strength in the stakeholder process because ISO/RTO rules employ weighted voting procedures, which distribute the number of votes based the number of subsidiaries within an organization. Further, stakeholders are broken into sectors with financial market participants grouped into large sectors, such as PJM's Other Supplier sector, where their votes are diluted by the sheer volume of organizations.[2] As such, vertically integrated utilities are able to exert a large amount of influence on stakeholder proposals because the number of votes per organization, and the number of organizations per sector in sectors other than the Other Suppliers sector, vastly outweigh the voting power of smaller companies. ISOs/RTOs must be cognizant of the power and influence of utilities in the stakeholder process, in conjunction with each stakeholder's duty to vote with their company's financial interests in mind. Many smaller companies do not have the staff to dedicate to closely monitoring multiple ISO/RTO stakeholder proceedings, whereas larger entities utilize teams of individuals to drive the process. While the Financial Marketers Coalition has sought to bridge this gap through stakeholder representation, the process is still challenging.

This combination can have the intended and unintended consequence of forcing proposals through the stakeholder process that may provide benefits for large utilities but are extremely adverse to market design. In a paper on electricity markets and virtual trading, two economists perfectly summed up the uplift debate in the PJM markets:

> The motivation for this paper arose from a vigorous policy debate about the merits of organized market designs in electricity markets. This debate reflects

[2] For example, there are 53 companies in PJM's Transmission Owners Sector, 40 companies in PJM's End User Customer Sector and 564 companies in PJM's Other Supplier Sector. This means one Transmission Owner's vote represents 0.025 % of the sector, while one Other Supplier's vote represents 0.0018 % of the sector.

> two distinct, but related difficulties that frequently confront policy makers. First, the potential for a more efficient market design to reallocate production from high-cost firms to lower-cost competitors will create a political incentive for market participants that stand to lose to oppose it.[3]

Weighted voting procedures allow utilities to set the course of stakeholder proceedings, which results in market reforms catered to utility interests with little regard for market outcomes, and as such, are often counter to consumers' best interests. PJM, for example, is required to implement market reforms arising from stakeholder proceedings, even if those reforms only benefit one sector, or are roundly opposed by one or two sectors. During the last Powering America hearing, Ranking Member Bobby Rush (D-IL) welcomed discussion on the market issues associated with ISO/RTOs beholden to incumbent utilities:

> As we will soon hear, Mr. Chairman, many consumer advocacy groups believe that the RTOs are too beholden to the utilities than they are trying to administrate. And consumers do not have a large enough seat at the table to make their voices heard. Many of these advocates argue that the whole process for reforming energy markets have become more and more complex, while at the same time consumer voices have been diluted to the point of being completely shut out. There also seems to be, a new consensus, Mr. Chairman, among today's witnesses, that FERC and DOE have become too tolerant of the RTOs' ability to shut out public interests, and participation, and policymakers must act to address this challenge.[4]

Congress and FERC should support ISO/RTO reforms that prevent market participants, particularly entire sectors of market participants, from being effectively shut out of the stakeholder process. Particular attention should be given to increasing protections for minority interests, and a review of each ISO/RTO's rules pertaining to sector-weighted voting.

In general, we question whether the stakeholder process should be the ultimate arbitrator of market design issues. It may not be in the best interests of consumers to have industry stakeholders holding the ability to change market design. The current practice places enormous pressure onto FERC as it must closely consider the actual impacts of a proposal, and not simply defer to the outcome of the stakeholder process. At the very least, best practices should guide market design issues, ideally aligning the ISO/RTO markets to some degree. After 20 years, we still have vastly different market structures across the United States. Interestingly, ERCOT, which is not regulated by FERC, has the most competitive market of all of the ISO/RTOs, even though it is the market which most recently moved from zonal to nodal pricing. Most

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[3] Mansur, E. and White, M., Market Organization and Efficiency in Electricity Markets at 41 (2012), *available at* http://www.dartmouth.edu/~mansur/papers/mansur_white_pjmaep.pdf (analyzing the benefits that PJM's expansion into the Midwest brought to regions previously not part of an organized market).

[4] Transcript of Powering America: Consumer-Oriented Perspectives on Improving the Nation's Electricity Markets at 3-4 (Oct. 7, 2017), *available at* http://docs.house.gov/meetings/IF/IF03/20171005/106470/HHRG-115-IF03-Transcript-20171005.pdf

importantly, the end goal of electricity markets should not be a market design that benefits stakeholders, but a design which facilitates and encourages competition.

Data and analysis. ISOs/RTOs, along with their market monitors, are currently able to provide data, analysis and conclusions to the public and to FERC without independent review from third parties. FERC relies on this data as a primary source of information to rule on proposed market reforms. In the past several years, ISOs/RTOs and their market monitors have questioned the value that financial marketers bring to the market, and have released data to FERC which can be construed as biased against financial market participants.[5] In contrast, several economists and market experts have performed studies and analysis which reflect the exact opposite, that financial market participants and virtual products bring benefits to the market significantly in excess of the cost of their participation. Even independent market monitors' opinions on financial market participation vary wildly among ISOs/RTOs, further highlighting the disparity between data and opinion. In order to preserve neutrality, FERC and Congress should require that data, opinions and conclusions released by an ISO/RTO or its market monitor should undergo a peer review process by independent market experts.

Uplift NOPR. In January 2017 FERC issued a Notice of Proposed Rulemaking on Uplift Allocation and Transparency in ISO/RTO markets. The Uplift NOPR is the culmination of years of work from FERC and market participants, including through FERC's price formation initiative, and if implemented, will significantly increase market efficiency, distribute market costs in an appropriate and equitable manner, and eliminate penalties that currently exist across many markets which disproportionately penalize efficient market behavior. Financial market participants strongly support the NOPR and believe that its reforms on uplift allocation and improved transparency in market operations and procedures will benefit all market participants. Now that FERC has a full quorum, it should focus on implementing this important rulemaking in all ISOs/RTOs as soon as possible.

2) In your testimony, you stated that competitive markets should be allowed to operate with minimal government intervention, such as out-of-market subsidies. If such intervention occurs, how is financial trading affected? Do you have any recent examples?

Answer:

- Subsidies based on fuel source and out-of-market credits distort price formation, preventing markets from functioning efficiently
- Congestion hedging products can produce cost savings by correctly identifying when transmission facility upgrades are necessary for reliability

When subsidies and other out-of-market credits are given to certain market participants or certain classes of market participants, those out-of-market actions distort market outcomes by decreasing the recipients' price responsiveness and price sensitivity. Out-of-market subsidies threaten competitive markets by suppressing prices, in both the capacity and electricity markets, sending

[5] At times, ISOs/RTOs, particularly PJM, have made significant market redesign proposals without any supporting data, or with only limited and questionable data. This is another issue to which FERC should be attuned.

signals to investors that there is little or no opportunity to enter the market and receive sustainable economic rents. Existing resources which are not receiving subsidies will experience eroding profit margins, leading to those resources exiting the market or requesting cost-of-service compensation. Subsidies threaten, and have the potential to irreversibly harm, competitive electricity markets and run counter to FERC's commitment to those markets.

Subsidies Based on Fuel Type: Any subsidy which allows one particular class of market participant to compete with an advantage vis-à-vis other market participants will provide preferential treatment and skew market outcomes. When subsidies are given to a class of market participants based on the fuel source that participant is utilizing, the subsidy impacts the market clearing price and the individual LMPs throughout the grid. The subsidy payments lead to otherwise uneconomic generation remaining in the market or the early retirement of otherwise economic generation. This leads to price distortions in both the energy and capacity markets, which ultimately leads to increased costs to consumers.

A recent report prepared by the Staff of the Department of Energy warned against the market distortions that could result from subsidies designed for limited types of resources.[6] The Staff Report cautioned that

> Interventions to promote specific fuel types—such as bailouts for coal and nuclear or mandates and subsidies for renewables—skew investment risk and can undermine incentives for reliability- enhancing behavior (e.g., a public intervention to finance pipeline expansion removes incentives for the private sector to invest in fuel security). Fuel-specific subsidies and mandates replace individual choice with collective choice. This one-size-fits-all approach to risk mitigation ignores variances in individuals' risk tolerances, results in high-cost risk mitigation, and creates perverse incentives for market participants by transferring risk and costs from the private to the public sector.[7]

As DOE Staff acknowledges, subsidies based on fuel type have the potential to result in the retention of thousands of megawatts of uneconomic generation, ultimately crowding out efficient generation resources that are then forced to compete on a skewed playing field. This is dangerous for competitive markets because it forces resource owners to focus on gaining subsidies rather than maximizing the efficiency of their units. As Joseph Bowring, the independent market monitor for PJM has observed, "[s]ubsidies are contagious," and these types of programs will mean that "[c]ompetition in the markets could be replaced by competition to receive subsidies."[8]

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[6] *See* Department of Energy, Staff Report to the Secretary on Electricity Markets and Reliability (Aug. 2017) ("DOE Staff Report"), https://energy.gov/downloads/download-staff-report-secretary-electricity-markets-and-reliability.

[7] *Id.* at 90-91.

[8] Statement of Joseph Bowring at 3, State Policies and Wholesale Markets Operated by ISO New England, Inc., New York Independent System Operator, Inc., and PJM Interconnection, L.L.C.,

Impact of Subsidies on Financial Trading: When placing transactions, financial participants are looking at the market signals that are sent from the ISO/RTO along with other factors. Taking a simplified example, if a generation unit's marginal cost to produce electricity is $30/MWh then we would expect that when the price is under that cost, the unit would either shut down or at the very least back down to minimum. Now assume that the same generator receives an out-of-market payment of $20/MWh. The impact of the out of market payment will result in the asset being able to produce electricity when prices are as low as $10/MWh, since the out-of-market payment will depress its marginal cost. This depression of wholesale prices will have a cascading impact across the footprint further distorting pricing and therefore distorting market outcomes. The electricity market does not recognize state borders. So the out of market actions of one state can have a drastic impact on the participants in another state.

3) In theory, the benefits associated with financial transactions appear to make the markets more efficient. However, quantifying these benefits versus the costs is not easy because there are so many variables in the markets. What is your best argument to convince me that the value you bring to the market is more than the value that you extract from it?

Answer:

- Noted economists have performed studies quantifying the benefits of financial transactions
- To effectively quantify the benefit of financial transactions all analysis must include a re-running of the Real-time market

Virtual trading brings specific benefits to wholesale markets, including convergence between the Day-ahead and Real-time markets, which helps to better preposition the Day-ahead market in preparation for the Real-time market. Convergence between the Day-ahead and Real-time markets is important because converged markets yield lower prices to consumers. By nature, energy markets are inherently volatile and risky because it can be hard for market participants to predict, in the Day-ahead market, what the Real-time market will look like. Financial market participants shoulder this risk on behalf of other market participants, allowing market participants to hedge the prices they will pay against the trades placed by a financial market participant. Financial marketers also bring needed liquidity and competition to markets, and introduce competition where otherwise none (or little) may exist.

The benefits of virtual trading have been touted by premier market experts and ISO/RTO market monitors. Dr. William Hogan has written extensively on the issue, summarizing the benefits that virtual transactions bring to the market as follows: "This virtual bidding promotes price discovery, allows market-based redistribution of risk, and offers an opportunity to price risk in the electricity market."[9] Similarly, Dr. David Patton, the market monitor for several ISO/RTOs,

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Docket No. AD17-11-000 (filed Apr. 25, 2017). *See also* DOE Staff Report at 14 (stating that economists have referred to the phrase "subsidies beget subsidies").

[9] HOGAN, W., *Electricity Market Design: Financial Transmission Rights, Up To Congestion Transactions and Multi-Settlement Systems* (July 16, 2012) ("2012 Hogan Study"), *available at* http://www.hks.harvard.edu/fs/whogan/Hogan_UTC_071612.pdf.

has argued for increased virtual bidding in MISO, including recommending the development of the virtual spread bid or real-time congestion hedge product,[10] because of the value that such trading brings to the market:

> [A]ctive virtual trading in the day-ahead market promotes price convergence with the real-time market, which facilitates an efficient commitment of generating resources. In addition, active virtual supply protects the market against attempts to raise day-ahead prices by economically withholding physical generation or making excess load or virtual load purchases.[11]

In terms of quantifying benefits, Dr. Frank Wolak and Dr. Akshaya Jhu looked at the CAISO market, both before and after the introduction of Convergence Bidding.[12] The study found that savings specifically came in three areas. First, the annual total cost of fossil fuel energy decreased by about roughly $70 million dollars per year in the year following the introduction of Convergence Bidding, through more efficient unit commitment. Second, the study found, Convergence Bidding resulted in a reduction of greenhouse gas emissions of approximately 2.8%, or between 537,000 and 650,000 pounds of emissions annually, again through better underlying unit commitment.[13] At the same time that year, the profits extracted from the market by entities trading Convergence Bidding was approximately $13 million in 2011 and $18 million in 2012.[14] While this study was done in the smaller CAISO market, it shows profound savings – with Convergence Bidding bringing value ***over four times greater*** than the cost of such trading in fuel costs alone, not including the value of avoided carbon emissions, and the longer term value of better pricing in the forward market to all market participants.

Another economist has performed analysis which accounts for many different variables in the markets, and his conclusions found that the benefit of virtual transactions far outweighed the

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[10] *See, e.g.,* 2012 State of the Markets Report for the MISO Electricity Markets at 25 (June 2013).

[11] 2008 State of the Market Report for the Midwest ISO at 41.

[12] JHA, A AND WOLAK, F, *Testing for Market Efficiency with Transaction Costs: An Application to Convergence Bidding in Wholesale Electricity Markets* (May 7, 2013) (emphasis added), *available at* http://web.stanford.edu/group/fwolak/cgibin/sites/default/files/files/CAISO_VB_draft_V8.pdf ("Wolak Study").

[13] This occurred through the pre-positioning of the Day-Ahead market, allowing more efficient units to run instead of the system operator calling on less-efficient units in the Real-Time market. Note that the dollar value of reduced greenhouse gas emissions is not included in the $70 million savings.

[14] California Independent System Operator, *Market Issues and Performance: 2011 Annual Report* at 87 (2011), http://www.caiso.com/Documents/2011AnnualReport-MarketIssues-Performance.pdf; California Independent System Operator, *Market Issues and Performance: 2012 Annual Report* at 109 (2012), http://www.caiso.com/Documents/2012AnnualReport-MarketIssue-Performance.pdf. We note that we refer only to the profits associated with internal Convergence Bidding, and do not include values associated with Convergence Bidding at the interties or in imports/exports.

costs. Dr. Scott Holladay, an economist with Yes Energy, studied the impacts on convergence in the PJM market from a decrease in UTC volumes. He found that convergence in PJM was reduced by approximately $1.52/MWh from September 8, 2014 through November 6, 2014.[15]

Quantifying the benefits of virtual transactions is challenging. To accurately capture the numerous market variables impacting the analysis, it is essential that all post-analysis must include data re-running the Real-time market. However, the only entities which have sufficient information to either re-run the market or simulate a market re-run are the ISO/RTOs themselves, and FERC's Division of Analytics and Surveillance ("DAS"). Neither has been willing to share data with third party economists. As such, an independent study, performed by FERC or the Congressional Budget Office utilizing the ISO/RTO data provided to FERC's DAS, would be very helpful.

The primary paper arguing against virtual transactions was published by Dr. John E. Parsons who, in conjunction with the FERC Office of Enforcement, performed an analysis of convergence bidding in the CAISO markets, questioning the value of virtual transactions and referencing certain virtual bidding as "purely parasitic."[16] Dr. Parsons' paper was highly skewed against virtual trading, seeking to find examples to prove that such transactions are not beneficial to competitive wholesale electricity markets. Dr. Parsons' analysis focused on ramping events in CAISO where virtual traders were consistently buying Day-Ahead energy and profiting from the ramping and scarcity pricing that occurs during the peak hours in California when load is rising quickly and renewables are simultaneously ramping offline. One of the primary fatal flaws of Dr. Parson's analysis was in not re-running the Real-Time results. As such, Dr. Parsons failed to answer the critical question of whether the virtual transactions that were committing additional resources were lessening the frequency and severity of the shortage pricing events. He also failed to quantify how frequently his asserted "parasitic" results were occurring, which is highly relevant because "parasitic" results in 1% of hours would be far less of a concern than "parasitic" results in 35-50% of hours. Regardless, virtuals were committing additional generation in the Day-ahead and making CAISO more reliable during scarcity events.

4) In your testimony you mentioned that Financial Market Participants are the only stakeholders working to ensure that electricity markets provide useful price signaling for short-term and long-term decision making.

Answer:

- Financial market participants profit when their transactions help converge the Day-Ahead and Real-Time markets
- Financial market participants help with prepositioning the Day-ahead market, risk mitigation and hedging, therefore reducing risk premiums which helps forward price formation.

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[15] Speaker Materials of Holladay, S., *Measures of Convergence In Up To Congestion Markets* at 8, Docket No. EL14-37-000 (issued Jan. 7, 2015).

[16] Parsons, J.E., *Financial Arbitrage and Efficient Dispatch in Wholesale Electricity Markets* (Feb. 2015), *available at* http://www.mit.edu/~jparsons/publications/20150300_Financial_Arbitrage_and_Efficient_Dispatch.pdf

- Long-term prices are derivative of short term prices. Financial participation helps get short-term prices right while reducing premiums.

Financial market participants profit from activity that converges Day-ahead and Real-time prices and reduces out-of-market actions that produce uplift, an extraneous cost which ultimately increases prices for customers. By converging prices financial participants help improve the commitment and dispatch of assets, making the electric grid more efficient and reliable. Ultimately all market participants are seeking to perform profit-driven actions because all market participants are driven by individual financial obligations and fiduciary duties.

Financial market participants are incentivized to produce efficient market outcomes because when they appropriately transact in a manner which brings Day-ahead and Real-time prices closer to one another, they profit. On the other hand, if they drive Day-ahead and Real-time prices further apart, they lose money. The market self-polices financial participants by rewarding those that enhance market efficiency and driving out of business those that don't.

For example, a financial participant might forecast that the peak hour prices should be at least $50/MWh on a particularly constrained day. When the Day-ahead market clears at $40/MWh, the financial participant will have cleared their bid. In the Real-time market, if the financial participant forecasted correctly and the price comes in at $60/MWh, the financial participant will have earned a profit. On the other hand, if the financial participant offered $30/MWh on the same constrained day, that participant has contributed to lower-cost supply offers, causing the Day-ahead to clear at $35/MWh. Incorrect forecasting in the Day-ahead could prevent generation from being committed in the forward market, causing prices in Real-time to spike as high as $80/MWh. The financial participant would sustain a significant loss, and the market would be made less efficient and more volatile.

The converse is true for other market participants who can derive profits from inefficiencies in the market, such as uplift payments for out-of-market dispatch.

a. Will you explain how financial market participants improve price signals and the effect that this has on industry investment decisions?

Financial market participants, and other types of market participants engaging in virtual transactions, send pricing signals through their activity. With virtual energy products such as INCs and DECs, they can send signals about where power may be priced too high in the Day-ahead market, such that more generation may be needed. With FTRs and Real-time congestion hedging products such as the UTC, financial market participants send pricing signals about congestion in the Real-time: where it is likely to be found, how frequently it occurs and what pricing results from high congestion. As noted in the staff memo in advance of the hearing, congestion typically occurs if there is not enough capacity on a given transmission line, if the line is out of service for maintenance or if an unplanned outage occurs. Persistent congestion demonstrates a potential issue which may need to be addressed with some level of investment. In other words, these signals show where and when transmission upgrade investments may be necessary, by signaling when existing facilities are no longer able to accommodate the congestion in a particular area. Financial products are another tool in the toolbox for the regional transmission planning process.

WHOLESALE ELECTRICITY MARKET REFORM

ENSURE THE AVAILABILITY OF A FINANCIAL DAY-AHEAD TRANSMISSION MARKET THAT WILL BE ALIGNED WITH THE EXISTING MONTHLY TRANSMISSION MARKET ACROSS ALL OF THE ISOS, RESULTING IN:

- **BILLIONS OF DOLLARS IN INCREASED EFFICIENCES;**
- **IMPROVED GRID RELIABILITY;**
- **FACILITATE COMPETITION ACROSS THE FERC-REGULATED ISOs;**
- **CONSUMER COST SAVINGS.**

January 2018

I. A Call for the Modernization of the Electric Grid.

Over the next two decades, it is anticipated that billions of dollars will be funneled into transmission and distribution investments in order to replace aging infrastructure and, in turn, enhance the resilience, reliability, safety and asset security of the electric grid. This is the primary focus of the Quadrennial Energy Review (QER): Energy Transmission, Storage, and Distribution Infrastructure, April 2015.

II. Deregulation Facilitates the Creation of Energy and Transmission Products.

Nearly twenty years ago, FERC commenced the deregulation of the wholesale electricity markets, allowing the unbundling of energy transactions. Unlocking access to the transmission system, while promoting competition, exposed market design challenges that required the creation of both a framework and operational capability to transact between generation and load.

Prior to deregulation, vertically integrated utilities owned generation and entered into long-term, price-inflated agreements on behalf of the load that they served. The competitive model required the replacement of the vertically integrated system with an efficient market design whereby generated energy and transmission could be independently transacted.

III. Energy and Transmission Products in the Forward Markets.

The right to acquire energy and transmission can be transacted years or months in advance. The acquisition of energy and transmission in the forward markets ensures that generated resources together with the right to transmit those resources from generation to load will be available years or months before they are needed to meet grid demand, safeguarding grid reliability and creating long-term price signals.

In the real-time market, the price of both energy and transmission can be far more volatile than expected in the forward markets. To address this volatility, economists recognized that the creation of a day-ahead market would facilitate a more economic dispatch of electricity in real time. By pre-positioning market operations on a day-ahead basis (versus months or years in advance), real-time generation and load could be more accurately predicted, resulting in greater price certainty and stabilization.

Since the introduction of the day-ahead market model in each of the ISOs, energy has been available for trading on a day-ahead basis. In addition to acquiring energy months or years in advance, trading in the day-ahead market offers increased granularity – the ability to assess and hedge against energy market price fluctuations in discrete periodic increments closer to real-time (e.g., on an hourly basis one day in advance).

Within PJM, the first ISO that was established, it was recognized that energy and transmission were fundamentally intertwined. In order to serve load in a price sensitive manner, the cost of transmission had to be considered as well. This recognition resulted in the expansion of PJM's day-ahead market to include the transacting of not just energy rights, but transmission rights, in order to better address the price volatility that occurred within PJM's footprint. Significantly, PJM's day-ahead transmission rights are only available in 3% of the market and have not been geographically expanded since their introduction.

Unfortunately, the ability to transact transmission on a day-ahead basis was not uniformly implemented by the other FERC-regulated ISOs. ERCOT, which is not under FERC jurisdiction, implemented a day-ahead market for both energy and transmission that is available across ERCOT's entire footprint. It is critical that these day-ahead transmission rights are available to the fullest extent across all ISOs in order to lead to more accurate price formation and market efficiency.

IV. The Changing Landscape of the Grid Requires the Expansion of the Day-Ahead Markets in all ISOs to include Transmission.

The modernization of the grid has been made all the more urgent by our pervasive dependence on a reliable supply of electricity. The principal challenges facing the grid: (i) revitalizing the aging infrastructure, which will require billions if not trillions of dollars in capital investments, and (ii) integrating variable energy sources, while maintaining stability in supply and price.

The sources of energy generation on the grid have changed dramatically. According to the U.S. Energy Information Administration, variable energy systems, including solar, wind, and hydropower, generated an unprecedented 523 million megawatt-hours of electricity in the United States in 2013, with variable generation on the rise. Furthermore, the retirement of coal-fired generators and, to a lesser extent, nuclear power plants, has precipitated our reliance on natural gas-fueled generators for a source of fully-dispatchable supply.

With the changing landscape of the grid, it is imperative that the day-ahead markets of all ISOs are expanded to include transmission. The transformation of the U.S. energy generation portfolio, while providing other potential benefits, will trigger a resurgence of price volatility if market participants are unable to hedge against price fluctuations in both energy and transmission in a more granular manner – that is, in the day-ahead market.

In order to improve market design efficiencies as well as effectively respond to a more dynamic generation portfolio, it is critical that the day-ahead market accommodate the transaction of both energy and transmission. Ensuring the availability of a financial day-ahead transmission market that is aligned with the existing financial monthly transmission market will improve market efficiency, reliability and price certainty by more effectively pre-positioning the markets on a day-ahead basis to support the economic dispatch of electricity in real-time.

V. Recommended Action.

Billions of dollars will be invested into the modernization of the electric grid, which will take decades to complete. In the near term, ensuring the availability of a financial day-ahead transmission market that is aligned with the existing financial monthly transmission market across all of the ISOs will facilitate market efficiency, reliability and the integration of a more diverse generation portfolio.

It is estimated that the implementation of a financial day-ahead transmission market, which can be included in the budgets of each of five ISOs for $500,000 - $1 million, respectively, with an estimated launch period of less than one year, will conservatively result in tens of millions of dollars per annum/ISO in increased market efficiencies.

* * * * *

Accordingly, FERC should encourage the ISOs to implement a fully-functional, financial day-ahead transmission market that will be aligned with the existing financial monthly transmission market. The implementation of a financial day-ahead transmission market will encourage more accurate price formation, which will improve market efficiency and performance, foster reliability, lower electricity prices, and facilitate the integration of variable renewable energy sources.

Senate and House provisions that were pending in the 2016 energy bill conference offered an opportunity to move forward on a day-ahead market for transmission, however, we understand that the proposed bill was subsequently abandoned. We strongly support the implementation of a more intensive and comprehensive bill.

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

ONE HUNDRED FIFTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE
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December 19, 2017

Dr. Eric Hildebrandt
Director of Market Monitoring
California ISO
250 Outcropping Way
Folsom, CA 95630

Dear Dr. Hildebrandt:

Thank you for appearing before the Subcommittee on Energy on November 29, 2017, to testify at the hearing entitled "Powering America: Examining the Role of Financial Trading in the Electricity Markets."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, January 9, 2017. Your responses should be mailed to Allie Bury, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Allie.Bury@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

California ISO

California Independent System Operator Corporation

January 9, 2018

Ms. Allie Bury
Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515
Allie.Bury@mail.house.gov

Dear Ms. Bury:

I appreciated the opportunity to appear before the Subcommittee on Energy on November 29, 2017 to testify at the hearing entitled "Powering America: Examining the Role of Financial Trading in the Electricity Markets."

Attached are responses to the additional questions provided in writing by the Honorable Fred Upton via letter dated December 19, 2017.

Sincerely,

[redacted]

Eric Hildebrandt, Ph.D.
Director of Market Monitoring
Department of Market Monitoring
California Independent System Operator
[redacted]

Attachment

Response to Additional Questions for the Record

Eric Hildebrandt, Ph.D.
Director, Department of Market Monitoring
California Independent System Operator Corporation

Committee on Energy and Commerce
Subcommittee on Energy
United States House of Representatives
January 9, 2018

The Honorable Fred Upton

1. ***In your testimony, you state that market design flaws associated with Financial Transmission Rights (FTRs) is costing ratepayers over $400 million a year. Why does every RTO and ISO have this flaw and what is your proposed solution?***

A review of congressional legislation and related proposals and decisions by the Federal Energy Regulatory Commission (FERC) clearly shows that FTRs were created for the express purpose of benefiting customers by allowing load serving entities (LSEs) to hedge power purchases made by LSEs on behalf of their customers. All ISOs/RTOs do this by allocating FTRs directly to load serving entities (LSEs).[1] Moreover, prior proposed rules and orders by FERC clearly indicate that auctions for FTRs were initially developed and envisioned only as a means for providing a secondary market in which LSEs could choose to sell any FTRs they were allocated *if they felt this was economic to do so*. However, all ISOs/RTOs have gone beyond the initial intent and requirements for FTRs established by Congress and the FERC by establishing auctions in which

[1] Some ISOs/RTOs allocate LSEs auction revenue rights (ARRs), which can be directly converted into FTRs and are essentially equivalent to FTRs.

ISO/RTOs auction off additional FTRs backed by congestion revenues that would otherwise be refunded to transmission ratepayers.

The Commission addressed FTRs in 2002 as part of its initial Standard Market Design (SMD) proposal, which stated:

> To provide the price signals needed to manage congestion, the Independent Transmission Provider will be required to operate a day-ahead and real-time market for energy. To provide customers with a mechanism for achieving price certainty under the new congestion management system, we also propose to require that customers be given Congestion Revenue Rights for their historical uses that protect against congestion costs when specific receipt and delivery points are used.[2]

FERC's initial SMD proposal included a requirement for ISOs/RTOs "to offer Congestion Revenue Rights for all of the transmission transfer capability on the grid," [3] and included a "preference for the auction of Congestion Revenue Rights," but would have allowed "regional flexibility for a four-year transition period in determining whether to allocate Congestion Revenue Rights to existing customers or auction rights such that revenues are allocated to existing customers to hold them financially harmless [to the financial consequences of congestion in markets based on locational marginal pricing]. [4] FERC's initial 2002 proposal also indicated that the Commission believed it is important that ISOs/RTOs facilitate an active secondary market for CRRs by holding an auction in which "buyers and sellers would submit bids that specify the type of Congestion Revenue Rights desired to be bought or sold .." [5]

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[2] Remedying Undue Discrimination, Through Open Access Transmission Service and Standard Electricity Market Design, July 21, 20012, Notice of Proposed Rulemaking, Docket No. RM01–12–000, (2002 Standard Market Design Proposal) ¶ 111.

[3] 2002 Standard Market Design Proposal, ¶237

[4] 2002 Standard Market Design Proposal, ¶15

[5] 2002 Standard Market Design Proposal, ¶252

In 2003 FERC issued a Standard Market Design White Paper in response to comments and concerns submitted on its initial SMD NOPR. This paper again indicated that "RTOs and ISOs that use locational pricing to manage congestion would be required to make Firm Transmission Rights (FTRs) available to customers ....[to] protect customers from the costs of congestion",[6] but went on to clarify that ISOs would not be required to auction FTRs:

> The Final Rule will eliminate any requirement that FTRs be auctioned. We will, instead, look to regional state committees to determine how such rights should be allocated to current customers based on current uses of the grid. Varying approaches to FTR allocation need not create "seams" with neighboring regions.[7]

FERC's 2003 whitepaper also clarified that rather than requiring ISOs to auction off additional FTRs, ISOs would be required to operate a secondary market for the purpose of allowing load serving entities that were allocated FTRs to voluntarily sell their FTRs if they so choose:

> There would be no requirement to auction these FTRs either initially or after a transition period ..... Once the initial allocation of FTRs is completed, the RTO or ISO must operate a secondary market for holders of FTRs to voluntarily sell their FTRs to others.[8]

Although FERC's standard market design rulemaking proposal was terminated and never adopted, the Energy Policy Act of 2005 added a new section to the Federal Power Act which again clarified that requirements placed on ISOs/RTOs relating to FTRs were intended to pertain only to the service obligations and power contracting needs of load serving entities' – and were not required for the benefit of financial traders or hedging by power producers:

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[6] White Paper on Wholesale Power Market Platform, April 28, 2003, p.10.

[7] White Paper on Wholesale Power Market Platform, p.5

[8] White Paper on Wholesale Power Market Platform, Appendix A. p.9

> The Commission shall exercise the authority of the Commission under this Act in a manner that facilitates the planning and expansion of transmission facilities to meet the reasonable needs of load-serving entities to satisfy the service obligations of the load-serving entities, and enables load-serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs.[9]

In Order 681 the Commission clarified once again that FTRs were intended to provide a way for load serving entities who purchase electricity (rather than entities that sell electricity) to hedge congestion costs.

> The primary objective of guideline (1), consistent with section 217(b)(4), is to allow a load serving entity to obtain a long-term firm transmission right for purposes of hedging congestion charges associated with delivery of power from a long-term power supply arrangement to its load. We will adopt guideline (1) without modification. [10]

Order 681 also made it abundantly clear that requirements relating to FTRs established through the Energy Policy Act of 2005 applied only to the allocation of FTRs to load serving entities – and does not require the sales of additional FTRs by an ISO through an auction.[11]

As illustrated above, all requirements in Federal legislation and related to FERC decisions concerning FTRs are designed to provide hedges to load serving entities who purchase energy. These requirements were not established to meet the desires of financial entities or generation owners. Thus, even if some FTRs are used by generation owners as hedges for sales of power, it is unjust and unreasonable to ask customers of load serving entities who pay for the cost of the nation's transmission system to continue to lose $400 million to $600 million per year to subsidize any such

[9] Pub. L. No. 109-58, § 1233, 119 Stat. 594, 958

[10] Order No. 681, Final Rule, July 20, 2006, ¶116 at p. 66.

[11] e.g. see Order No. 681, Final Rule, July 20, 2006, ¶361 to ¶393 at pp.172-190.

hedges. Moreover, analysis shows that the bulk of FTRs purchased in auction are purchased by financial entities rather than by generation owners that might use these as hedges.

ISOs/RTOs do not need to auction FTRs for generation owners or energy traders to gain access to physical transmission or to hedge price risks associated with wholesale energy contracts and trading. As with other commodities, market participants and financial entities are free to develop and trade price swap contracts. In fact, this type of free market – with trades between willing buyers and sellers – is what is needed to price such price swaps most efficiently and fairly. If policy makers believe it is beneficial to wholesale electricity markets and consumers for ISO's to facilitate such financial price swaps, then ISO's should do this through a market for FTRs that is cleared and settled based on bids and offers from willing buyers and sellers.

In financial terms, all FTR auctions involve the sale of financial hedging contracts that are backed by transmission ratepayers which are auctioned off by ISOs/RTOs at a $0 offer price. This market design essentially forces transmission ratepayers to sell these financial contracts as "price takers" in the auction. This basic market design flaw can only be completely and effectively addressed by replacing these auctions with a market for financial hedging contracts that is based entirely on bids submitted by willing buyers and sellers.

A report posted on our website provides a discussion of market-based options through which energy generators, traders and financial entities can buy and sell financial instruments that allow hedging of congestion costs – without requiring the nation's transmission ratepayers to incur the enormous financial losses they are incurring as a result of FTR auctions currently operated by the nation's largest ISO's/RTOs.[12]

The Honorable Fred Upton

2. ***I understand that sometimes the revenue paid out to Financial Transmission Right (FTR) holders is greater than the revenue generated by FTRs, resulting in a revenue shortfall. When this occurs, where does the money come from to cover the shortfall?***

In the nation's largest ISO/RTOs, the revenue paid out to entities that purchase FTRs in auction is consistently and systematically greater than the revenue generated by the sale of FTRs in these auctions. FTRs are paid out of congestion revenues collected by the ISOs/RTOs. Any congestion revenues not paid out to FTR holders are refunded to LSEs. Therefore, the difference between auction revenues and congestion revenue paid out to FTRs purchased in the auction represents a direct loss to load serving entities. While the LSEs get the auction revenue, they consistently give up much more in congestion revenue in return.

In her testimony on behalf of the Power Trading Institute, Ms. Noha Sidhom notes that a "good analogy" of transmission congestion charges is the higher tolls collected for use of a highway during rush hour.[13] Using this analogy, FTR auctions are analogous to a state government auctioning off the rights to the tolls collected on public

[12] *Market alternatives to the congestion revenue rights auction,* Department of Market Monitoring, California Independent System Operator, November 27, 2017. http://www.caiso.com/Documents/Market_Alternatives_CongestionRevenueRightsAuction-Nov27_2017.pdf

[13] Noha Sidhom, CEO of TPC Energy, LLC on behalf of the Power Trading Institute Subcommittee on Energy Committee on Energy and Commerce U.S. House of Representatives Hearing: Examining the Role of Financial Trading in the Electricity Markets November 29, 2017, p.2. http://docs.house.gov/meetings/IF/IF03/20171129/106663/HHRG-115-IF03-Wstate-SidhomN-20171129.pdf

highways by the state for a future time period to the highest bidder. However, in this analogy, the revenues received by the state from this auction are consistently far below the tolls collected by the state. Thus, without such an auction, the toll revenues collected by the government would offset a much greater part of the cost to the state's taxpayers who paid the full cost of building the highway.

In response to the question of where the money to pay FTRs comes from, Ms. Sidhom also stated that "the value of allocated rights [to LSEs] is determined in the FTR auction," and that FTR auctions save money for consumers since "they provide an accurate price for the contracts that are allocated to transmission customers representing consumers." [14] This is simply not the case in any ISO/RTO. FERC originally envisioned that ISOs could conduct FTR auctions as one way for LSEs to voluntarily sell any allocated FTRs if they felt this was economically advantageous for them to do so. However, there is no link whatsoever between the economic value received by LSEs from allocated FTRs that they retain and the price of the additional FTRs sold by an ISO in an auction. On the contrary, LSEs retain their allocated FTRs and receive FTR payments that are much greater than the price of FTRs sold in the auction.

Ms. Sidhom also contends that "basically, this is a public auction of excess capacity."[15] Again, this is simply not the case. As Ms. Sidhom acknowledged, FTRs are purely financial price swap contracts, and provide no physical access or rights to the transmission grid. Congestion revenues are only generated when congestion occurs on

[14] Noha Sidhom, p.7-8

[15] Noha Sidhom, p.7.

the transmission system when there is not excess capacity. And if additional FTRs were not auctioned off by the ISO, all of these congestion revenues would be allocated back to LSEs which pay for the full cost of the transmission system through the Transmission Access Charge (TAC).

In the CAISO, the financial impact of FTRs auctioned off by ISOs on transmission ratepayers occurs through the Congestion Revenue Rights balancing account.[16] Table 1 below shows totals for this settlement account for 2017. As shown in Table 1, total congestion revenues in the CAISO totaled $357 million in 2017. A net total of about $279 million in CRR payments were made to LSEs receiving CRRs through the allocation process.[17] The CAISO's CRR auction generated about $83 million in revenues from non-LSEs, but resulted in CRR payments of about $184 million to these non-LSEs – resulting in a loss of about $100 million to LSE's.

Table 1. CAISO Congestion Revenue Rights Account, 2017
(Millions of dollars)

	With CRR auction	Without CRR auction
Day-ahead market congestion rent	$357	$357
Net CRR payments to LSEs*	($279)	($279)
Net CRR auction revenues from non-LSEs	$83	
Net payments to non-LSE auction CRRs	($184)	
Account surplus/deficit	($22.6)	$78

As shown in Table 1, this resulted in a deficit in the CRR balancing account of about $22 million, which is charged to LSEs based on their pro rata share of load and

[16] As noted in my November 29 testimony, FTRs are called Congestion Revenue Rights (CRRs) in the CAISO.

[17] This net total includes payments to allocated CRRs, net payments to LSE auction CRRs, and net auction revenues paid by LSEs

exports. However, if no additional CRRs were auctioned off by the CAISO, a total of $78 million would be credited back to LSEs. Thus, as a result of the auction, LSEs received an additional charge of $22 million rather than receiving a credit back of $78 million. This represents a loss of about $100 million to LSEs in the CAISO in 2017 as a result of additional FTRs auctioned off by the CAISO.

2a. How often does this occur and on what scale?

The $400 million per year cited in my testimony represents our estimate of the lower end of the costs being imposed on the nation's electric transmission ratepayers through FTR auctions. Analysis from Stanford University's Economics Department places this figure at $600 million per year.[18] These analyses show that ratepayer losses from sales of FTRs by ISOs represent a very systematic and consistent long term trend, and have now occurred each year for over almost a decade.

In the CAISO, transmission ratepayers have lost money on FTRs sold in the CAISO's auction every year since the auction began in 2009. Losses have totaled over $756 million or an average of $80 million per year. [19] In 2017 losses to transmission ratepayers from FTRs sold at auction totaled over $100 million. Similar results have been consistently reported based on data from the nation's other three largest ISOs and RTOs:

[18] paper

[19] These data have been updated since my November 29 testimony to include results through the end of 2017.

- Research from the Stanford University Economics Department shows that in the New York ISO ratepayer losses were $938 million from 1999 to 2016, or almost $60 million per year.[20]
- In PJM, ratepayers have lost over $1.18 billion from 2011 through September 2017 according to PJM's Independent Market Monitor. Financial entities have received about $170 million per year in FTR profits.[21]
- In the Midcontinent ISO (MISO) for the 2010-2011 through 2016-2017 planning periods, on average only about 80 percent of the day-ahead market congestion rent was received by transmission ratepayers.[22] As explained in earlier DMM reports, this implies that transmission ratepayer losses in the FTR auction were equal to about 20 percent of day-ahead congestion rents for the period.[23] Day-ahead congestion rent averaged about $790 million from 2011 through 2016.[24]

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[20] Leslie, Gordon "Why do transmission congestion contract auctions cost ratepayers money? Evidence from New York" November 14, 2017, downloaded 11/17/2017: http://www.web.stanford.edu/~gwleslie/index_new_files/Leslie_JMP20171114.pdf

[21] Monitoring Analytics, *2016 State of the Market Report for PJM* p. 553: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec13.pdf

Monitoring Analytics, *2017 Quarterly State of the Market Report for PJM: January through December* p. 559: http://www.monitoringanalytics.com/reports/PJM_State_of_the_Market/2016/2016-som-pjm-sec13.pdf

[22] Midcontinent ISO *ARR/FTR Transmission Customer Metric May 11, 2017*: https://www.misoenergy.org/Library/Repository/Meeting%20Material/Stakeholder/MSC/2017/20170511/20170511%20MSC%20Item%20XX%20ARR%20FTR%20Transmission%20Customer%20Metric%20April%202017%20Update.pdf

[23] Department of Market Monitoring *Shortcomings in the Congestion Revenue Right Auction Design* p.6: https://www.caiso.com/Documents/DMM-WhitePaper-Shortcomings-CongestionRevenueRightAuctionDesign.pdf

[24] MISO day-ahead congestion rent data from Potomac Economics *2016 State of the Market Report for the MISO Electricity Market* p.50; Potomac Economics *2014 State of the Market Report for the MISO Electricity Market* p.52; Potomac Economics *2012 State of the Market Report for the MISO Electricity Market* p.46. Reports available at: https://www.misoenergy.org/MARKETSOPERATIONS/INDEPENDENTMARKETMONITOR/Pages/IndependentMarketMonitor.aspx

This data indicates that transmission ratepayers in MISO have consistently suffered large losses from the FTR auctions, between $100 million and $200 million per year.

The Honorable Fred Upton

3. You testified that financial instruments are essentially price swap contracts and that unlike such contracts for other commodities, FTRs sold in electricity markets are not cleared and settled based on bids from willing buyers and sellers, but instead auctioned off by market operators. Can you explain in further detail why this is the case?

As explained in response to Question 1, a review of congressional legislation and related proposals and decisions by the FERC shows that FTRs were originally meant to provide a way for LSEs to hedge their electricity purchases. This can be accomplished by allocation of FTRs to LSEs and does not require an auction of additional FTRs by the ISO.

We do not know exactly why all ISOs and RTOs adopted FTR auctions. Dr. William W. Hogan developed the theory of using FTRs (which he originally called network contracts) to allocate congestion rents in 1992.[25] In this paper, Dr. Hogan expresses the belief that FTRs define rights that are amenable to market trading. Dr. Hogan writes that "... the contract network framework can support the allocation of transmission capacity rights through a competitive bidding system." Dr. Hogan's paper also seems to assume the auction would be competitive with prices equaling the expected spot market congestion prices.[26] The policy that subsequently established

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[25] Hogan, William W. *Contract Networks for Electric Power Transmission: Technical Reference*, 1992, https://sites.hks.harvard.edu/fs/whogan/acnetref.pdf

[26] Hogan, pp.38 and 42.

FTR auctions appears to have been influenced by this narrative initiated by Dr. Hogan — if the ISO can get the FTR transmission model exactly right and if the auction market is competitive, then auction revenues should equal the expected payouts.

However, the literature and policy proceedings on FTRs reflect very little recognition of the fact that the auction obligates transmission ratepayers to sell financial swaps regardless of the sale price. Similarly, the risk that this creates for ratepayers to suffer large losses from FTR auctions does not appear to have been widely recognized. In the MISO and NYISO, neither the ISO nor its market monitor have reported the information necessary to directly quantify these losses. But the financial risk and obligations placed on ratepayers by FTR auctions and the discrepancy between FTR auction prices and payments is now very evident.

One factor underlying the flawed nature of auctioning FTRs backed by transmission ratepayers is the complexity of FTRs as a financial product. As explained in a 2014 expose on FTRs in the *New York Times*:

> Across the nation, investment funds and major banks are wagering billions on [transmission congestion contracts], as they chase profits in an arcane arena that rarely attracts attention... The utilities and power companies suggest they cannot win against trading outfits that employ math specialists, often called `quants,' to spot lucrative opportunities. With transmission contracts, there are tens of thousands of tradable combinations.[27]

As explained in academic research from Stanford University, the complexity of FTRs as a product creates a major barrier to entry and competition in the FTR auction:

> Anecdotes suggest a major barrier to eroding total trading profits could be the cost for new entrants to develop a technology that can identify successful trading strategies in these auctions. The auctions are notoriously complex, where TCC

[27] "Traders Profit as Power Grid is Overworked" *The New York Times* August 14, 2014: https://www.nytimes.com/2014/08/15/business/energy-environment/traders-profit-as-power-grid-is-overworked.html

> payouts and the auction allocations are determined in part by physical transmission constraints in the electric network. Successful firms consistently update their models and aggressively enforce non-disclosure agreements with ex-employees. The persistence of total trading profits over 16 years and the protection firms place on their trading technologies suggest that if regulators wish to reduce the transfers of wealth from electricity customers to TCC holders, waiting for future trader entry may not achieve this goal. Policy modifications may be required ... such as eliminating the markets or restricting the set of products offered.[28]

This research also makes the important point that the large number of potential products and product combinations in the FTR auction can dissipate effective market liquidity.

A detailed discussion of the fundamental economic flaws underlying the auctioning of FTRs are provided in a recent report by the California ISO's Department of Market Monitoring.[29] This report identifies a variety of factors that are likely to help explain the very poor performance of the CRR auction from the perspective of ratepayers. These include:

- FTRs are not consistently defined products in both the auction and day-ahead market. A substantial body of economic literature exists that explains how this condition leads to underpricing in auctions for a variety of commodities.[30]

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[28]Leslie, Gordon "Why do transmission congestion contract auctions cost ratepayers money? Evidence from New York" November 14, 2017, p. 4. http://www.web.stanford.edu/~gwleslie/index_new_files/Leslie_JMP20171114.pdf

[29] *Problems in the performance and design of the congestion revenue right auction*, Department of Market Monitoring, California Independent System Operator, November 27, 2017. http://www.caiso.com/Documents/DMMWhitePaper-Problems_Performance_Design_CongestionRevenueRightAuction-Nov27_2017.pdf

[30] For example, see: Athey, Susan, and Jonathan Levin. 2001. "Information and competition in US Forest timber auctions." Journal of Political Economy, p. 377 at http://web.stanford.edu/~jdlevin/Papers/Skewing.pdf; and Agarwal, Nikhil, Susan Athey, and David Yang. 2009. "Skewed Bidding in Pay Per Action Auctions for Online Advertising" The American Economic Review at http://economics.mit.edu/files/10630.

- FTR auction participants can profit from better information on differences in the way CRRs are defined in the auction versus the day-ahead market – without increasing efficiency or adding any value to ratepayers or other market participants.
- LSEs representing transmission ratepayers face significant limitations to bidding in FTR auctions.
- Buyers do not have an incentive to bid auctioned FTRs up to their expected value.

These represent fundamental flaws that cannot be eliminated under the current FTR market design. These flaws cannot be removed or fixed by simply improving the accuracy of the transmission network model used in the FTR auction, as some suggest. These flaws can only be entirely and effectively addressed by replacing the current auction design with either a bilateral market or centralized market for price swaps or a voluntary market for price swaps between willing buyers and sellers. However, the option of a centrally run market administered by ISOs/RTOs should only be pursued if policymakers believe that the benefits of facilitating price swaps warrant or require intervention by the ISOs/RTOs, rather than allowing price swaps to occur through private mechanisms as occurs with other commodities.

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

ONE HUNDRED FIFTEENTH CONGRESS

Congress of the United States

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December 19, 2017

Mr. Max Minzner
Partner
Jenner & Block LLP
1099 New York Avenue, N.W.; Suite 900
Washington, DC 20001

Dear Mr. Minzner:

Thank you for appearing before the Subcommittee on Energy on November 29, 2017, to testify at the hearing entitled "Powering America: Examining the Role of Financial Trading in the Electricity Markets."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, January 9, 2017. Your responses should be mailed to Allie Bury, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Allie.Bury@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

1099 NEW YORK AVENUE, NW SUITE 900 WASHINGTON, DC 20001-4412

JENNER&BLOCK LLP

Max Minzner
[redacted]

January 8, 2018

The Honorable Fred Upton, Chairman
Subcommittee on Energy
House of Representatives
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Chairman Upton:

Thank you for your December 19, 2017 letter containing additional questions for the hearing record on "Powering America: Examining the Role of Financial Trading in the Electricity Markets."

My responses to the questions are enclosed. I want to thank you again for the opportunity to appear before the Subcommittee on Energy on November 29, 2017.

Sincerely,

[redacted]
Max Minzner

cc: The Honorable Bobby Rush, Ranking Member
Subcommittee on Energy

Attachment Enclosed

Max J. Minzner
Partner, Jenner & Block LLP
Responses to Questions for the Record

Committee on Energy and Commerce
Subcommittee on Energy and Power
United States House of Representatives
January 8, 2018

<u>The Honorable Fred Upton</u>

1. **In terms of enforcement of financial trading, you stated that *"financial markets inevitably move much faster than regulators."* Is there anything that Congress can do to ensure that FERC can remain nimble and be able to evaluate new offerings of increasing complex financial products?**

Broadly speaking, FERC has the statutory authority it needs to regulate the financial products in its markets. The Federal Power Act provides the Commission multiple options to intervene when necessary. First, products generally cannot be traded in the organized markets unless FERC approves tariff provisions that permit the transactions. FERC can and should carefully scrutinize new offerings to ensure that they improve the functioning of the market. Second, FERC can regulate the transactions after they occur by bringing appropriate enforcement actions or changing the market rules. Third, market participants can bring complaints if they identify a flaw in the market rules. These tools, if used appropriately, should be adequate for the agency to carry out its mission. Of course, Congress should ensure that the Commission has adequate resources to carry out its mission.

2. **In your testimony, you stated that financial traders should <u>not</u> be treated differently just because they are financial, rather than physical, participants in the jurisdictional markets. Can you elaborate on this point?**

Market participants should be treated equally and allowed to engage in market transactions on a level playing field. Differences in regulatory requirements should depend on risk-based policy considerations and should not vary based on the type of market participant. Enforcement actions generally should not turn on whether an entity is a physical or financial participant in the market. Instead, FERC should focus on the conduct of the enforcement target when bringing an action.

The Honorable H. Morgan Griffith

1. **As the former General Counsel of FERC and a Special Counsel in FERC's Office of Enforcement, you've likely seen instances of improper conduct by traders of financial products. Now that you are no longer with the Commission, can you provide a frank assessment of FERC's abilities to detect and investigate improper activity involving financial trading?**

FERC is generally well-equipped with the tools needed to investigate and bring enforcement actions in cases involving financial trading. FERC has prioritized the detection of improper conduct by developing new algorithmic screens and working to develop other analytic tools. These cases are inherently difficult, though, when they involve conduct that crosses jurisdictional boundaries. For example, FERC regulates physical energy products while the CFTC regulates the financial derivatives that take their value from physical energy. Traders can thus take simultaneous positions in linked physical and financial products, only one of which is regulated by FERC. Enforcement actions in these cases necessarily involve close coordination between sister federal agencies. FERC has historically worked to improve that coordination and should continue to do so.

The Honorable Bill Johnson

1. **FERC Commissioner Neil Chatterjee recently stated that one of the Commission's priorities moving forward will surround "de novo review." As you may know, the majority of current court cases regarding FERC's interpretation have gone on for years. Mr. Mizner, do you have any thoughts on how FERC should address this issue?**

The agency is currently litigating the scope of federal court review of enforcement actions under the Federal Power Act. So far, district courts have decided that enforcement cases will proceed as traditional civil actions under the Federal Rules of Civil Procedure. If this interpretation of the FPA ends up being correct, FERC should reexamine its process in enforcement cases. The agency needs to carefully balance the procedural protections at the agency with the need to expeditiously resolve enforcement matters. If federal court review is likely to be more searching, the agency may need to streamline consideration of the actions at FERC. The court decisions provide the agency an opportunity to take a fresh look at those processes.

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

ONE HUNDRED FIFTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE

2125 RAYBURN HOUSE OFFICE BUILDING
WASHINGTON, DC 20515–6115

Majority (202) 225-2927
Minority (202) 225-3641

December 19, 2017

Ms. Noha Sidhom
CEO
TPC Energy
600 Pennsylvania Avenue, S.E.; Suite 300
Washington, DC 20003

Dear Ms. Sidhom:

Thank you for appearing before the Subcommittee on Energy on November 29, 2017, to testify at the hearing entitled "Powering America: Examining the Role of Financial Trading in the Electricity Markets."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

House Committee on Energy and Commerce

Subcommittee on Energy

Powering America: Examining the Role of Financial Trading in the Electricity Markets

Noha Sidhom, CEO, TPC Energy, on behalf of the Power Trading Institute ("PTI")

Responses for the Record

1. *Financial trading institutions, such as yours, execute financial trades with the purpose of making a profit. When your company makes money from a financial transaction, such as an FTR, where does your payout come from? Do consumers pay for your payout through their electricity bills?*

Consumers do not pay for the payout received by a Financial Transmission Right ("FTR") owner, if that position is in fact profitable. FTR contracts are settled at the wholesale level and not at the retail (consumer) level. That is, sales of FTRs in the auctions conducted by the Regional Transmission Organizations/Independent System Operators ("RTOs/ISOs") are paid by the purchasing entities, which include, but are not limited to, generation owners, trading institutions, load serving entities, and private investors, and paid to load serving entities who were allocated transmission rights on behalf of the consumers they serve. Then, each day, owners of FTRs receive or pay the value of congestion determined in the day-ahead wholesale electricity markets conducted by the RTOs/ISOs.

To understand fully the flow of money with respect to FTRs, it is important to understand that load serving entities are the wholesale market participants who supply power to consumers. What consumers pay for power supply is based upon the terms of the contract between each consumer and its respective load serving entity. This type of arrangement allows for consumers to choose to be protected from the volatility and complexity of wholesale electricity markets, since the load serving entities are the ones who are participating in the wholesale markets, including FTR markets. This type of arrangement also allows for consumers to understand how their electricity bills will be determined on a forward basis; in other words, it creates certainty for consumers. The responsibility of participation, including financial settlement and risk management, in the wholesale markets falls squarely on the load serving entity, and unless otherwise agreed upon through the contractual arrangement between load serving entities and consumers, consumers are not exposed to commercial activity in the wholesale markets.

The importance of wholesale competitive markets to consumers cannot be overstated. The billions of dollars in savings that consumers realize as a result of competitive markets can be attributed to, for example, allowing wholesale power generation service providers to compete with each other to sell electricity to consumers who will buy it at the lowest possible price. These cost-saving benefits to consumers have been quantified in a number of studies. In a recent report released by the COMPETE Coalition, from 1997 through 2014, prices in consumer-choice jurisdictions increased 4.5% *less* than inflation, while prices in regulated jurisdictions rose 8.4% *more* than inflation.[1] These results demonstrate significant savings to consumers.

2. *What potential market or regulatory reforms should Congress or FERC be considering in order to increase the market benefits associated with financial trading?*

PTI makes the following recommendations to both Congress and the Federal Energy Regulatory Commission ("FERC" or "Commission"):

a. FERC should mandate immediate compliance with Order No. 681 and ensure that all RTOs/ISOs implement long-term auctions. Long-term auctions provide a necessary forward price curve to ensure that the system

[1] O'Connor, P. and O'Connell-Diaz, E., *Evolution of the Revolution: The Sustained Success of Retail Electricity Competition* at 5-7 *available at* https://sites.hks.harvard.edu/hepg/Papers/2015/Massey_Evolution%20of%20Revolution.pdf.

is not overbuilt and consumers are not paying for unnecessary facilities for years to come.

b. FERC should ensure that congestion costs incurred by the market are borne by those who cause those costs to be incurred. As discussed in PTI's testimony, New York ISO currently allocates congestion costs to transmission owners. As a result, New York ISO, unlike every other ISO, has very few late scheduled outages or forced outages. New York ISO's paradigm provides the appropriate economic incentive for transmission owners to manage their outage schedules. Juxtapose this to the California ISO, which noted in a recent report that for outages subject to a 30-day advance notice requirement under the tariff, about 57% of these outages were not submitted to the ISO on time. Specifically, the report noted that in PG&E, SCE, and SDGE outages subject to the requirement were not received in time 50%, 65%, and 70% of the time, respectively.[2]
c. Congress should ensure that the RTOs/ISOs have the most up-to-date technology possible to solve their models.

3. *In your testimony, you stated that FTR revenue inadequacy is caused by a market design flaw that needs to be resolved. While PJM's Market Monitor has also stated that the current market design needs to be reformed, he believes any changes should ensure that load receives all congestion revenues. How do you respond?*

In a FERC decision on Rehearing dated January 31, 2017, the Commission explicitly rejected Dr. Joe Bowring's[3] argument that the purpose of FTRs is to return congestion revenues back to load. The Commission clearly affirmed its decision on Rehearing and stated as follows:

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[3] Bowring is President of Monitoring Analytics, PJM's market monitor.

> We reject the arguments that the sole purpose of FTRs is to return congestion revenue to load and the market should therefore be redesigned to accomplish that directive. FTRs were designed to serve as the financial equivalent of firm transmission service and play a key role in ensuring open access to firm transmission service by providing a congestion hedging function. The purpose of FTRs to serve as a congestion hedge has been well established. In the Energy Policy Act of 2005, Congress added section 217(b)(4) to the FPA,[4] directing the Commission to exercise its authority to "enable load serving entities to secure firm transmission rights (or equivalent tradable or financial rights) on a long-term basis for long-term power supply arrangements made, or planned, to meet such needs." In Order No. 681, the Commission clearly emphasized the significance of FTRs in hedging congestion price risk.[5]

Further, FTRs are inextricably linked to the underlying delivery of power to customers, and they are integral to shielding consumers from the price volatility that comes with having to perfectly balance the grid every minute of the day. The ability for load serving entities to shift their risk away from their customers and onto a counterparty that is better able to manage that risk is critical for protecting consumers. Without a proper forward price curve that is developed by forward congestion values from FTR auctions, suppliers, load serving entities, financial participants, and financial institutions would have to build in substantial risk premiums in order to be able to take on such significant risk without any type of hedging opportunity. This would effectively be a dead weight tax on consumers. Therefore, without FTRs, electricity prices would undoubtedly increase for ratepayers.

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[4] 16 U.S.C. § 824q(b)(2)(2012)

[5] *See* PJM Interconnection, L.L.C., Order on Rehearing and Compliance, 158 F.E.R.C. ¶ 61,093 (2017) (*quoting Long-term Firm Transmission Rights in Organized Elec. Mkts.*, Order No. 681, FERC Stats. & Regs. ¶ 31,226 at P 169, *reh'g denied*, Order No. 681-A, 117 FERC ¶ 61,201 (2006), *order on reh'g and clarification*, Order No. 681-B, 126 FERC ¶ 61,254 (2009)) .

Monitoring Analytics and Dr. Eric Hildebrandt[6] both argue that FTRs could be traded on a separate exchange, failing to recognize that FTRs are fundamentally linked to the day-to-day operations of the grid. The pricing of these rights is utilized in the transmission planning process; the number of rights allocated shifts based on the physical capability of the grid in a manner only the RTO/ISO can model and alter. And only the RTO/ISO can reconfigure the actual right, meaning they can change the path from A to B to A to C, if that is the more appropriate configuration that needs to be priced and allocated. In fact, FERC recently opined on the reconfiguration and reallocation of rights in PJM. Historical rights that were not reflective of the current transmission system were being allocated, causing distortions in the modeling and pricing. FERC mandated that PJM update its allocation process to allocate rights based on the current system.[7] Only the RTOs/ISOs can model the physical system constraints that will be applicable for the period auctioned in order to determine an appropriate price based upon the preferences of willing buyers and sellers.

In addition, FTRs are paid from day-ahead revenue that is not just an exchange of money between FTR traders, but rather a blend of complex activity by all market participants, including generation owners and load serving entities. An exchange would not incorporate this activity. Lastly, the RTOs/ISOs are the only entities that can adequately model and address planned outages in their auctions. For example, if line A holding 200 MW of capacity is scheduled to be out for maintenance for two weeks next month, the ISO is the only one that can prorate the capacity auctioned off next month to 100 MWs, instead of the 200 MW that line would ordinarily provide if it was in service all month. This is precisely why the California ISO report noted above discussed the importance of timely outage scheduling.

As a result, taking these products to an exchange separates rational congestion management activity from the economic activity to balance supply and demand on the

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[6] Hildebrandt serves as market monitor for the California ISO.

[7] PJM Interconnection, L.L.C., Order on Rehearing and Compliance, 158 F.E.R.C. ¶ 61,093 (2017).

transmission grid and would ultimately increase costs for consumers. From a legal perspective, such a divided structure would go against the core principles of Order No. 888,[8] the key FERC order instituting open access. Last and most important, the Commission was clear that a full redesign of the FTR market is not warranted.[9]

In a commodity market, such as electricity, there are natural buyers and natural sellers. Financial participants provide a counterparty to those entities and create a liquid market for those transactions to occur. As discussed during PTI's testimony, an FTR is a fixed for floating swap; meaning Participant A is getting paid to take on the risk, while Participant B has chosen to shift that risk to Participant A in exchange for a fixed price. Participant A may make or lose money, but Participant B no longer carries that risk. Therefore, financial participants shift risk away from load serving entities, which have contractual arrangements with consumers, by being a counterparty in these markets.

As stated in PTI's statement for the record, the forward price signal that FTRs provide to the market leads to more efficient infrastructure development. The organized markets have to balance the need for additional infrastructure development with the cost of congestion. Does it make sense to build a new transmission line or a new plant in a particular region or pay for the cost of congestion in that region, if that would overbuild the system to the detriment of consumers? The only way to answer that question is to have a forward price curve where willing buyers and sellers take on economic risk and provide a forward price signal to evaluate the need for such infrastructure. It is important to note that the organized markets have not seen load growth over the past several

[8] Promoting Wholesale Competition Through Open Access Non-discriminatory Transmission Services by Public Utilities and Recovery of Stranded Costs by Public Utilities and Transmitting Utilities, Order No. 888, 61 Fed. Reg. 21,540 (May 10, 1996), FERC Stats. & Regs. ¶ 31,036 (1996).

[9] *See* PJM Interconnection, L.L.C., Order on Rehearing and Compliance, 158 F.E.R.C. ¶ 61,093 (2017) ("[T]he Market Monitor and Joint State Commissions reiterate the proposal . . . that the Commission should support a market redesign to ensure loads receive all congestion revenues. We reject the arguments that the sole purpose of FTRs is to return congestion revenue to load and the market should therefore be redesigned to accomplish that directive.").

years.[10] Overbuilding the system would thus be an unnecessary cost that consumers would bear for decades to come.

When thinking about how the money flows, it is important to remember that a small portion of these rights are actually auctioned off and a large majority is allocated to utilities that serve retail customers. In fact, only the excess capacity is auctioned off in the FTR auction. These rights in total reflect the expected physical capability of the transmission system to deliver electricity; they are finite and their number is determined through analyses conducted by the organized markets. These finite rights are allocated to the transmission customers, also known as load serving entities, representing consumers that have paid for the fixed investment in the transmission system and are thus entitled to rights to the electricity transfer capability of this system. Transmission customers are allocated a certain number of contracts. How do we determine the value of these contracts that are provided to the transmission customer? The value of the allocated rights is determined in the open auction. Bilateral contracts are also priced off of the auction price. Basically, this is a public auction of excess capacity.

When there is no liquidity in the open auction or competition to arrive at an efficient price, the value of that contract diminishes because parties build in a risk premium. Simply put, without a locational FTR market construct, there is no mechanism to price bilateral contracts or allocated rights.

In short, FTR auctions save consumers money in four key ways:

- They provide an accurate price for the contracts that are allocated to transmission customers representing consumers.

[10] *See, e.g.*, PJM Interconnection, L.L.C., Where has Electricity Demand Growth Gone in PJM and What are the Implications? (2014), *available at* https://www.eia.gov/conference/2014/pdf/presentations/sotkiewicz.pdf; *see also* Analysis Group, Electricity Markets, Reliability and the Evolving U.S. Power System 27–28 (2017), *available at* http://www.analysisgroup.com/uploadedfiles/content/insights/publishing/ag_markets_reliability_final_june_2017.pdf.

- They provide a price for the congestion on the grid to determine whether or not the cost of congestion is a more appropriate investment than the build out of additional infrastructure.
- They provide a price signal to lenders financing infrastructure development which thus reduces the cost of financing.
- The trading of financial products results in a more competitive, liquid, and transparent wholesale electricity market which ultimately leads to reduced costs for consumers.[11]

4. *In your written testimony, you stated that the hardware and software used by the RTOs is inadequate and outdated – you provided an example where PJM was a week late in solving its FTR auction. Is the solution simply for the RTOs and ISOs to focus time and money on this issue, or is something else holding them back?*

PTI does not believe that the RTOs/ISOs have adequately focused on technology. More importantly, there is a lack of transparency regarding hardware and software upgrades. It would be extremely beneficial for FERC to require each RTO/ISO to file an annual report stating which upgrades or improvements have been accomplished and which upgrades or improvements are planned for the coming year. Critical information regarding model solve time improvements as well as auction time improvements should be a strong focus of the reporting requirement. The answer should not be to limit market activity, and it is critical for both Congress and FERC to not allow the RTOs/ISOs to limit competition under the guise of technological limitations. In other words, financial products should not be limited in either implementation of necessary products or in volume of current products because the RTOs/ISOs have not adequately maintained their systems to meet market participant demands.

[11] S*ee, e.g.*, Thomas, et al., *Electricity Customer Choice in Ohio: How Competition Has Outperformed Traditional Monopoly Regulation*, Cleveland State University (2016), *available at* http://engagedscholarship.csuohio.edu/cgi/viewcontent.cgi?article=2420&context=urban_facpub; Compete Coalition, RTO and ISO Markets are Essential to Meeting our Nation's Economic, Energy and Environmental Challenges (2014).

5. *In your testimony, you recommend that FERC's enforcement office should make publicly available the screens they use to identify targets for investigation. However, if FERC reveals its methods to flag misbehavior would this not give bad actors a roadmap to avoid FERC's policing of suspicious trading activity?*

PTI does not believe that FERC providing its enforcement screens to the industry would provide bad actors with a roadmap to skirt those screens. We believe this is akin to stating, inaccurately, that by sharing the law of the land you are providing a roadmap for citizens to break such laws. The very opposite is true. Providing the rules forces civil discourse regarding the rules, allows others in industry to police for behavior that the Commission considers manipulative or similar behavior and assists compliance officers in the industry to build better, more comprehensive enforcement programs.

The FTR forfeiture rule in PJM is a great example of this issue. The FTR forfeiture rule is a rule that states that a market participant would have to forfeit profit from a long-term position, if that market participant's short-term position impacted the pricing of the long-term position. For many years there was a lack of transparency regarding application of the rule and the Market Monitor in PJM made this very same argument that providing clarity regarding the rule would help market participants avoid direct violation of the rule. The Commission opened this issue up for debate and PJM stated that the current administration of the rule was punitive and proposed changes in accordance with discussions in the stakeholder process. Clear rules for market participants and an open dialogue regarding such rules assists both market participants in developing more sophisticated compliance programs and FERC enforcement in building a better, more constructive enforcement regime.

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

ONE HUNDRED FIFTEENTH CONGRESS

Congress of the United States

House of Representatives

COMMITTEE ON ENERGY AND COMMERCE
2125 RAYBURN HOUSE OFFICE BUILDING
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Minority (202) 225–3641

December 19, 2017

Mr. Vince Duane
Senior Vice President, Law Compliance and External Relations
PJM Interconnection
2750 Monroe Boulevard
Audubon, PA 19403

Dear Mr. Duane:

Thank you for appearing before the Subcommittee on Energy on November 29, 2017, to testify at the hearing entitled "Powering America: Examining the Role of Financial Trading in the Electricity Markets."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

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Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

Vincent Duane
Sr. Vice President, Gen. Co., Compliance & Ext. Relations

PJM Interconnection, L.L.C.
2750 Monroe Blvd.
Audubon, PA 19403
[redacted]

January 9, 2018

The Honorable Fred Upton, Chairman
Committee on Energy and Commerce
Subcommittee on Energy
2125 Rayburn House Office Building
Washington, DC 20515-6115

Re: November 29, 2017 Hearing – Response to Additional Questions for the Record

Dear Chairman Upton,

Thank you for the opportunity to testify before the Subcommittee on Energy of the Committee on Energy and Commerce of the U.S. House of Representatives on November 29, 2017 at the hearing entitled "Powering America: Examining the Role of Financial Trading in the Electricity Markets," and for the opportunity to address additional questions of subcommittee members.

Attached are my responses to those additional questions per your letter dated December 19, 2017. Thank you and the Subcommittee for your continued time, effort and consideration of perspectives offered. Should you have any questions with regard to the attached, please do not hesitate to contact me.

Sincerely,

[redacted]

Vincent Duane

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy
Ms. Allie Bury, Legislative Clerk, Committee on Energy and Commerce

Attachment: Responses of Vince Duane, Additional Questions for the Record

<u>The Honorable Fred Upton</u>

1. **You stated that financial trading in the electricity markets can be "too much of a good thing", and that in some circumstances, needs to be prevented if the trading does not deliver any efficiencies to the electricity markets.**

    a. **However, a broader question is whether RTO markets should host this type of trading activity at all? Isn't financial trading more appropriate on a financial exchange like NYMEX or the Intercontinental Exchange (ICE) rather than in a physical RTO/ISO market?**

<u>Answer</u>

RTO markets should host financial trading only to the extent financial trading improves the performance of the predominantly physical RTO/ISO markets. RTO/ISOs should not, and PJM does not, create financial instruments to attract financial trading as an end unto itself or to compete with secondary market exchanges or platforms that can and do offer swaps, options and futures contracts used to hedge or speculate on PJM forward prices.

PJM offers two products that have clear financial characteristics – virtual bids/offers and financial transmission rights (FTRs). But even these products have unique design elements which support and tie them very closely to PJM's physical market operations; to wit PJM's commitment, dispatch and delivery of electricity to supply load.

A virtual trade is a forward contract, committing the counterparty to either buy or sell electricity the following day at a price to be determined in that day's spot market. The obligation associated with a virtual trade (to buy or sell the next day) can be settled financially, which is to say, the counterparty need not deliver, or take delivery of, physical electricity. An FTR has different tenures (monthly, multi-month and annual). PJM's FTR regime (which includes auction revenue rights (ARRs)) offers FTR and ARR holders superior efficiency and optionality to manage the risk of locational price differences in electricity as compared to physically firm transmission service, which can be curtailed or subject to redispatch.

As hopefully is evident from the foregoing product descriptions, both virtual trades and FTRs are integral to PJM's fundamentally physical operations. This fact was recognized by the Commodity Futures Trading Commission (CFTC) in 2013 when it granted exemptions to virtual and FTR transactions from potential Commodities Exchange Act jurisdiction. With reference to virtual trades, the final order granting these exemptions states:

> Although there is an apparent financial settlement nature of virtual and convergence bids and offers ... they are inextricably linked to the physical delivery of electric energy due to their being subject to the same aggregate physical capabilities of the electric energy transmission grid as other physical Energy Transactions.[1]

The CFTC proceeding that culminated in the Final Order cited above, is replete with evidence showing the association between RTO/ISO financial products and RTO/ISO operations, the volumetric limit to these products constrained by the physical character of each RTO/ISO system and the efficiency and convergence role these products can provide to RTO/ISO market operations. The role that the RTO/ISO physical system plays to define and constrain the financially settled transactions that occur in these markets distinguishes those transactions from those occurring in distinct CFTC-regulated secondary market environments.[2]

Finally, I would note that ISO/RTOs, pursuant in part to FERC Order No. 741,[3] have adopted practices and protections developed in CFTC-regulated markets to manage credit, default and potential gaming concerns unique to financial trading. So, while I do not believe the types of virtual and FTR transactions offered by PJM could be replicated by CFTC-regulated exchanges or swap dealers and brokers, the sophisticated protections developed in these environments have been adopted and applied with good result in PJM.

[1] Final Order in Response to a Petition From Certain Independent System Operators and Regional Transmission Organizations to Exempt Specified Transactions Authorized by a Tariff or Protocol Approved by the Federal Energy Regulatory Commission or the Public Utility Commission of Texas From Certain Provisions of the Commodity Exchange Act Pursuant to the Authority Provided in Section 4(c)(6) of the Act, RIN 3038-AE02, p.32.

[2] While appropriate to examine fundamental premises as part of the hearing record, it should be noted that Congress itself acknowledged in Section 1233 of the Energy Policy Act of 2005 (the "native load" provisions of "EPACT 2005"), the link among financial transmission rights, service to native load customers and the RTO/ISO's planning obligations which work to ensure the value of those rights on a long term basis.

[3] Credit Reforms in Organized Wholesale Electric Markets, Order No. 741, 133 FERC ¶61,060 (2010).

2. **PJM's Independent Market Monitor has taken the position that the current FTR market design is flawed and does not ensure that load serving entities receive all the congestion revenues. Does PJM share the position of its independent market monitor?**

Answer

PJM does not agree that its current FTR market design is flawed. We do, however, agree that the FTR market is not designed to ensure that load serving entities receive all congestion revenues. The market is designed to afford load serving entities entitled to an allocation of FTRs (or to be more technical, an allocation of auction revenue rights) the opportunity to hedge congestion risk associated with deliveries from generation to load.

The allocation of financial rights (FTR/ARRs) serves as the paradigm in organized wholesale electricity markets by which the ISO/RTO, as transmission provider, meets its obligations to provide to customers open access firm transmission service. In non-market regions of this country, transmission customers take physically firm service. Importantly, physically firm transmission service does not mean a transaction cannot be curtailed, subject to TLRs, or redispatch costs. In theory, transmission service providers (both those providing financial rights and those providing physical rights) can reduce or eliminate altogether instances where either the financial rights allocation fails to hedge all congestion exposure or where physical rights have to be curtailed, respectively. This outcome can be achieved by applying very conservative estimates of the available capacity on the transmission system in deciding on the number of FTR/ARRs to offer or the number of physical transmission service requests to approve, respectively.

While such conservatism can assure that an FTR fully offsets congestion cost or that a physical transaction is never curtailed, this overly-cautious approach would effectively discount the real transfer capability of the respective system under normal and reasonably foreseeable system conditions. In effect, this overly cautious approach underutilizes the system and will result in a suboptimal level of transmission transactions relative to the capability of the system.

As is equally true for traditional physical transmission service providers, the only way to offer a customer an absolute guarantee of firm service would be to grant an unreasonably low level of transmission service requests. Consequently, when Congress addressed financial transmission rights in EPACT 2005, it made clear that transmission customers under an FTR/ARR regime are entitled to financial transmission rights to meet their "reasonable" load serving needs.

Finally, in PJM the highest priority of financial rights is allocated to load serving entities on paths aligned with physical energy deliveries. After first allocating financial rights requested by load serving entities, excess capability may be purchased by non-load serving entities. Excess capability is historically available only on those paths not aligned with congestion patterns. Therefore, typically where a non-load serving entity acquires rights on a path associated with physical energy delivery, it will pay a premium for these rights. This premium benefits the market by increasing revenues to all ARR holders, including load serving entities

The Honorable John Shimkus

1. **In answering my question regarding the degradation of firm transmission rights when the transfer from physical rights to FTRs occurred more than a decade ago, you stated that some entities ultimately were not hedged as they might have been otherwise. The Federal Power Act requires the FERC assure that RTOs reasonably plan and expand your transmission system to meet the foreseeable needs of Load Serving Entities. That planning includes the allocation of physical transmission rights (or at least equivalent financial rights) on a long term basis for LSEs that have long term power supply arrangements. Isn't it reasonable that entities that had long term firm transmission rights be held harmless by your tariffs? At a minimum, shouldn't your system provide them equivalent or comparable access to their resources without excessive congestion cost if they originally had a long term firm transmission path? If not, how is your market design just and reasonable if it causes costs or price escalation for resources owned by entities that held long term firm transmission rights?**

Answer

Long term firm transmission customers in PJM are allocated ARRs recognizing these customers paid originally for transmission for their load to access resources. When PJM's energy market prices separate, which is to say prices at the where power is injected differ from the where power is withdrawn, the transmission customer is exposed to congestion – a higher locational price at the delivery point as compared to the price realized by the generator at the point of injection. A transmission customer can hedge this price differential by holding an FTR on the pathway between these locations. The FTR is funded by congestion revenues collected by PJM.

A transmission customer is first allocated a level of ARRs in an amount commensurate to its transmission service, and subject to PJM's transfer capability modeling described in my response to the second question above. A customer can elect to convert its ARRs into FTRs and can (subject to caveat mentioned in the response above) thus deliver energy effectively congestion free from its historic resources to its load. Additionally, however, PJM's financial rights regime works such that if the transmission customer elects not to convert its ARRs into FTRS, it will instead receive the revenues realized by selling these FTRs in PJM administered auctions. Giving a transmission customer this optionality permits them to monetize FTRs they would otherwise hold if the customer believes other market participants in PJM place a greater value, and thus will pay more, than what the transmission customer believes the FTR is worth. Customers that take this route may realize revenues in excess of the congestion costs they end up being exposed to. But the other side of the bet also exists. By assuming the floating price risk of congestion in return for fixed revenues coming out of the FTR auction, the customer may not be fully hedged to actual congestion costs as they occur. Depending on system conditions and resulting levels of congestion, the customer thus may end up paying more in congestion than it received by way of auction revenue rights. This outcome, of course, is the result of the customer's financial decision, and is not a pre-ordained consequence of PJM's market design.

Your question references the obligations imposed by the Federal Power Act to plan and enhance the transmission system in order to meet a long-term, firm customer's reasonable needs. The scope and interpretation of this standard has been subject to debate before FERC. A particular question as to how the law defines a customer's "reasonable needs" was addressed by the FERC in Order No. 681.[4] In this Order, FERC provided a guideline which stated that "transmission organization may propose reasonable limits on the amount of existing capacity used to support long-term firm transmission rights such as minimum daily peak load or 50 percent of maximum daily peak load." In PJM compliance filings made pursuant to the final rule, certain parties protested that "reasonable needs" for purposes of FTRs should mean whatever a customer may need at any point in time to deliver energy to load. PJM instead proposed a standard it describes as the customer's "zonal base load," which conforms to the minimum daily peak load guidance offered by the FERC in Order No. 681. PJM's standard was ultimately accepted by FERC over objection by certain customers with the Commission reasoning that PJM's proposal met the requirements of both Order No. 681 and the Federal Power Act's "reasonable needs" standard.

Importantly, once this standard is triggered, PJM is required by law to expand its transmission system, as correctly noted in your question. Recently, in order to ensure that a legally sufficient allocation of ARRs could be maintained to transmission customers in Illinois, PJM ordered development and construction of a 345kV transmission project, known as the Grand Prairie Gateway Project, to enhance congestion free transfer capabilities in the Commonwealth Edison zone, for the benefit of long term transmission customers in that zone. This project offers an excellent illustration of how Congress' EPACT 2005 amendments to the Federal

[4] See *Long-Term Firm Transmission Rights in Organized Electricity Markets*, Order No. 681, 116 FERC ¶ 61,077 (2006).

Power Act work to provide long term transmission customers in PJM an appropriate degree of congestion hedge while not subjecting all customers to inefficient and expensive overbuilding of the transmission network. The "reasonable needs" standard adopted by EPACT 2005 appropriately balances the needs of an individual customer while ensuring just and reasonable rates for the broader set of transmission customers.

GREG WALDEN, OREGON
CHAIRMAN

FRANK PALLONE, JR., NEW JERSEY
RANKING MEMBER

ONE HUNDRED FIFTEENTH CONGRESS

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December 19, 2017

Mr. Chris Moser
Senior Vice President of Operations
NRG Energy
804 Carnegie Center
Princeton, NJ 08540

Dear Mr. Moser:

Thank you for appearing before the Subcommittee on Energy on November 29, 2017, to testify at the hearing entitled "Powering America: Examining the Role of Financial Trading in the Electricity Markets."

Pursuant to the Rules of the Committee on Energy and Commerce, the hearing record remains open for ten business days to permit Members to submit additional questions for the record, which are attached. The format of your responses to these questions should be as follows: (1) the name of the Member whose question you are addressing, (2) the complete text of the question you are addressing in bold, and (3) your answer to that question in plain text.

To facilitate the printing of the hearing record, please respond to these questions with a transmittal letter by the close of business on Tuesday, January 9, 2017. Your responses should be mailed to Allie Bury, Legislative Clerk, Committee on Energy and Commerce, 2125 Rayburn House Office Building, Washington, DC 20515 and e-mailed in Word format to Allie.Bury@mail.house.gov.

Thank you again for your time and effort preparing and delivering testimony before the Subcommittee.

Sincerely,

Fred Upton
Chairman
Subcommittee on Energy

cc: The Honorable Bobby L. Rush, Ranking Member, Subcommittee on Energy

Attachment

nrg

NRG Energy, Inc.
804 Carnegie Center
Princeton, NJ 08540

January 8, 2018

VIA OVERNIGHT & ELECTRONIC MAIL

Allie Bury
Legislative Clerk
Committee on Energy and Commerce
2125 Rayburn House Office Building
Washington, D.C. 20515

Dear Ms. Bury:

Attached please find responses to Chairman Upton's December 19, 2017 follow-up questions to my testimony before the Subcommittee on Energy hearing on November 29, 2017 entitled "Powering America: Examining the Role of Financial Trading in Electricity Markets."

Sincerely,

/s/ Christopher Moser
Christopher Moser

Enclosure

Attachment – Responses to Additional Questions for the Record

1. Can you explain how you use FTRs to keep prices low for NRG's consumers?

NRG utilizes Financial Transmission Rights, or FTRs, in three primary ways:

Retail Power Sales:

NRG purchases FTRs to hedge its retail sales of power. In the organized RTO/ISO electricity markets, there can be significant differences in the price we: (i) receive for sales from our power plants and (ii) pay to purchase power needed to serve our retail load obligations. These price differentials result from the fact that NRG's generation resources or power purchases are not always co-located with the customers we serve, which exposes NRG to the risk of congestion on the transmission system. Electricity costs more to make and deliver in crowded (or "congested") areas of the grid, such as large cities or areas that are far from generation.

NRG utilizes FTRs to manage this risk and provide predictable and stable prices to its end-use customers. Specifically, NRG can purchase an FTR along the path between a generating facility (or, more likely, a liquid point on the system, usually known as a "hub") and its end-use customers. For example, New York City's electric grid is as congested as its roadways. So if NRG sells electricity to a customer in the middle of New York City from a power plant located in upstate New York, it is likely that the transaction will incur additional congestion charges. Without FTRs, it would be difficult to predict exactly how much we would pay in extra congestion charges and we would have to include a larger "risk premium" in our prices to account for that uncertainty. A higher risk premium directly increases the price paid by end-use consumers. Purchasing an appropriate FTR, however, allows the parties to "lock in" those congestion charges, eliminating much of the congestion risk in exchange for an upfront payment.

Of course, purchasing FTRs costs money, which may reduce the profits we would otherwise earn. But the tradeoff is that we will not lose large amounts of money if unexpected congestion appears on the system. Overall, FTRs allow NRG to protect against unpredictable congestion on the transmission system, minimize the costs to retail customers, and increase our ability to offer customers long-term, fixed-price power deals.

Wholesale Power Sales:

FTRs are also critical to the process of selling our generation output to other retailers of electricity. For example, NRG often sells power from its power plants on a bilateral basis to other companies, who then re-sell the power to end-use consumers. The organized electricity markets facilitate these bilateral sales by providing both parties with open access to the transmission system and clear, transparent prices.

Whether the buyer or seller takes the risk of congestion is often a significant negotiating point. Sellers of power typically prefer that all risk of congestion (or even outright failure of the transmission system) transfer to the buyer at the point where the power plant injects the power into the grid. Buyers, on the other hand, typically prefer that the seller maintain the risk of successfully delivering the power. FTRs allow either party to manage the risk of transmission congestion by buying an FTR. If the sale of electricity is ultimately accompanied by any additional congestion costs, then the FTR makes the parties whole for those costs. Thus, FTRs provide an "insurance policy" against the risk that congestion will appear on the system and substantially alter the economics of the underlying transaction.

FTRs are particularly important when selling the output of large-scale renewable generators, which are often located far from load. In many cases, generators located far from load are subject to increased risk of congestion between the point of injection into the power grid and the point of delivery to an end-use customer. FTRs protect both sides of the transaction from congestion risk, which facilitates stable prices for both buyers and sellers of renewable power.

Transmission System Investments:

FTRs can be a powerful means of attracting additional at-risk capital into the transmission system, which is typically dominated by utility investment using captive ratepayer dollars. Most organized markets permit non-utilities to pay to upgrade an "element" of the transmission system that constricts the flow of power from Point A to Point B. In exchange for fronting the capital to make or advance the construction of the upgrade, the investor receives the value of any additional power flows across that element, usually in the form of FTRs or related products. Thus consumers receive new or accelerated improvements to the transmission system, while investors only make money to the extent the new/upgraded transmission improvement is actually used. This moves risk from captive customers to private investors, while increasing total infrastructure investment.

2. As a merchant utility with actual generating assets and retail customers, can you explain why and how NRG uses virtual transactions?

NRG likewise uses virtual transactions to manage sales from its power plants and to manage retail market positions. Virtual transactions are a powerful tool for managing the risk inherent in two-settlement electricity markets, where some power sales take place in the day-ahead market (the first settlement), and other sales take place in the real-time market (the second settlement). Prices can diverge between day-ahead and real-time markets as physical conditions on the grid evolve over time. These price differences are critical to the proper functioning of electricity markets, and are often caused by changing load forecasts (i.e., as we get closer to real-time, we better understand consumer demand, based on weather and other factors), changes in generator or transmission line outages, changing fuel costs, or other factors.

As a result, it is often more or less advantageous to sell (or purchase) power in either the day-ahead or real-time markets. Virtual transactions allow generators to pay a (usually small) fee to "virtually" shift their sales of power from the day-ahead to the real-time market, if conditions warrant.