Electricity Market Design

Financial Transmission Rights, Up To Congestion Transactions and Multi-Settlement Systems

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Introduction

The electricity market instrument designated as an "Up To Congestion" (UTC) transaction in markets like PJM is a financial instrument that is a variant of a financial transmission right (FTR). Financial transmission rights play a central role in efficient electricity market design. The purpose of this paper is to describe the nature and function of UTCs, the benefits associated with interactions with other elements of organized electricity markets, and an examination of the effect uplift cost allocation can have on efficient electricity design. The summary begins with the essential features of successful electricity market design. A key element of this design is the absence of physical transmission rights and the necessary reliance on the coordinated spot market. A feature of this design is the volatility and associated risks for spot-market electricity prices and the associated transmission usage charges. A long-term contract at a location provides a possible hedge, and the FTRs address the missing piece by providing forward hedges between locations. The UTC is part of this mix with distinct advantages that support efficient market operations. The interaction of FTRs, UTCs and other virtual transactions in a multi-settlement system is an important part of a consistent electricity market model. In principle and in practice these have different impacts on unit commitment and dispatch decisions, with implications both for the operation of the settlement systems and for allocation of system costs not included in the location marginal cost of energy. Settling financial contracts at the real-time electricity price provides the right incentives for efficient operation and better convergence between day-ahead and real-time. Allocating uplift costs to FTRs or virtual transactions, including UTCs, is not supported by principles of cost causation. The indicated policy would be to eliminate all residual cost uplift allocations to virtual transactions, and focus the necessary cost recovery by allocation to real-time load.

Electricity Market Design

The central idea of efficient electricity market design is to recognize the critical characteristics of the power system, to operate that power system efficiently, and to utilize prices and associated incentives that are consistent with efficient operation.

The most distinctive characteristics of the power system are the lack of adequate storage and the parallel flows of power on the grid. Due to the lack of adequate storage and the fast response of the system, system operators need to maintain essentially instantaneous balance of generation and load. This balance between generation and load occurs with power flows on the grid that move along every parallel path rather than through a system of valves and pipes. In effect, therefore, the configuration of load and dispatch of generation determines the use of the transmission grid. In every interconnected grid, a system operator is required to control the dispatch in order to control the flows on the grid within security limits.

This is not a new problem, and it is familiar to power engineers who have well-developed techniques and tools to coordinate system operations. In choosing the dispatch within the limits of power flow constraints, there is still a great deal flexibility. Some criterion needs to be applied, and the natural approach is to minimize the costs and maximize the benefits of the system. The term of art is to choose the "economic dispatch" to meet the load at the least cost subject to the security constraints.

Applying security-constrained economic dispatch is a well-developed practice in power systems. This traditional approach developed using engineering estimates of the operating costs of generation. The adaptation to markets was to replace the engineering cost estimates with the bids and offers of the market participants. With this change in the estimates, the form of the economic dispatch remained otherwise unchanged.

The second innovation of markets was to apply consistent prices to the purchases and sales determined in the economic dispatch. A by-product of determining the economic dispatch is calculation of the marginal costs of incremental power at each location. Following the usual definition of competitive markets, these marginal costs define the market-clearing prices associated with the economic dispatch. Under reasonable simplifying assumptions about the nature of the dispatch, taking these prices as given the generators and loads would have no incentive to deviate from the dispatch. These spot prices are known in the PJM system as Locational Marginal Prices (LMP). (Schweppe, Caramanis, Tabors, & Bohn, 1988)

Using any other materially different pricing system would by construction create a fundamental inconsistency with economic dispatch. This would require surrendering the benefits of efficient dispatch, restricting access or abandoning the principle of non-discrimination, or all of the above. There is no other principled pricing system that is compatible with economic dispatch, open access and non-discrimination. Therefore, the centerpiece of successful market design is bid-based, security-constrained, economic dispatch with locational marginal prices.

Financial Transmission Rights

The use of economic dispatch addresses the strong interactions of power flows in an electrical network. For equilibrium to hold at the efficient economic dispatch, the difference in market-clearing locational spot prices must equal the opportunity cost of transmission. Therefore, the consistent spot price for transmission is this difference in locational prices. If it were not for the strong interactions in the network, it would have been possible to define a set of physical rights for transmission, and these physical rights could have been traded to produce an efficient use of the network. In equilibrium, the spot price of these tradable transmission rights would be equal to the spot price of transmission under economic dispatch.

The replacement for the unworkable physical transmission rights is the financial transmission right (FTR) to collect the difference in the locational prices. (Hogan, 1992) Spot electricity prices are volatile, and the transmission spot price is even more volatile. The FTR is the right to collect the difference in the locational prices. In effect, the FTR is the equivalent of a physical right sold at the spot price without the necessity of actually trading the physical right. This provides a hedge for physical transactions between locations. The physical transaction incurs a spot charge at the difference in the locational prices. The FTR pays the differences in the locational prices. If the physical and financial transactions are exactly matched, then the net payments cancel as though the schedule had used the physical transmission right. From the perspective of the physical schedule, the transaction connects the source to the destination at the cost of acquiring the FTR. Hence, the FTR provides a hedge for the difference in locational prices.

The revenue to fund payments under the FTRs arises from the short term transmission rents in the economic dispatch at spot prices. The total payments by load exceed the payments to generators, reflecting the differences in losses and congestion that make up the spot market surplus. If the allocation of FTRs is simultaneously feasible for the grid conditions used in the economic dispatch, then under certain regularity conditions, the net of the spot market payments in the physical market will support the payments for the FTRs. (Hogan, 2002)

Allocation of FTRs can occur in a variety of ways. For example, a rolling or periodic auction can provide a market for FTRs covering a given forward period extending to months or years. The auction design includes an estimate of the applicable grid conditions in order to apply the simultaneous feasibility condition that underpins revenue adequacy. Additions to the grid can accommodate expansions and changes in the configuration of FTRs that preserve simultaneous feasibility. The fidelity of the estimated grid conditions is important in guaranteeing revenue adequacy. Changes in the flow of power or the configuration of load and generation would not affect the revenue adequacy result. But unplanned changes in the transmission network could make the existing FTRs infeasible. To the extent that grid conditions change in unexpected ways, payments under the FTRs might not be fully funded by contemporaneous spot market revenues. (PJM, 2012a)

Practical implementation of FTR definitions typically apply only to the congestion component of LMPs. The spot price can be decomposed into the reference cost of energy, the marginal cost of congestion and the marginal cost of losses. The reference cost of energy is the same for all locations and nets out for the locational difference in LMPs, leaving the difference in marginal costs for congestion and losses. The difference in the marginal cost of losses is less volatile than the difference in the marginal cost of congestion. Further, to include losses in the FTR definition requires an external party to provide a hedge for the total losses associated with the putative power flows in the FTR allocation. This is not true for the congestion component. If losses were zero, only the congestion difference in locational prices would apply. Hence, many models and most discussion apply only to FTR definitions for the difference in the congestion costs, and the difference in the charges for marginal losses remains unhedged. (Hogan, 2002)

The definition of FTRs includes possible treatment as obligations or options. In the case of obligations the holder of the FTR receives payment when the difference in congestion costs is positive and makes a payment when the difference in negative. Under the FTR option, the case of negative difference in congestion costs does not require a payment. The mix of options and obligations affects the simultaneous feasibility of FTRs. But for the present discussion the differences are not important and the focus of discussion is on the treatment of FTR obligations.

The FTR provides a critical piece in the elements of a workable and efficient electricity market design under the principles of open access and non-discrimination. The core contribution is in providing a substitute for the unavailable physical transmission rights that tie together the sometimes large locational differences in market conditions and associated LMPs. The existence of FTRs creates the opportunity to replicate many other features of efficient markets with an array of forward contracts and hedging instruments.

Day-Ahead Markets and Multi-Settlement Systems

The description of economic dispatch and FTRs applies to the real-time market. For a variety of reasons, the design of electricity markets includes or soon gravitates to include formal integration of forward markets that allow for advance notice for commitments, schedules and hedges. For example, a day-ahead market allows for more flexibility in planning the commitment of units and dealing with the complex dynamics of generation ramping. The analysis could include a multi-settlement system with hour-ahead, day-ahead and longer forward markets. The details are slightly different in each case, due to differences in scheduling lead times and mechanisms, but the important elements can be addressed by extending the real-time market to include a day-ahead forward market.

In essence, the day-ahead market looks similar to the real-time market. Participants make demand bids and supply offers. The system operator integrates these offers and bids with a description of the expected network conditions and determines an economic unit commitment and dispatch with associated LMPs. The participants settle for purchases and sales in the day-ahead market at the day-ahead prices. Bilateral transmission schedules pay for the schedule at the difference in the day-ahead prices.

There are other relevant details about commitment costs and related limitations on generation. But for the present discussion an important feature of this day-ahead, market-clearing, economic dispatch is that the schedules are effectively all financial contracts. No power flows in the day-ahead market. In real-time, when actual power flows, there will be another economic dispatch based on other real-time offers and bids. Although the mechanics of accounting and settlements may be different in each case, the net result would be the same as if all the day-ahead schedules were liquidated at the real-time locational spot price, and all real-time physical transactions were settled at the respective locational spot prices. This formulation is sometimes referred to as a "gross pool." An alternative interpretation is that the differences between the day-ahead and real-time quantities for a participant at a locational are settled at the real-time price. This is sometimes referred to as a "net pool." Note that the settlement system characterization does not affect the dispatch or the ultimate net payments by the market participants. The economics and the aggregate financial outcome are unchanged.

This recognition that all cleared schedules in the day-ahead market are financial contracts that can be settled at real-time prices immediately opens the possibility for expanded participation. Given the uncertainty in real-time, the day-ahead contracts provide a hedge against the volatility of real-time prices. The ability to provide these hedges is not limited to those who own generation or serve load. To the extent that expected real-time prices differ from the day-ahead prices, there is an arbitrage opportunity. This arbitrage possibility creates an incentive for purely financial participants to make bids and offers for financial contracts in the day-ahead market that will be settled at real time prices. Allowing the entry of these "virtual" bids and offers, called incremental bids (INCs) and decremental offers (DECs) in PJM, promotes entry and the benefits of competition that come with increased liquidity. This virtual bidding promotes price discovery, allows market-based redistribution of risk, and offers an opportunity to price risk in the electricity market.

The existence of a multi-settlement system affects treatment of FTRs. Any economic dispatch organized by the system operator inherently involves using the transmission grid to support the associated power flows. Embedded in the associated dispatch is an assignment of the use of the grid, with charges for transmission equal to the difference in the associated LMPs. Hypothetically, if there were physical transmission rights, the holders of these rights would sell them to be reconfigured for the use of the grid under the economic dispatch. In the absence of physical transmission rights, the same treatment must apply to FTRs. Inherent in the day-ahead market, therefore, must be the settlement of the FTRs at the day-ahead price.

This means that the FTR in a multi-settlement system is a hedge against the prices in the first of the sequence of settlements. In the case of day-ahead, this means that FTRs hedge the volatility in day-ahead prices, not real-time prices. In order to provide a complete forward hedge of the locational differences in real-time congestion costs, a market participant would need to have FTRs and convert these FTRs into another financial contract day-ahead in order to settle in real time. For example, a holder of an FTR obligation could introduce a day-ahead bilateral schedule for an equivalent amount of transmission between source and destination. Treated as a virtual contract that would be settled at real time, the day-ahead schedule would hedge the locational difference of real-time LMPs.

This link between virtual schedules in day-ahead, FTRs and real-time prices is necessary and inherent in the design of electricity markets. The physical analogy would be to conduct a reconfiguration auction for physical transmission rights in the day-ahead. Market participants would sell the long-term transmission rights day-ahead and purchase short-term rights for use in real-time dispatch. In the absence of a workable system of physical transmission rights the combination of FTRs and day-ahead virtual transactions addresses the same problem. The FTR is the long-term right that is sold each day in the day-ahead market. The day-ahead virtual transaction is the short-term right that provides the equivalent hedge for the difference in real-time locational prices. The intimate connection between FTRs and virtual transactions is an essential part of efficient and workable electricity market design.

Up-To Congestion Transactions

The inherent connection between FTRs and virtual transaction is most pronounced in the UTC product found in PJM. A similar financial contract can be found in the organized Texas market in ERCOT. The UTC product has many characteristics similar to FTRs. The basic idea is to arrange a virtual schedule day-ahead between two locations with a bid for the maximum payment in the difference in the LMPs between source and destination. This is a generalization of the simple bilateral schedule. Clearing the pure virtual bilateral schedule would not depend on the price differential in the day-ahead market. By contrast, the UTC product allows a bid for the maximum price at which the transaction should clear. This bid allows the market participant to limit the cost that will be incurred to obtain the real-time hedge.

The bid on a UTC is directly analogous to the bids on FTRs in the forward auction for transmission rights. In the forward auction, bids to purchase FTRs are determined by the market participant, and the bid limits the amount the participant is willing to pay to hedge the difference in day-ahead congestion prices between the source and the destination. The UTC is for the real-time congestion and loss prices between a source and destination. The bid on the UTC product limits the amount the market participant would pay for the relevant hedge in the same way as the bid on the FTR.

In PJM this UTC product has two restrictions. First, at least one of the locations has to be external to PJM. For historical reasons, the UTC applies only to imports, exports and through transactions. Second, there is a limit of $±50/MWh on the bid price. The net effect is to provide some ability to limit the costs of obtaining hedge real-time differences in some locational prices.

Like an FTR, a UTC hedges the difference in locational prices. The FTR hedges the locational difference in day-ahead LMPs. The UTC hedges the locational difference in real-time LMPs. The FTR covers marginal congestion costs. The UTC, despite its name, covers both marginal congestion costs and marginal cost of losses. The FTR in principle can be between any two locations in PJM. But in PJM the UTC applies only to external transactions.

A simple bilateral schedule in the day-ahead market would also hedge real-time differences in LMPs for both losses and congestion. The advantage of the UTC is that it includes a bid that permits a limit on the price differential paid day-ahead to obtain the real-time protection. In effect, the bilateral schedule between two locations is equivalent to a UTC between those same locations with a bid price so high (infinite) that it always clears. It is not evident why the appropriate implicit bid on the bilateral is effectively infinite, but the restrictions limit a bid on a UTC as between zero and $±50.

This UTC formulation is sometimes known as a "spread bid." In effect, bilateral schedules between any locations coupled with bid prices in the day-ahead market would be the equivalent of UTCs extended to all PJM locations, but without the limitation of the bid cap. Extension of UTCs to encompass all locations, without a cap on the bid, would expand the range of hedging opportunities and increase competition in the day-ahead market. For example, the ability to take FTRs to hedge real-time spot prices would be materially facilitated by allowing a more flexible UTC product. This would improve the ability to arbitrage locational differences and support price convergence between day ahead and real time.

Dispatch Interactions

In principle, FTRs, UTCs and all types of virtual transactions could be constructed through private arrangements outside the organized market administered by the RTO. Any consenting parties could write a contract that settled against PJMs LMPs, whether for day-ahead or real-time markets. These derivative contracts would be subject to market oversight, but they would not enter into view for the system operator. These financial contracts would not need to be explicitly considered in the commitment and dispatch.

The difficulty with leaving derivative contracting to the private market arises again from the absence of physical transmission rights and the inability of the bilateral market to address the strong interactions in the flow of power on the grid. While it is true that anyone can write a contract that looks like an FTR, UTC or virtual bid, only the system operator can support a set of contracts that fully respect and utilize the limited capacity of the grid. The need for coordination through the system operator is most obvious in the case of FTRs, but the same principles apply to any financial products that depend on prices that reflect the actual flow of power on the grid. In economic terms, the transaction costs of organizing an efficient commitment, dispatch and hedging configuration are relatively small when conducted through the system operator, and much larger or even prohibitive when left to the bilateral market.

The advantages of including these financial transactions in forward auctions are clear. The transactions can reflect the real limits of the grid, with all strong and complex interactions. This expands the set of feasible transactions and should both increase efficiency and reduce risk. The flip side of this inclusion in coordinated auctions by the system operator is that the financial contract bids and offers can affect the commitment and dispatch choices of the system operator, at least to some degree.

The degree of interaction depends on how the virtual and other financial transactions are represented in the forward markets. For example, FTRs that are only for congestion cost create no direct impact on losses or forward energy contracts. The award of FTRs may have some indirect effects on the development and availability of long lead-time generation facilities and loads, but the impact on the day-ahead or real-time dispatch would be de minimis. Likewise, in the real-time dispatch, financial bids and contracts are no longer part of the solution and it is only real physical conditions that determine the final dispatch and prices. In the day-ahead, the issue is more complicated and the degree of interaction depends on how the system operator models UTCs, virtual bids and other financial contracts.

The possibility of interaction between financial contracts and the market dispatch raises the concern that the financial bids could be used to manipulate the market. (Haas, 2009) A difficulty arises in considering the proper test of manipulation. The appropriate counterfactual would be an equilibrium solution without the financial bids. Consider the simplifying assumption of complete information, with a common probability distribution characterizing the uncertainty of real-time prices, and risk neutral financial participants. Then the day-ahead financial participants would produce financial bids at the common expected real-time price. With no restrictions on entry, any financial bids that deviated from the common expected real-time price would either lose money or would not clear. Under this condition, the strictly financial bidders, who could not affect the real-time price, could not affect the day-ahead price. Hence, the ability to affect day-ahead prices must depend on some combination of restrictions on entry, external limits on participation by risk neutral financial traders, or a more complicated information setting.

From this perspective, limitations on virtual bids and financial transactions work in the wrong direction. Expanded liquidity and ease of entry would improve the operation of the market and create a closer approximation of the idealized competitive day-ahead market. Given the benefits of coordinated markets and expanded opportunities for hedging, limitations on financial bids should be avoided or at least face a strong burden of justification.

Settlements and Cost Allocation

The principles of cost causation focus on the efficiency of price signals. Prices should be set to reflect costs on the margin. If the costs are well behaved, the balance induced by the equation of price and marginal cost supports the efficient economic outcome. With the simplest representation of supply and demand, including increasing marginal costs and decreasing marginal benefits, the efficient solution establishes a welfare maximizing market equilibrium. This is what motivates economic dispatch as the core feature of the electricity market model. And this idealized model would not create residual costs, with or without virtual transactions.

Uplift for Residual Costs

In the presence of fixed costs, joint products, and other departures from the assumptions of the simple market structure, prices that equate marginal benefits may not cover the full costs of production. This raises the question of how to allocate costs using principles that go beyond the simplest application of the cost causation principle. In the electricity market, for example, the problem arises when there are startup costs, minimum run times and other constraints on generators which imply that the efficient, least-cost solution may not be compatible with any given set of prices for outputs of the facility. There will a requirement to allocate the costs that cannot be covered at the prices determined by the variable costs. In the case of PJM, an example is the Balancing Operating Reserve (BOR) charge that covers a variety of startup and related costs that might exceed the revenues obtained at spot prices for the output.

The BOR charge allocation question, like similar applications such as the Revenue Sufficiency Guarantee (RSG) in the Midwest System Operator, produces an often confusing and circular conversation. (Hogan, 2008) Although the BOR allocation assigns different costs to different actions, the lack of an explicit model implies that the method is more an administrative compromise than the product of a principled analysis. The difficulty is fundamental. The underlying assumptions behind the cost causation argument, with the link between marginal costs and prices, do not apply to all the costs. The existence of discontinuities in the generator costs structure—the generator is on or off; the startup cost is incurred or it is not incurred, without any intermediate possibility—means that some of the costs may not be connected to marginal changes in output. A marginal change in output may have little or no impact on costs, even though the total costs of starting and maintaining the active generator may be large. If prices equal to marginal costs do not cover the full costs, then the residual costs need to be covered by appeal to some other principle. (Gribik, Hogan, & Pope, 2007) Appeals to cost causation principles to allocate the residual costs are self-contradictory. The very definition of the residual costs is for that part of the total costs that is not amenable to attribution at the margin. By definition, there is no cost causation allocation available for the residual costs.

In the allocation of joint or residual fixed costs, without the connection to cost causation at the margin, there is an inherent arbitrariness to the allocation. If there were no consequences in terms of choices in the market, an administrative compromise would present no policy problem. With multipart tariffs, the costs may be included in separate charges that differ from the marginal cost of output. The basic principle would be to allocate the costs in a way that would have the least impact on the choices made in the market. For example, allocating the costs to network connection charges would be better than adding to a so-called "uplift" charge on load. If an uplift charge is necessary, it should be allocated to the least responsive loads. If a non-discriminatory uplift charge is required, it should be spread across the widest possible base of loads that cannot bypass or avoid the charge.

Efforts to avoid this logic for cost allocation, by finding the cost causation connection for the residual costs left over from cost causation allocations, can only mislead. This is especially true for charges like the BOR which are residuals given the spot prices of output. The magnitude of the BOR is not only a function of total cost; it is also a function of the spot pricing rule. By definition, small changes in output provide no guidance for the cost allocation, and examples of large changes in the market big enough to create a correspondingly large change in costs inherently require arbitrary decision about joint effects, not independent marginal decisions. In effect, the cost allocation problem for residual costs inherits the problems of lumpiness and jointness that give rise to the existence of residual costs in the first instance. It is easy to fall into the trap of seeking a cost causation allocation, but it is the wrong path to follow.

The problem is especially important in dealing with transactions like FTRs, virtual trades, and UTC transactions, that have the common characteristic that they are financial contracts that do not imply or produce physical delivery or load in the real-time electricity market. By design and construction, these financial contracts will be settled at prices determined in the spot market, but the observed quantity will always be zero in the real-time physical flows. The underlying economics of the financial contract are driven by the expected value of the real-time price that will apply to the financial settlement of the contract. By design, the deviation between day-ahead and real-time for the financial contract is the full quantity, and for a competitive bidder there is no connection between this deviation and the appropriate economic analysis of the bid. Hence, allocating costs to these virtual contracts based on deviations does not have a foundation in the economics of a competitive bid and creates perverse incentives to avoid virtual transactions. Any added charge to the virtual contract creates a wedge between the expected real-time price and the day-ahead price, reducing the incentive and the ability to promote convergence of the prices. Uplift allocation to any virtual contracts has material consequences that work at cross purposes to good electricity market design.

A purpose of these contracts is to hedge or arbitrage in the face of uncertainty about prices. With no uncertainty there would be no demand for these contracts. And without risk aversion that gives rise to hedging, there would be no need for these contracts. In the real world, with uncertainty and risk aversion, these financial contracts improve the operation of markets. However, the fundamentals dictate that the supply and demand for the financial contracts would be very sensitive to transactions costs, including any assignment of the residual uplift costs like the BOR charges.

Virtual Trading and Financial Contracts

To avoid complicated simulations or examples of calculation of BOR charges, it helps to step back and think about the market conditions that give rise to the residual costs in the first instance, and the role of financial contracts in these markets. For example, much of the intuition about cost causation comes from an implicit connection to simple real-time markets for electricity in the so called "day one" structure that includes a real time spot market with one-part offers and bids for supply and demand. The offers and bids describe textbook supply and demand curves, and economic dispatch produces an efficient equilibrium with market clearing prices. Under these simplifying assumptions, we don't have lumpy decisions, and the market clearing prices would cover the costs. There would be no residual costs to allocate. Financial contracts could be arranged ahead of time in the bilateral market, but the actual dispatch would depend only on the final offers and bids provided to the system operator. The spot deliveries would differ from the financial contracts, so there would be substantial deviations for these bilateral contracts. But the deviations would be accounted for through the bilateral transactions and not known to the electricity system operator. In this simplified world, there would be no BOR cost to allocate.

Setting aside the problem of the lead time for starting up, we could modify this simple market to include multipart offers and bids to reflect startup costs, minimum run times and the other complications of generation. Assume for the sake of discussion that bilateral financial contracts are not organized through the system operator, but are strictly in the financial market. With the introduction of multipart bids the lumpiness of the economic dispatch solution would create the problem of residual costs that might not be covered by spot prices. Hence, cost allocations like for the BOR charge would be necessary. It would appear that the BOR charges arose not because of deviation from day-ahead schedules, but because of the fixed costs, minimum run levels and other constraints of generation. Allocation of the costs to the generators who caused the costs would be circular, because it is the under-recovery by these same generators that we seek to recover. In this hypothetical case the financial contracts, which are still bilateral and would not even be known to the system operator, would not be the cause of the BOR charges, and deviations of the financial contracts would not be used for cost allocation.

The lead time associated with startup and related schedules drive these "day one" markets towards the "day two" structure that includes a day-ahead market operated by the electricity system operator. The day-ahead market and associated schedules facilitate operations by allowing market participants to exploit a wider range of commitment and dispatch decisions. The expanded opportunity set, coupled with the close connection to the physical characteristics of load and generation, presents the occasion to achieve lower total costs. In principle, this day-ahead market could operate without including purely financial contracts at all. The commitment and dispatch, reflecting the lumpiness of the decisions, would give rise to the residual cost allocation requirement such as for the BOR charges. There could still be bilateral financial contracts, but there would be no requirement that the system operator even know about these contracts, which could be settled separately against the published prices. From the perspective of the system operator, there would be no observed deviations for the contracts and no cost allocation to the bilateral contracts. The residual costs would exist, but would not be caused by the financial contracts.

Once we have the day-ahead market structure in place, it becomes clear that there would be substantial advantages to the market as a whole to include financial contracts under the purview of the organized electricity markets. This provides the advantages of additional entrants in the day-ahead market, better price convergence, increased liquidity for hedgers and a natural way to resolve long-term financial transmission rights that address the locational differences in prices. This integrated market would be impossible to fully replicate through a strictly bilateral financial market.

Viewed in this way, residual costs arise independently of the financial contracts. The assembly of FTRs, UTCs and virtual transactions included in economic commitment and dispatch bring an added benefit to the market interaction, improving efficiency and lowering overall costs. Movement of financial contracts into the organized market run by the system operator can affect operations in ways that are beneficial to the system. However, the movement of financial contracts from the bilateral market into the organized market also makes the deviations of the financial contracts from the real-time market visible. Thus follows the conundrum. The residual costs like BOR charges arise because of the lumpiness inherent in the multipart offers and bids for generation and load. There may be some interaction between the financial contracts and the commitment decisions, but these interactions are intended to reduce total costs, not add to the total costs. Furthermore, it is the total costs, commitment and real-time dispatch, that should be the focus of any cost analysis and not the organization of these costs in different accounts such as BOR.

The change in commitment decisions may have some impact on dispatch and prices, and these changes may increase (or decrease) the allocation of costs into the residual category.[1] (PJM, 2012b) But these BOR charges at their root are not caused by the deviation of the real-time schedule from the day-ahead contracts. In this important sense, financial contracts do not cause residual costs such as the BOR charges. In equilibrium, and on average, including financial contracts should improve the aggregate efficiency of the system.

Consequences of Uplift Allocations

These benefits of coordinating financial contracts would be threatened by any increase in transaction costs or allocation of residual costs to the financial contracts. In the first instance, the parties always have the option to move back into the bilateral market where the costs are higher but the deviations are not available as an indicator for residual cost allocations. Even worse, financial participants might withdraw from the market altogether and eliminate the efficiency gains of the more transparent and liquid market operated with explicit recognition of day-ahead conditions and transmission interactions.

This high level perspective provides a view that would be lost by trying to do *ceteris paribus* simulations of changes in financial offers and bids, to calculate the impact on BOR charges. This simulation approach would mislead. The better perspective is that the residual costs arise because of the lumpiness of the technology and the need for multipart bids for day-ahead and real-time dispatch. In the absence of financial transactions, there would still be BOR charges. The right perspective is that the financial transactions reduce overall costs and provide better incentives for efficient markets.

Allocation of residual costs to financial transactions cannot be supported by cost causation arguments. The incentive effects of such allocations are perverse, because even small increases in these transactions costs can have a material effect on the activity of financial participants. By contrast, real load, in real-time, has nowhere else to go. Financial participants have many more options. Once we move past the cost causation argument, allocation of costs to the financial contract segment with the most options, in order to lessen the residual cost allocation to real load segments which will not change behavior, works in the wrong direction and reduces the overall benefits of organized markets.

In the PJM system, there is a separation of the commitment and dispatch costs according to a rule that involves a judgment about the impacts of particular types of bids. (PJM, 2012c) The distinction is to allocate some costs to deviations from day-ahead schedules, with no separate treatment of financial transactions, and the remainder of the residual costs to load. The arguments above are particularly applicable to the case of UTCs. In the practical implementation of markets there are always approximations inherent in implementation of security constrained economic commitment and dispatch. In the case of PJM, these approximations mean that UTCs do not affect the commitment organized through the multipart bids handled by the system operator. (PJM, 2012d) Since they do not affect the day-ahead commitment, UTCs cannot affect the real-time dispatch and costs. Hence, no deviation charges are allocated to UTCs. Likewise, since FTRs are strictly financial contracts that are established before the day-ahead commitment and dispatch, the judgment is that there are no residual cost allocations to FTRs.

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[1] See Table 2 in (PJM, 2012b), where the "changes" in day-ahead cost are negative for the inclusion of UTC transactions and positive for inclusion of other virtual transactions (sign conventions explained through an inquiry to PJM).

The objection arises that the current BOR cost allocation scheme in PJM exempts UTCs but includes allocations to deviation in other virtual trades. (Monitoring Analytics, 2012) The essence of the argument appears to flow not from a concern based on first principles of efficiency or cost causation, but from the asymmetry of the treatment between other virtual transactions and UTCs. Since the UTC is equivalent to a pair of virtual transactions with a linking constraint, why should they be treated differently? Is the justification nothing more than the particular simplification chosen for the PJM commitment decision? If there is no cost causation argument and the allocation is intended as a compromise to achieve rough justice, does the cost allocation have any effect on the market?

From the argument above, it follows that virtual transactions should help improve the efficiency of the market. Requiring financial contracts to settle for the difference in the electricity price of the transaction between the forward market and real-time market sets up the right incentives to affect day-ahead prices by improving convergence with expected real-time prices. But allocation of residual costs to the financial transactions does not follow from a coherent application of the principles of cost causation. And any cost allocation to virtual transactions creates perverse incentives that have material consequences on the efficiency of the market. The critique is correct that there is an asymmetry between the treatment of some virtual transactions and UTCs. The solution, however, is not to adopt the flawed residual cost BOR allocation to virtual transactions and extend it to UTCs. The solution is to preserve the BOR exemption for UTCs and FTRS, and then extend the same status to all virtual transactions. The residual cost allocation would then apply to real load, liquidity and entry in financial day-ahead virtual transactions would be enhanced, and the efficiency of the overall system should be improved.

Conclusion

Locational electricity prices from economic dispatch derive from marginal conditions and most directly lend themselves to interpretations of cost causation. In a simple system with idealized generation and load conditions the prices determined by the marginal calculations would cover the costs of operations and no further cost allocation would be necessary. In the real systems like PJM, where fixed costs of startup, minimum run levels, and reliability commitments contribute to circumstances where locational prices of electricity are not always sufficient to support the full economic commitment and dispatch, a cost allocation problem arises. The residual costs, left after the application of cost-causation principles, should be allocated in a manner that best supports or least inhibits operation of an efficient market. Financial contracts for virtual transactions day-ahead, for financial transmission rights, and for up-to-congestion contracts in PJM do not in the first instance create residual costs such as defined in the PJM Balancing Operating Reserve charges. The current system of cost allocation does not have a basis in first principles, and creates significant perverse incentives to favor one form of limited virtual transactions over the more flexible use of all virtual transactions. The indicated policy would be to eliminate all BOR charges and related uplift allocations to virtual transactions, and focus the necessary cost recovery by allocation to real-time load.

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