Forward Markets for Transmission that Clear at LMP: A Hybrid Proposal

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Abstract
Progress on restructuring of the US power system has been slowed, in part, by the debate over market design and, more specifically, over the design of the congestion management system. This paper proposes a hybrid model that combines the most critical elements of the flow-based and locational marginal price approaches. Specifically, the accounting interface between the simplified network representation of the forward market of the flow-based approach and the more detailed network representation of locational pricing for real-time settlements are elements of the hybrid model. This solution minimizes the amount of real-time congestion cost that is not included in the final cost of the transaction.

The California and PJM markets are examples of each of the isolated approaches, respectively. This paper uses them to illustrate the flaws in each of these market structures and to identify how each market would improve if operated under the proposed hybrid model.

Introduction

The debate over restructuring of the United States electric power industry has gone on far longer than many of us who have been involved from the start would ever have guessed. Two opposing perspectives continue to collide in the development of virtually every electric market region in the US. The first supports the development of a robust commodity market with a real-time mechanism for balancing the system i.e., for keeping the lights on. The second supports the need to maintain central control in order to keep the lights on, with liquid, forward wholesale markets operating around the edges.

The difference between these positions has had a critical impact on the process of industry restructuring. In the first instance it is assumed that markets will find economically efficient solutions to generation, transmission, and consumption processes. In the second it is assumed that the laws of physics and mathematical modeling will define a better (in fact the best or optimal) solution to the same problem. The first approach or model has been identified with concepts of zonal transmission pricing or, more recently, real-flow or flow-based transmission pricing. The latter model has been associated with locationally-based marginal pricing (LMP).

The objective of this paper is to argue that these two positions, while having been argued as polar extremes, can, in fact, be combined to provide both a robust and liquid forward market as well as a secure power delivery system. Figure 1 presents a paradigm of the time line of functional requirements of both the financial market and the physical delivery system in the electricity supply industry. There are functional requirements along the time line – from years to cycles – for both the market and the physical functions of the electricity sector. In terms of the physical system, the delivery of electrical energy occurs in real time with an operator in control of the functions from at most a day ahead (scheduling) through cycle to cycle operational supervision. The other physical requirements – the planning and construction of new investment in both transmission and generation and the scheduling and operation of maintenance – occur well in advance.

1 The author gratefully acknowledges the assistance of Narasimha Rao, Judith Cardell and Renee Rushnawitz in the writing of this paper. All errors and omissions, as well as interpretations, are solely those of the author and do not represent the position of either Tabors Caramanis & Associates or of Massachusetts Institute of Technology.

2 The first category is associated with the interests of independent power producers and marketers (the non-incumbents in the industry). Richard Tabors of Tabors Caramanis & Associates and MIT is associated with these alternatives. The second category is associated with the interests of the operators of the power system and the remaining vertically integrated utilities (the incumbents in the industry). Professor William Hogan of LECG/Navigant and Harvard University is associated with the latter.
The financial market, at the same time, performs its most critical functions significantly in advance of delivery and then again after actual delivery through both the balancing market and settlement procedures. The principle function of this forward market is to provide a mechanism by which individual consumers or aggregators of consumers can purchase forward and thus acquire a price hedge for their future needs. In a complementary way the forward market provides the energy producer with the option of locking in a price and quantity for delivery for an extended period at a future time. Both instances offer protection against future price uncertainty and price volatility.\(^3\)

The paper looks at two examples – PJM and California – and identifies the characteristics of each that are both positive and negative in terms of the development of robust electricity markets. The structure of the California market is an imperfect example (and one presently being corrected) of a structure that has focused on the separation of the elements of the market – the power exchange and the system operator in an effort to force the development of an independent market. The Pennsylvania New Jersey Maryland (PJM) tight power pool has evolved into an independent market. The Pennsylvania New Jersey Maryland (PJM) tight power pool has evolved into an independent market. The structure of the California market is an imperfect example (and one presently being corrected) of a structure that has focused on the separation of the elements of the market – the power exchange and the system operator in an effort to force the development of an independent market. The Pennsylvania New Jersey Maryland (PJM) tight power pool has evolved into an Independent System Operator (ISO) structure that focuses only on the development and reporting of the spot price.

The California market structure, Example 1

California began the process of restructuring its electricity markets with the publication of the “Blue Book” in 1994.\(^4\) The proposed restructuring was partially in response to similar actions being taken globally, but more in response to the economic conditions in California where consumers were facing some of the highest electricity costs in the country. The result of the process was dramatic and included legislation (California AB 1890, filed September 24, 1996) which called for the opening of all retail customers to competitive supply as well as a date certain by which all stranded asset costs were recovered or lost, 2002. After that date, and with the sale of some or all of the former vertically integrated utility’s generation assets, these companies could compete freely in the competitive market.\(^5\)

To operate the California competitive market, AB 1890 called for the establishment of a single system operator (the California Independent System Operator) that was to combine the grid operations of the three formerly independent utilities. New headquarters, staffing and hardware and software systems were created at the control center in Folsom, CA.

The legislature also created the California Power Exchange (CalPX) that was to be the entity responsible for coordinating the bidding and balancing of the generating resources and the demand from the previously vertically integrated utilities. Because the former vertically integrated utilities were required to participate in the market only through the CalPX, it quickly became the dominant player for scheduling even though others were allowed to be independent Scheduling Coordinators.

In an effort to simplify the market process, the structure that was established essentially divided the state into two zones for the purpose of transmission operations and congestion management.\(^6\) The dividing line was a well-known transmission constraint in the lower portion of the PG&E territory known as “Path 15.” This simplified definition allowed for the market to adjust to congestion across Path 15 and required a complex set of rules for dealing with the congestion that might arise within the zones themselves.

The market quickly began to hit bumps. Both the separation of the market maker elements from the market

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\(^3\) One need only look at the example of the volatility in the electricity spot market in California in the summer of 2000 or the volatility in the Midwest markets in the summer of 1998 or 1999 to recognize the importance of assuring price volatility hedges for consumers in the market.


\(^5\) Note that the legislature included only the investor owned utilities in its mandate, San Diego Gas and Electric, Pacific Gas & Electric and Southern California Edison. It did not include any public power agencies within the mandate for retail access. Public power provides a significant amount of delivered electricity in the state and includes the largest public power agency in the US, Los Angeles Department of Water and Power as well as a number of politically powerful irrigation districts. The capital of California, Sacramento, is served by the Sacramento Municipal Utility District, also not included under the legislation.

\(^6\) There were four zones but two, Humbolt (a voltage pocket) and San Francisco (a load pocket) could hardly be seen relative to the break at “Path 15.”
operator and the rigid rules for submission of balance (energy in equals energy out) schedules and ancillary services caused inefficiencies and gaming in particular elements of the market.

The California ISO has now undertaken to reform the congestion management system due to a number of flaws that collectively resulted in locationally inaccurate price signals to market participants and the excessive socialization of out-of-market congestion costs. These problems evolved mostly due to poor implementation rather than flaws in the basic design. Some of these shortcomings were due to the lack of implementation of a number of the original design features and others with inadequate detail in the initial market model. There are a wide range of opinions on the California market flaws, but, generally, the following are acknowledged as being critical:

- The initial market design had a poor representation of the transmission system in the forward market. The California market initially consisted of two pricing zones (which recently evolved into three) with one interface between them. The market designers determined that only this interface and the interties with neighboring regions would have scarcity value of commercial significance, and therefore established tradable transmission rights only on these interties. All other transmission congestion within California was assumed to be minor and therefore spread across all users in the corresponding zone. Market participants would see only two prices within California, one in each zone.\(^7\) This design turned out to be too simplistic, and over time significant intra-zonal congestion resulted. Further, new generation did not receive sufficiently accurate price signals to have any incentive to locate where they would relieve constraints, and therefore new generation. Consequently, rather than alleviating congestion, congestion was often created and thereby exacerbated economic market power.

- The original design specified the performance of both intra-zonal and inter-zonal day-ahead congestion management. Instead, only the inter-zonal day-ahead congestion was implemented, leaving the possibility for significant intra-zonal congestion to pass unnoticed until real-time. Had the original design been implemented, financially binding redispatch could have been incorporated into schedules and intra-zonal congestion could have been mitigated even with the two-zone model.

- The design of real-time congestion management did not incorporate the effectiveness of units in relieving transmission constraints. This contributed to inefficient, and therefore more costly, intra-zonal congestion management.

- Intra-zonal congestion management did not distinguish between competitive and non-competitive situations. The ISO dispatched reliability-must-run (RMR) units to alleviate intra-zonal congestion and local market power. These costs did not get factored into the locational price signal and also resulted in broad cost allocation which resulted in artificially high price signals and the creation of incorrect incentives for new generation.

- Finally, market participants did not have the information or the tools to be able to identify and enhance trading opportunities among themselves. The information required included the ISO's congestion management protocols, so that participants could independently evaluate the expectation of congestion. This would include the ability to trade in energy and ancillary services between Scheduling Coordinators (SCs) – remembering that the rules required all schedules to be balanced at all times – and thereby to provide adjustment bids on these inter-SC trades. Currently, the market separation rule requires that during day-ahead congestion management, the ISO may create adjustments only within an SC's portfolio, such that their schedules always remain in balance. The ability to trade and/or balance between SCs would add significantly to the economic efficiency of the California market.

Arguably several of these problems could be fixed, while retaining the basic market design, by improving the transmission system representation (through more zones) and improving the congestion management algorithms. The critical question is whether the imperfections that are perceived in the market can be repaired with the current structure or whether they require starting over. The argument has the flavor of “throwing the baby out with the bath water” in that the concept of the separation of the forward market from the operational requirements was desirable. The implementation was flawed at the point of the hand-off of the forward market and the scheduling function to the Cal ISO, the system operator.

\(^7\) The methodology for determining zones and the commercially significant interfaces was also criticized as being arbitrary and flawed. Interties were deemed to be commercially significant if their congestion costs were at least 5 percent of their embedded costs. The costs incorporated in this calculation did not include certain non-trivial costs, such as the RMR-related costs described in the discussion.
The PJM market, example 2

The PJM market structure is touted as the answer to all problems with regard to the operation of efficient electricity markets. It is organized around a central market maker and system operator that receives bids from all generators (and eventually the demand side) and produces an efficient scheduling mechanism on a 5 minute by 5 minute basis. The outcome of the PJM process is the calculation of 5 minute locational marginal costs or prices for each of the better than 2000 electrical nodes under the control of the PJM operator.

To sell or purchase energy in PJM required only that the seller receive the locational price at the point of delivery to the grid and the buyer pay the price at the point of withdrawal from the grid. The difference between the locational cost at the point of delivery and that at the point of withdrawal represented the marginal cost / value of transmission. In this manner even bilateral contracts, for which the price of energy was not known by the PJM operator, can be charged the marginal cost for the transmission. To protect against price volatility and to provide a delivery hedge, a complex system of financial transmission rights was established by which transmission users could acquire a financial right to the revenues generated charging the difference between the point of injection and the point of withdrawal. As an example, assume the user were at B but its supply were at A, and it had agreed in advance to pay A 7 cents per kWh as a flat fee for delivery. At the time of delivery the locational price at A was 10 cents and the locational price at B was 15 cents. The buyer would have to pay its contract to A of 7 cents and in addition to pay the difference between A and B of 5 cents to the transmission operator for the marginal cost of the transmission. To hedge against this uncertain cost, the buyer at B could have purchased a Fixed Transmission Right (FTR) to receive any revenues for transactions between the pair of nodes, A and B. Under these circumstances, in the above example, B would have paid the 7 cents to A for energy and then paid the additional 5 cents to the transmission operator for transmission but then received 5 cents back from the transmission operator because B owned the FTRs for the transaction. FTRs represent a highly significant element of the procedures within PJM.

At the time at which the market was initiated it was recognized that 2000 nodes would not provide for any liquidity in the market. Consequently, two “trading hubs” were created with a calculated price in each hub that was the unweighted average of a prespecified set of nodes throughout the system. PJM West and PJM East. PJM West quickly became the most liquid paper market in the US while there was, effectively, no trading at PJM East.

On the surface it would appear that PJM is the perfect market. Critics have pointed out, however, that there are a number of flaws. The most significant of these is that while there is a liquid paper market at the western hub, there is virtually no forward market for delivered energy at any point in the east of PJM. There are two explanations. The first, the method of allocation of FTRs is fatally flawed in that they are presently being allocated to the formerly vertically integrated retail suppliers. The second, the locational prices as seen in the 2000 node model are so idiosyncratic and subject to random events in the transmission system, that it is not possible to effectively use the FTRs as a hedging mechanism. Suppliers who might bid for delivery at a location in the East are loath to bid anything short of a value that would recover their delivery costs should the unexpected occur.

There are a number of other significant design issues as well. The LMP system is designed to provide to market participants all the information required both for real-time system operation and for long-run investment decisions for generation and transmission. FTRs are intended to provide transmission customers who have firm transmission service a financial protection against incurring transmission congestion charges. This combination of LMP for efficient energy pricing and FTRs for the efficient allocation of congestion charges is intended to result in robust competition in both the short-run and forward markets. In reality the LMP/FTR market structure falls far short of these theoretical objectives. Some of these shortcomings are:

- Insufficient transmission expansion.
- Unequal access to transmission rights (FTRs).
- An inefficient allocation of congestion costs (when FTRs do not go to those who value them the most), and
- A neglected and very weak forward market structure.

The first shortcoming is revealed through the lack of sufficient transmission expansion. While in theory the LMP model would provide the price signals needed to expand transmission, in practice those signals have proven to be either muted or perverse. They are muted because a single investor finds it impossible to recover the cost of the transmission investment from the available mechanisms. The LMP price signals are perverse because transmission remains a strategic asset which can be used to provide positive revenues to affiliates of transmission owners and negative impacts on their competitors in the market.

With respect to FTRs and the allocation of congestion costs, the PJM implementation demonstrates that neither

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*As of September 27, 2000 the FERC has agreed to a change in the rules which will require that all FTRs now be auctioned on an annual basis.*
equity nor economic efficiency are obtained. For equity, FTRs would be allocated to all network customers in proportion to their MW reservations. However, in order to obtain FTRs in PJM, a loophole exists that requires customers to designate the specific network resource that is serving their load. Customers who are unable to point to network resources are unfortunately blocked from obtaining FTRs and so are not hedged against congestion charges. Second, economic efficiency would dictate that the FTRs go to those participants that value them most highly, yet in PJM they are allocated according to historical precedence without the involvement of market forces.

Though LMP was intended to facilitate trading in forward markets, after three years of effort PJM only supports a single trading center - the Western Trading Hub. The chronic congestion between regions and its poor management under the LMP/FTR system has rendered the Eastern hub meaningless to the forward markets. A simple review of price quotes at various trading hubs (or the lack thereof), in publications such as Megawatt Daily, Power Markets Week, and Energy Market Report, demonstrates this finding. The development of a forward market is further frustrated by the inability under the FTR system to trade transmission, in a meaningful way, separately from generation.

The hybrid model

Why is the hybrid a necessary outcome? The answer is clear that neither model alone allows for both the creation of a forward market with a stable delivery system. The imperfections in the first model can be seen in its application in California. This approach did not pay sufficient attention to the potential for congestion within the pricing zones in the state. The result has been increased costs that must be averaged across all users. Imperfections are also seen in the second model as applied in PJM. While assuring that no costs will be averaged, it has not allowed for the creation of a liquid forward market for delivered energy. Its proponents claim that the existence of a liquid market at the Western Trading Hub is sufficient, but the selling players in the market will not take the risk of delivery to the eastern markets (the largest markets) because they are unable to lock in a price for transmission (delivery) of the product. There are few, if any, useful delivery rights available in either the primary or the secondary markets.

While calling the proposed model a hybrid may be a misnomer, it is a useful paradigm for moving forward in the development of liquid regional energy markets. The key to any hybrid is the recognition that there are two distinct problems that must be solved and that the handling of congestion – the congestion management system (CMS) – is at the core of the interface between these two problems. Turning electricity into a commodity that can be traded is not trivial. The discussion that follows provides, it is argued, a structural alternative that captures the best of both worlds, a simplified trading structure that can provide for forward contracting of delivered energy and an efficient operating mechanism that can send locationally accurate price signals to all players in real time.

The forward market

While electricity is acknowledged to be a product produced and consumed at the same time (not storable), in the forward market it need be no different from any other commodity. The objective of such a forward market is to provide a means of hedging risk in both consumption and production. The same conditions apply to natural gas (a highly similar product) and corn. The forward market trades the commodity as a financial product, anchored in the knowledge that the first player in the chain is the producer, the last is the consumer, and in between the product may trade multiple times. The spot market provides the final price at the time of delivery and represents the realization of the expected prices of all of the prior trades. Some of the traders may guess high on the realization and some low, but the key is that the market players, looking forward in time, chose to transact, each for its own reason and each for its own perceived benefit while taking its risk profile into careful consideration.

The delivery of electricity diverts from traditional commodities in that it is traditionally considered to be a product that is produced and consumed at the same instant (i.e., it is not storable). While this is technically correct from the physical perspective of the electrical engineer/operator, it is not the case from a market perspective. Electricity is actually stored as a variety of intermediate products e.g., as municipal water stored in water towers. Nonetheless, it is clear that in real time there is a need for a mechanism to assure that the energy contracted for in the forward market is deliverable in a manner that will assure the integrity of the delivery system (stability).

The interface

The question then becomes how to create a forward market that will function efficiently and is “deliverable” while assuring the physical operation of the system. The answer lies in defining, carefully and consistently, the interface between the forward market and real-time operating mechanics. This definition must focus on the question of the management of actual or potential congestion on the transmission system. All the
discussion surrounding this congestion issue, in fact, really reflects the essential underlying debate between the two models as to how to operate and control the market for electricity.

The polarization of the debate has led to the need to develop a “compromise” or a “hybrid” model. It is now recognized in the U.S. that such an alternative needs to allow for a robust forward market as well as, an accurate, cost allocative mechanism for real-time operations. Indications of this recognition can be found in the hybrid efforts of ERCOT (Texas), SPP (Oklahoma and Nebraska), the MidWest ISO (Minnesota to Ohio), and activities in Florida, which are aimed at responding to the FERC Regional Transmission Organization (FERC Order No. 2000) requirements.

The CMS

The purpose of the hybrid proposal is to develop a market for transmission capacity that will foster liquid, competitive wholesale and retail markets and provide locational pricing signals for efficient expansion of the grid. It represents a market structure in which the key element is a flow-based congestion management system – Real Flow – that establishes a market for physical transmission property rights called flowrights (FRs) and that internalizes the physics of the electric grid into the market design. The hybrid is additionally designed to permit use of the existing control area infrastructure in loose pools and to institute a Regional Transmission Organization (RTO) that will coordinate the reliable operation of the grid, but play a minimal role in market operations. The hybrid can also be scaled to operate seamlessly in multiple RTOs across, for instance, the Eastern or Western Interconnections.

The premise of the hybrid is that congestion can be managed in a significant part, preemptively, in forward markets without any RTO intervention. This is accomplished by selecting a set of commercially significant flowgates (CSFs), whose capacities market participants purchase and trade in the form of flowrights (FRs). FRs are defined by the RTO and sold off on a pre agreed upon schedule in a primary market or primary auction. Commercial markets are then the site of secondary trading in FRs. Participants trading energy purchase FRs based on the flow impacts of their transactions on the CSFs to hedge congestion risk. This aligns market activity with the physics of the grid. Market participants may submit balanced or unbalanced schedules a day ahead of their use. Changes are permitted until the close of the hourly market. This market design provides a firm forward price associated with a tradable right for transportation. The forward market is thus dealing with and valuing congestion at pre selected points (CSFs), hence the concept of preemptive congestion management.

The hybrid permits commercial entities to operate exchanges for energy, transmission (the secondary market) and ancillary services where market participants will trade. The commercial transactions of the forward market operate independent of the RTO except in so much as the RTO can make additional FRs available to the market. The forward market for electricity takes on the characteristics of all other forward commodity markets. The product is traded in a financial transaction that at all times is potentially deliverable (i.e., the participants in the transaction have the ability to close the transaction with all three components firmly committed: the source, the transmission path, and the sink). At the same time, prior to the day-ahead scheduling requirement, these same elements – generation, transmission and demand - may be traded independently.

Trading and market rules

The key elements of the hybrid market structure are, as stated above, the rules and realities of passing from the forward market, with its acknowledged simplifications, to a real-time operating mechanism that can assure delivery to end users. To satisfy these conditions requires, initially, a set of trading and market rules proposed with the following conditions.

First, the forward market closes a day ahead. The time period has been chosen to match the general scheduling time frame of today’s operators. At this point in time, the requirement is that all transactions that are scheduled be capable of going to delivery. The

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9 This CMS creates a commercial model based on an approximation of the physical transmission system. This proposed hybrid is based on the work of a breadth of individuals and group. The initial concepts of a flow-based congestion control system was called “flow-bat” and introduced by Paul Barber of Citizens Energy Corporation. The current discussion was initiated by the work of Ed Cazalet and his colleagues at the Automated Power Exchange (APX), a California-based commercial power exchange software corporation.

10 A flowgate represents a point (or coordinated multiple points) of physical connection within the power system that represent both a monitoring point and a point of potential congestion in the system. A Commercially Significant Flowgate is being defined as a flowgate that, when constrained, has price differentials on the two sides that are of sufficient magnitude to alter the economics of commercial transactions. The precise definition will be required for each region that adopts this methodology.

11 The quantity of flowrights required for any transactions can be calculated using the NERC Transmission Distribution Factors matrix which quantifies the proportion of energy that flows over any monitored element in the transmission system.

12 The choice of the time of closing of the forward market (and the submission of fixed schedules) is a market design choice. The choice described here represents a structure that can be implemented within the procedures of most current US utility practices.
transactions can be balanced (energy in equals energy out plus losses) or it can be unbalanced or simply a bid for either generation supplied to the market or demand from the market. The key point is that when FR purchases are required there is no anticipated congestion in the schedules that are handed to the operator at this time.

Second, the adjustment market occurs between the time of closure of the forward market and the real-time operating period. During the adjustment market period the schedules submitted may be modified and new schedules added.

Third, the real-time operating window begins at some point prior to the hour in which the energy is to be delivered. This may be as much as an hour and as little as five minutes prior to the hour. During this time period the operator is in full control of the system and uses voluntary incremental and decremental bids (incs. and decs.) for both the supply (generation) and demand (consumers) as well as any unbalanced energy schedules as a means of balancing the system in real time. The system operator uses the rules of locational-based marginal pricing to operate the system, minimizing the total cost of real-time operations, while assuring that the schedules submitted are delivered. The operator calculates and reports a locational price (LP) for every monitored node in the system.

These data are then used in calculating imbalance charges as well as charges for uncovered transactions. It is critical to note that any congestion that arises due to unanticipated outages in the system is adjusted for in real time by the operator through the cost minimization structure described above.

In addition, after the close of the real-time operating window, imbalances (the difference between scheduled and actual deliveries and demands) that occurred during operations are then posted and open to trading between potentially offsetting parties. Any trading requires that the parties account for locational differences in both generation and demand and thus account for the price of congestion in their transaction. Any residual imbalances are charged (or paid) by the RTO at the LMP in effect at the time of the transaction.

For any transaction that has secured all of the necessary flowrights in advance of real time, scheduled those rights with a balanced schedule and then held schedule, there are no additional charges for transmission in real time. Under these circumstances, should additional congestion arise, the transmission user is fully sheltered or hedged from these costs and any such costs are uplifted. For transactions that are not fully covered the calculation is different. There are two conditions that can exist with regard to coverage.

- The transaction has flowrights on all of the required CSFs but not in the correct proportion. Under these conditions the transaction is really two transactions, the first fully covered and balanced and the second a partially or completely uncovered transaction.
- The transaction has flowrights on some but not all of the required CSFs.

Under both of these conditions the residual, uncovered portion of the transaction will be charged based on the locational prices for the time of the transaction. The calculation procedure will be the following:

1. Calculate the full locational cost of the uncovered and/or unbalanced component of the transaction.
2. For each CSF, the RTO calculates the shadow price of the CSF.
3. The transaction is then credited for the shadow price times the quantity of flowrights held.
4. The amount due to the RTO for uncovered and unbalanced transactions is equal to the net of the full LP for the transaction minus the operational value of the flowrights held.

Using this procedure for settlement assures that the following conditions pertain:
- All partially or completely uncovered transactions carry the full cost of any real time congestion;
- All covered transactions are fully hedged; and
- All calculations are carried out based on the real time transmission Distribution Factor matrix (TDF) and the real-time costs of operations.

There is one issue that should be recognized. For the second type of partially covered transaction, that does not have some coverage on each of the needed CSFs, the transaction will cover all of the congestion costs, i.e., none will be uplifted. This is the case because none of the transaction fulfills the requirement of being fully covered.

The hybrid model: Is this a solution to the issues seen in both market structures?

The benefits of the hybrid as described above are obvious: the assurance of a liquid forward market and locationally specific real-time operations. The disadvantage is that there is some minimal uplift associated with the requirement that transmission, when fully covered with FRs, is financially firm regardless of any emergency changes in the transmission system.

What might the impact be on the two examples, California and PJM? For California the answer may lie predominantly in the manner in which a more complete

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13 This practice of averaging and charging to all customers is referred to as an “uplift” based on the vocabulary developed in the UK, or as “socialization” of costs in some literature in the US.
representation of the transmission system will improve the price signals and reduce gaming in the market. The real-time operations require additional specificity. At the same time, however, improving the detail in the forward market representation of the transmission system will also provide an additional incentive for retail suppliers to trade in the forward market. Many of the issues in consumers seeing high price volatility in recent months have been blamed on the immaturity of the forward market and the fact that there appear to be disincentives to the existing utilities using it.

PJM is a separate case. The PJM real-time market appears to be working well in an electrical system that is exceedingly complex. At the same time the lack of liquidity for delivered product in the forward market makes PJM consumers at least as vulnerable as California consumers to price spikes when supplies are short. When all of the energy is being traded and thereby priced at short run marginal cost (with few if any long-term forward hedges), consumers feel the full brunt of the price volatility. Even when the annual average price may not go up, if the hourly prices rise by a factor of 10, it is a news worthy event.

The conclusion one reaches is that the operational characteristics of both California and PJM can be enhanced with some attention to the marriage of a liquid, deliverable forward market with an accurate real-time operational accounting system.

Conclusion

In summary, the electric power industry in the United States has been moving forward along a poorly lit path. Different models have been proposed and implemented. Each has had strengths and weaknesses but neither has been perfect under all circumstances. The U.S. model of “allowing a thousand flowers to bloom” has clearly allowed options to emerge, but the time has come to try to find a model that is at minimum a logical transition and at best an end game for the market structure of what is arguably the key infrastructure industry in the United States today. The hybrid model discussed here begins to lay the foundation for the development of both a liquid forward market and a stable delivery system.