UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

Inquiry Concerning the Commission's	)	
Policy on Independent System Operators	)	Docket No. PL98-5-000

FERC POLICY ON INDEPENDENT SYSTEM OPERATORS: SUPPLEMENTAL COMMENTS

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May 1, 1998

INTRODUCTION

The Commission raised many important questions for consideration in this inquiry. Presumably the extensive and difficult issues cannot be disposed of within the constraints of a two day public conference, even accompanied by a few pages of comments. Hence, my approach is to emphasize the conference as neither the beginning nor the end of the conversation, but as a major milestone in the effort to move forward with the development of open access and competitive electricity markets. Relatively few of the Commission's explicit or implied questions lend themselves to a single answer. Much has been learned in the development of open access and the design of new market institutions, and tradeoffs among various objectives are, to a degree, inevitable. However, the realities of the electricity system impose certain constraints and consistency requirements that serve to narrow the choices that the Commission can or should make.

Here I respond to the request for supplemental comments addressing the Commission's questions about transmission pricing and other issues discussed at the two day session of April 15-16, 1998.

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[1] These supplemental comments expand on the oral testimony provided at the FERC Public Conference Concerning the Commission's Policy on Independent System Operators, April 16, 1998. William W. Hogan is the Lucius N. Littauer Professor of Public Policy and Administration, John F. Kennedy School of Government, Harvard University, and Senior Advisor, Putnam, Hayes & Bartlett, Inc. These comments draw on work for the Harvard Electricity Policy Group and the Harvard-Japan Project on Energy and the Environment. The author is or has been a consultant on electric market reform and transmission issues for British National Grid Company, General Public Utilities Corporation (and the Supporting Companies of PJM), Duquesne Light Company, Electricity Corporation of New Zealand, National Independent Energy Producers, New York Power Pool, New York Utilities Collaborative, Niagara Mohawk Corporation, PJM Office of Interconnection, San Diego Gas & Electric Corporation, Trans Power of New Zealand, Williams Energy Group, and Wisconsin Electric Power Company. The views presented here are not necessarily attributable to any of those mentioned, and any remaining errors are solely the responsibility of the author.

MANDATES AND SYSTEM OPERATIONS

The development of Independent System Operators (ISOs) has proceeded steadily in the worldwide restructuring of electricity markets. There are significant advantages in this approach. One of the few clear conclusions is that there must be a system operator coordinating use of the transmission system. This control of the use of the transmission grid means control of the dispatch, at least at the margin, because adjusting the dispatch is the principal (or, in some cases, only) means of affecting the flow of power on the grid. That this system operator should also be independent of the existing electric utilities and other market participants is attractive in its simplicity in achieving equal treatment of all market participants. The ISO provides an essential service, but does not compete in the energy market.

There is a great deal of debate about the Commission's authority to mandate membership in an ISO, the need for such mandates, and the possibility that ISOs might be only a transitional arrangement. For example, participants at the conference discussed the notion that ownership of the wires (a GRIDCO) combined with system operations (an SO) could produce an independent TRANSCO that would be different from an ISO, or an alternative that might be precluded by an ISO.

On balance, I see the discussion of the TRANSCO option as a distraction from the main questions that should concern the Commission. Some of the comments at the conference could be interpreted as saying that mere establishment of a for-profit TRANSCO would dispense with the difficulties of evaluating the pricing and access rules for transmission and system operations. Apparently the argument was that through some type of incentive regulation, an independent TRANSCO would support a non-discriminatory, competitive electricity market that meets the Commission's goals. While we should keep our minds open to this possibility, we ought recognize that there is no known system of incentive regulation that could achieve this panacea. Such a brilliant innovation would be truly remarkable. The difficulties to be overcome would begin with the same set of problems that complicate the process of setting the rules for system operation. At the core is the uncomfortable reality that there is no simple definition of the output of the transmission system. Efficient transmission is far more than throughput--it is a complex service with many dimensions and substantial network interactions. Were this not true, there would probably be no need for a system operator in the first place.

An independent TRANSCO may be attractive, and it could be the next stage or the end stage. But developing incentive regulation for a TRANSCO will be a major challenge, pregnant with the danger that we could make the situation worse. The very complexities that dictate the need for a system operator mean that it will not be an easy matter to structure the rules for system operations, nor would it be easy to structure incentives for a monopoly to discover the rules on its own. Providing appropriate incentives for the transmission system is a major difficulty in restructured electricity systems around the world. Some problems might be different, such as the approach to providing incentives for grid maintenance and expansion,[2] but all the puzzles about the operating rules would appear again in this new guise. It is not likely that the TRANSCO incentives could be developed so easily as to leave design of the system operation rules and pricing to the TRANSCO monopoly alone.

Far more likely is the outcome described by Fiona Woolf in her characterization of the TRANSCOs she has worked with in other countries.[3] Somewhere in the company will be a system operator that must be "ringed fenced" from the rest of the corporation, to have its own independent rules and pricing structures that support the public interest in a competitive market, not only the private interests of the monopoly TRANSCO. The Commission will face the task of evaluating and approving the rules for pricing and access. And this applies to the TRANSCOs that are embedded in the vertically integrated utilities, as well as to new independent TRANSCOs that might be divested from the utilities.

Whatever decision the Commission makes about its own authority and the desirability of mandating ISO membership, therefore, the TRANSCO option should be viewed as a complement and not a competitor. It should not deflect the Commission from the hard task of developing further the rules for pricing and access through system operations. It is clear that the Commission will have a major impact in its prescriptions concerning the appropriate structure and role of (I)SOs, whether independent or not, whether a TRANSCO or not. And the Commission should be more prescriptive. There is great confusion on this matter and the Commission is the most likely candidate for providing coherent guidance that would advance its objectives and avoid the worst mistakes.

FLEXIBILITY AND PRICING

One example of the confusion is in the parallel activities devoted to the discussion of ISOs, OASIS for transmission scheduling, NERC security coordinators for transmission line loading relief, and the Commission's own Capacity Reservation Tariff (CRT) proposals. Although these packages tend to be discussed in isolation, there is substantial overlap in that they all provide alternative approaches for the same core problem: rationing use of scarce transmission capacity. Furthermore, the approaches tend to be mutually inconsistent: some ISO models include bid-based economic dispatch; OASIS (in practice, if not in theory) is built around the flawed contract-path model; NERC's tagging rules and line loading relief procedures struggle with the contract path fiction, power flow realities, and the commercial complications of administrative curtailments; the CRT would move all the way to a point-to-point reservation system with economic rationing. We can't do all of these at the same time. And the attendant

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[2] William W. Hogan, "Transmission Investment and Competitive Electricity Markets," Center for Business and Government, Harvard University, April 1998.

[3] Fiona Woolf, Cameron McKenna, comments on Panel 3, "Regulation, Governance, and Independence," FERC Public Conference Concerning the Commission's Policy on Independent System Operators, April 16, 1998.

problems of coordinating trade across regions may be some of the most vexing for the Commission and the competitive market.

The unwelcome news for the Commission is that the hard problem of allocating scarce transmission capacity is made much more difficult by the move to competitive markets. In effect, we have taken the black box of the vertically integrated industry, opened it, and unbundled control of the various gears. In order for the system to work, however, the gears not only have to turn--they have to mesh. This is especially true in the very short-run, as we move closer to real time operations.

Everyone wants non-discrimination and the maximum possible degree of flexibility for market participants. But to provide this flexibility, and make sure the gears mesh, it will be necessary to align the incentives of the participants with the success of the overall market. Either the incentives must match the system realities, or the ISO pricing and access rules will be restrictive and dictate customer choices. Furthermore, the role of the ISO inevitably will encompass both reliability and commercial issues. The supposed distinction between reliability and economics is a mirage which will provide no comfort in practice. The nature of the electric grid dictates that decisions motivated by reliability concerns will have substantial commercial impacts, especially when the system is constrained and the decisions matter most. The only issue is the degree to which we will be explicit about the interaction between reliability and economics, in order to improve both efficiency and transparency.

Cursory treatment of the connection between usage prices and operating decisions should be among the major casualties of the electricity restructuring process. If customers have flexibility in the choice of generation, spot purchases, bilateral transactions, and so on--then prices matter and prices should reflect marginal cost impacts. In large part, control of operating decisions is moving from engineers motivated by principles of efficiency, to market participants motivated by profit. This is a major purpose of electricity restructuring--to change the locus of such key decisions. If we want the market to be guided by prices, and we expect and intend for people to take these prices seriously, it becomes important to follow the usual advice to "get the prices right."[4]

GETTING THE PRICES RIGHT IN PJM

The debate over transmission usage and the earlier experiment with a zonal transmission pricing approach in the Pennsylvania-New Jersey-Maryland Interconnection (PJM) provide a stark illustration of the difficulty and the challenge. In March of 1997, the Commission approved an interim transmission access and pricing system to operate in conjunction with a real-time spot market coordinated through the PJM ISO. Faced with opposition to a full locational pricing and congestion charging mechanism for actual use of the

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[4] William W. Hogan, "Independent System Operator: Pricing and Flexibility in a Competitive Electricity Market," Center for Business and Government, Harvard University, February 1998.

system, the Commission endorsed the locational approach in principle but adopted temporarily an alternative model proposed by Philadelphia Electric Company (PECO) and others. The PECO approach minimized the importance of transmission congestion and rejected the locational pricing model as too complicated and unnecessary. Instead, the PECO model would treat the entire PJM system as a single zone.

In essence, the PECO model priced all transactions through the spot-market at the "unconstrained" price, based on a hypothetical dispatch. To the extent that the actual dispatch encountered transmission constraints, the PECO model would pay the more expensive generators to run and average these congestion costs over all users.

The model included two other notable features. First, in the face of transmission congestion, the generators that were constrained not to run would be paid nothing, even though they had bids below the "unconstrained price." There was objection to adopting any system that depended on paying generators not to run, with the attendant discrimination and perverse incentive effects. Second, market participants had the option to schedule bilateral transactions separate from the bid-based economic dispatch of the ISO, with a separate payment for their share of the total congestion cost. This flexibility to use bilateral transactions or to participate in the coordinated spot market was a major design objective not to be abandoned.

This pricing system is representative of a zonal approach, and has much in common with zonal systems adopted elsewhere in the world.[5] However, should the system become constrained, the two exceptional features noted above would create a powerful and perverse incentive. If there were no transmission constraints, there would be no transmission congestion and everything would work as with the locational pricing system. But when congestion appeared, everything would be different. The supporters of the zonal approach argued that the total cost of congestion would be small, summed over the year, and therefore any inefficiencies could be safely ignored.

Ignoring a difference between prices and marginal costs is a safe practice in a regulated world without flexibility and choice. The incentives don't matter and the small costs get lost in the larger system. It can work inside the closed black box. But the cost of ignoring a gap between prices and marginal costs in the world of choice can be large indeed. Witness the events when the PJM system became constrained, starting in June of 1997.

The data for a representative constrained dispatch found the marginal cost in eastern PJM at about \$89 per MWh, when at the same time the marginal cost in the west was \$12 per Mwh. At the same time, the "unconstrained" price for the "One Zone" (Oz) was approximately \$29 per MWh. The incentives were clear. A customer could buy from the spot-market dispatch at \$29, or it could arrange a bilateral transaction with a constrained-off generator in the west at

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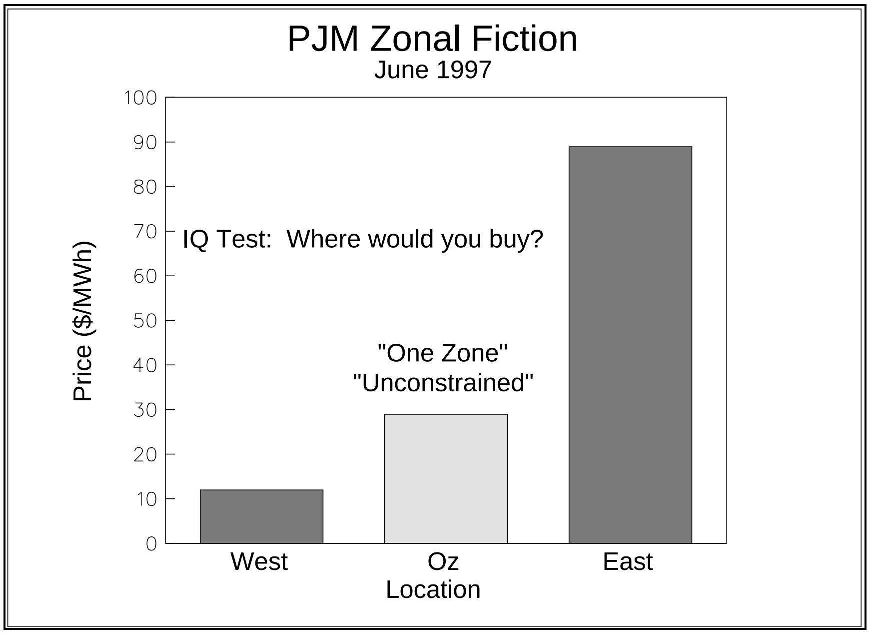
[5] Here the issue is pricing for transmission congestion. The recovery of embedded costs of transmission investment through access charges is a separate matter that is amenable to zonal approach.



a price closer to $12.[6] The small average congestion cost would be the same either way, and would not affect the choice. The choice, therefore, presented a low-level IQ test.

Faced with these incentives, constrained-off generators passed the IQ test. They quickly arranged bilateral transactions and scheduled their power for delivery. This, in turn, required the ISO to constrain the output from some other generator, who would then follow the same direct path to a bilateral schedule rather than sit idle and collect nothing. Soon the ISO had no more controllable generating units with which to manage the transmission constraints. Unable to fix the perverse pricing incentives, the ISO resorted to administrative mechanisms to prohibit bilateral transactions or declare a "minimum" generation emergency during the peak generation period. In effect, while restructuring to facilitate a market, the unintended consequences of superficially simple pricing spawned administrative rules to prohibit the market from responding to the price incentives when they mattered most. Shackled with inconsistent pricing rules, the ISO had to resort to direct preemption of market choices.

The point was made in a dramatic way. The important issue is not the total cost of congestion, which may be small on average. The point is the incentives at the margin when the system is constrained. In designing the rules for transmission pricing and access for a competitive market, it matters little what the rules are for periods when the system is unconstrained. The important question is how the rules deal with the market when the system is constrained. Even if the total cost of congestion might be modest over the year, the gap between $29 and $12, or $89 and $12, is more than sufficient to get the attention of market participants. Given the margins in this business, they will change their behavior for $1. And the changes in behavior can substantially affect system operations; in fact, the whole point of electricity restructuring is that changes in behavior can affect system operations and lead to different patterns of electricity use and investment.

In the locational pricing system, the perverse incentives would not arise. Given the same facts as above, the locational prices would equal the marginal costs. Those customers

[6] Power Markets Week, September 1, 1997, p. 13.

purchasing power from the spot market in the east would have seen $89 as the price. True, they could have arranged a bilateral transaction with a generator in the west, paying $12 for the energy. But they would then face a transmission charge of ($77=$89-$12), making them indifferent at the margin, just as intended. Likewise, customers in the west would pay $12 and have no incentive to change. Every generator would be producing at its short-run profit maximizing output, given the prices. The market equilibrium would support the necessary dispatch in the presence of the transmission constraints. Spot-market transactions and bilateral schedules would be compatible. Flexibility would be allowed and reliability maintained consistent with the choices of the market participants.

The PJM ISO was fully aware of the perverse incentives of zonal congestion pricing and the problems they created, but without the authority to change the pricing rules it had no alternative but to restrict the market.

Faced with this reality, the Commission acted to approve the locational pricing system that became operational in PJM at the beginning of April of 1998. The developing experience with this full locational pricing of the use of scarce transmission capacity deserves close study by the Commission and all SOs.[7]

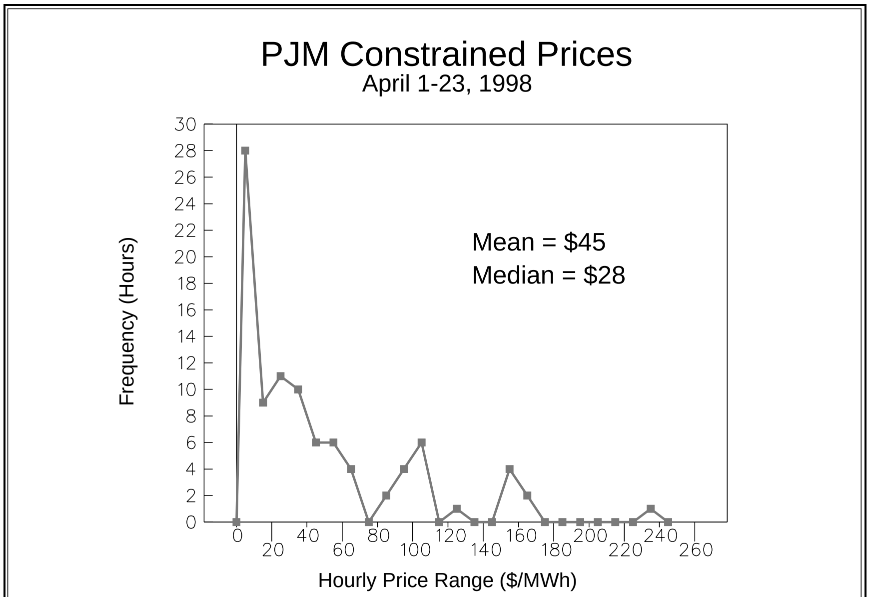
Although these are the early days, the new pricing mechanism is working as anticipated by the ISO and the supporters of the approach, but apparently not as anticipated by many who dismissed the importance of this issue. The month of April is not typically a highly constrained period in PJM, and it would not have been impossible for the first days of locational pricing to have been boring. With no constraints, the locational prices, ignoring losses, would be identical at all locations. The cost of transmission between points--the difference in the locational prices--would have been zero. Nothing much might have happened until we approached the summer, when congestion would be more likely, as for the previous year.

In the event for the first 23 days of operation, the results were not boring, at least to me. The system experienced transmission constraints, locational prices separated, and the opportunity cost of transmission was quite large. The lowest locational prices were sometimes negative, reflecting the value of counterflow in the system where it would be cheaper to pay participants to take power at some locations and so relieve transmission constraints. The highest locational prices were very large, much larger than the marginal cost of the most expensive plant, reflecting the need to simultaneously increase output from expensive plants and decrease output from cheap plants, just to meet a increment of load at a constrained location. Over all hours, the low price was -$45 at 1500 hours on April 18 at "JACK PS," and the highest price was $232 at 1100 hours on April 16 at "SADDLEBR," both locations being in the Public Service territory. As large a range as this is, it is smaller than the range in marginal costs that occurred before the

[7] The data available at the time of this writing and used here were taken from the PJM web site at www.pjm.com for the period April 1 through April 23, 1998.

prices were charged when users could ignore the cost of congestion.[8]

The contemporaneous difference in locational prices, which is the price of transmission, has been large as well. If we take the $1 per MWh standard as an arbitrary threshold, the range of highest to lowest price across locations exceeded the threshold for 94 hours, or approximately 17% of the time. As shown in the accompanying figure, the frequency distribution of the price range in constrained hours is skewed, with a median hourly price range at $28 and a mean of $45. When the system is constrained and the market incentives matter the most, the marginal costs of transmission can be large.



Maximum difference in locational prices for constrained hours.

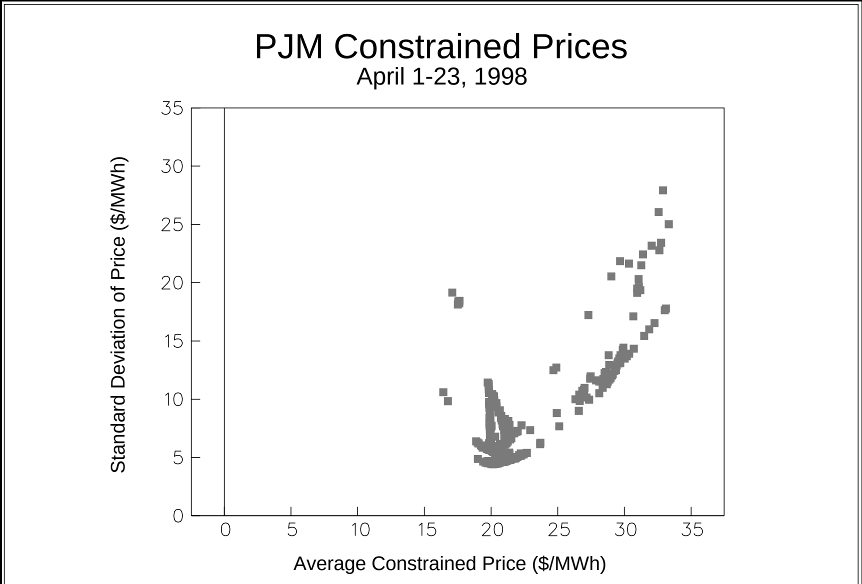
The evidence shows many things. For example, calculating and reporting of the locational prices for each point on the grid are not an especially complex tasks, at least for the system operator who has the necessary information available. The prices can be available every five minutes on the Internet. Faced with these prices, the market participants adjust their behavior, just as intended. The transition was not painless, especially for those who ignored many warnings and entered into "sellers choice" contracts that gave the seller the maximum theoretical financial advantage for relieving congestion. Presumably, this form of contract will disappear, or be properly priced in the future, and the market participants will become more attuned to the use of fixed transmission rights to hedge much of the cost of congestion. But market participants who rely on the spot market and are not prepared to pay for congestion hedges, will see the price signals that align their incentives with the reality of system operations.

What about aggregating PJM into a few zones, if not just "Oz"? The PJM ISO is reporting prices for approximately 2000 locations. This is a convenient way to represent the data, because it is how the data are organized for actual system operations. However, some of these locations are really just multiple units at the same point on the grid, and would necessarily have the same prices in most circumstances. For other points on the grid, the zonal argument is that the locational differences would be minor, and could be represented by a relatively few zones.

[8] On March 26, 1998, at 2200 hours, the difference between the highest to the lowest marginal cost was almost $400.

This view has been subjected to a test over these first days of operation.

April is a period that could have been a relatively unconstrained, presenting a low hurdle for the zonal approach. The choice of the appropriate zones would not be an easy matter, and there is some ambiguity in clustering criteria. However, one simple way to summarize the data would be to examine the average and the variation of prices at different locations during constrained hours. If two locations always have the same prices, then the two average prices would be the same and the two standard deviations of the prices would be the same. These conditions would be necessary, but not sufficient, for the prices to be the same at the two locations. Hence, this straightforward calculation gives a lower bound on the number of different locations with sometimes unique prices.



Mean and standard deviation over 94 constrained hours at different locations.

The accompanying figure plots the data on average price and standard deviation of price across 94 constrained hours for all the locations reported by the PJM ISO. There are 2000 points in the graph, one for each location. Were it true that there were only a few zones, the graph would show a few clusters of locations where the average prices were the same and the standard deviations were the same. In fact, there is substantial dispersion. After the first 23 days of operation, there were 732 locations within PJM where the prices the points do not overlap and were different by this lower bound test. Presumably as more experience develops and different constraints appear, this number will grow. Recall that in a sufficiently interconnected network, a single thermal limit on a transmission line could create different prices at every location, sometimes very different. This is contrary to the intuition that arises from the misleading analogy to a simple radial transmission connection without any network interactions, where a single constraint results in only two prices. But the network interactions and the many different prices are quite real and no surprise to the system operators.

The standard of no difference in prices may be too strict, and we might be willing to declare two locations as the same if they are close enough. Defining the standard for close enough would be contentious, but it may be moot. If we accept the $1 per MWh threshold above and ask how many separate zones would be necessary to cover all the points in the figure, the answer is 60 zones, so far.[9] This is far more than the few zones predicted, and there is no reason to believe that we are finished adding to the list. Furthermore, as is obvious, the effect of locational pricing for "natural" zones is to produce the same price for all such locations. Hence, aggregating to zones where prices are almost the same still results in many zones and no apparent simplification with any meaning. We might as well do the simpler thing of using the locational prices at each location. Aggregating across locations to a few zones, by contrast, necessarily means combining like with unlike, thereby recreating in microcosm the perverse incentives of "Oz," leading to a breakdown of the non-discriminatory market and administrative restrictions on choice.

The interaction between reliability (with its inescapable physical realities) and economics will limit the acceptable ISO access and pricing rules for allocating scarce transmission capacity. It would be desirable to offer market participants flexibility in their own decisions. A great deal of flexibility in combining a range of bilateral schedules and spot transactions would be possible. However, the more varied and flexible the options for the market participants, the more important it will be to get the prices right, meaning consistent with the marginal impacts on the system. The whole point of the turn to greater reliance on competition is that the market participants will respond to incentives. As we have seen, if prices don't provide the right incentives, consistent with the impacts on the system, the participants will respond in their own interests without concern for the system effects, and the ISO will be driven inexorably to intervene in the market and restrict choice.

PRESCRIPTIONS FOR (I)SOs

There are a few essential services related to coordinating use of the transmission grid where the ISO is both necessary and would have a significant comparative advantage. For example, although it is possible to design an ISO that ignores market preferences, the ISO would have a significant advantage in conducting its short-term coordination activities through an open spot market. In addition to the immediate efficiency improvements, the transparency and ease of entry for small participants would provide a wealth of benefits for promoting the long-run competitiveness of the market. These benefits would include a practical framework for implementing the Commission's CRT proposals, which is embedded in the PJM approach.[10]

The PJM model and similar systems such as for New York, New Zealand, and so on,

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[9] Starting with separate zones for the 10 service territories and sorting on the average and then the standard deviation. To date, Atlantic Electric plus the three service territories outside Pennsylvania and New Jersey have been like one zone, according to this test. The external connection zones would be in addition to the 60 internal zones.

[10] Scott M. Harvey, William W. Hogan, and Susan L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," Center for Business and Government, Harvard University, June 6, 1996, (Revised March 8, 1997).

provide open access with non-discriminatory pricing. The critical short-run matter of congestion pricing and allocation of scarce transmission capacity through locational marginal cost pricing complements other components to deal with the longer-term issues that go beyond system operations. Transmission fixed costs are recovered primarily through system-wide (but not necessarily uniform) network service charges. The ISO administers both a spot market and bilateral schedules, while maintaining reliability under principles of bid-based, economic, security-constrained dispatch. Fixed transmission rights (i.e., transmission congestion contracts) are available for congestion costs between locations, creating the market equivalent of perfectly tradeable physical transmission rights, making the CRT proposal a reality in the only way that is likely to be feasible. Future developments to include multi-settlement systems for forward markets, FTR auctions and coordinated FTR trading.

There is little public policy justification for approving ISO rules that go in the direction of adding further complications while restricting participant choices. Hence, it would be appropriate for the Commission to prescribe rules for the ISO that would support a competitive market in the real world, rather than an idealized world where network complications could be ignored. At a minimum, the Commission should look with great skepticism on proposals that begrudgingly acknowledge that a certain function must be performed by the system operator, but then require that it be performed badly. For example:

> **Balancing Services and Penalties.** The ISO must provide real time balancing to maintain system integrity. Balancing imposes costs, and those relying on the balancing services should pay these costs. However, a strong burden of proof should face those who would charge balancing penalties in excess of costs, or restrict voluntary access to balancing services.
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> **Balancing Constraints.** The ISO must maintain aggregate energy balance in the system, but there is no physical necessity and no public policy interest in requiring particular combinations of transactions to remain balanced. Quite the contrary. Individual balancing requirements both complicate the task for the ISO and provide a device to reinforce market power. This goes against the public interest.
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> **Least-Cost (Re)Dispatch.** The ISO must be able to (re)dispatch plants in order to manage transmission congestion. Rules designed to prevent the ISO from applying the familiar principles of economic dispatch run contrary to the notion of competitive markets and the public interest.
>
> **Voluntary Bidding.** When doing an economic dispatch, it seems logical for the ISO to make the adjustments taking into account the preferences of the market participants as expressed by their voluntary bids. There should be a strong burden of proof for those who argue that it is necessary to restrict the voluntary bids, or discard consideration of some bids.
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> **Transmission Rights and Dispatch.** The ISO must coordinate the use of the

transmission system. And once the actual use of the transmission system is determined, so is the dispatch. The Commission should look with skepticism on any proposal built on the flawed foundation that transmission usage and dispatch can be separated.

Restricting the Grid. The real reliability conditions for the electric grid include an ensemble of contingency conditions and complicated network interactions. Relatively few of these real constraints are simple limits on the actual flow across certain interfaces. The Commission should look skeptically at proposals that require derating the real capacity of the grid in order to make a few flow limits sufficient to guarantee reliability under a simple market model.

Pricing Transparency. Only the ISO would have the information needed to calculate and post locational prices, as in PJM. The computations are easy for a given dispatch, but only the ISO has all the information about the dispatch. Given the striking gap between the previous claims that congestion is insignificant and the observed reality of true locational pricing in the first real implementation in the United States, the Commission should have a strong interest in prescribing that the real locational marginal costs--considering the real network interactions, and not just simplified zonal aggregations--be made available on a regular basis.

Regrettably, these illustrative recommendations are motivated by components found in quite real proposals, a few already approved by the Commission. Some market participants may prefer large transaction costs, trading obscurity, barriers to entry, and the ability to exploit market power. They should oppose these and similar prescriptions. But we should not confuse the public interest in greater competition with an interest in greater profits for ever more competitors. The Commission is the principal body imbued with responsibility for the public interest that can prevent such mistakes.

At the Commission's conference, Richard Haigh observed that embracing these recommendations would be the same thing as supporting an ISO that operates a "residual pool."[11] This is true. For some, the terms invoke a doctrinal reaction beyond reach of any reason, and this is a killer label. However, for those willing to look beyond preemptive dismissal and discuss the ideas on their merits, we should note that the equation runs both ways. Those who reject an ISO which operates such a voluntary, short-run, residual pool to coordinate the spot market are rejecting some or all of these principles, a rejection for which there seems to be little or no justification other than a fear of the open, competitive market that would result. Rejection of these principles amounts to saying that the ISO must perform certain functions, but badly.

[11] Richard Haigh, The National Grid Company, comments on Panel 5, "ISOs and Transmission Pricing," FERC Public Conference Concerning the Commission's Policy on Independent System Operators, April 16, 1998..

CONCLUSION

My recommendations for the major design choices have been clear--an open spot market coordinated through a bid-based economic dispatch, locational marginal cost pricing, bilateral transactions charged at the difference in locational prices, transmission congestion contracts, and so on--as discussed in various papers and previous submissions.[12] However, the main point of my comments is to emphasize the importance of the Commission continuing in the direction it has set out by speaking for the public interest and providing more detail on the appropriate elements of an internally consistent ISO design, with or without a TRANSCO. We cannot escape the heavy lifting of developing further the rules for pricing and access. The Commission should become more prescriptive to reduce confusion and preclude the worst defects, which will be much harder to fix later.

[12] William W. Hogan, "A Wholesale Pool Spot Market Must Be Administered by the Independent System Operator: Avoiding the Separation Fallacy," Electricity Journal, December 1995.