REPORT ON PJM MARKET STRUCTURE AND PRICING RULES

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TABLE OF CONTENTS

I. SUMMARY AND CONCLUSIONS

In response to the Commission's Order No. 888 and the guidance provided in the November 13, 1996 order in the PJM restructuring, the PJM companies are submitting a compliance filing by the Commission's December 31, 1996 deadline ("the Compliance Filing"). While the Compliance Filing is being made by all the PJM Companies, the Supporting Companies and PECO continue to differ on the appropriate pricing methodologies that should be used in response to transmission congestion. The Supporting PJM Companies are proposing rules to implement an efficient, competitive and non-discriminatory market with open access to transmission. By taking advantage of the existing pool structure with its least-cost economic dispatch, retaining operational control of the dispatch by the Office of the Interconnection ("System Operator" or "SO") and adopting efficient pricing of energy and transmission in combination with tradable fixed transmission rights, the Supporting PJM Companies have proposed a market structure and transmission pricing system that provides a major step forward for buyers and sellers of energy and other transmission users in PJM while a refined proposal for an independent System Operator is developed. Equally important, the proposal achieves comparability and efficiency through transmission and energy pricing that is consistent with the actual operation of the grid. As a result, the Supporting PJM Companies have developed a workable proposal that fully addresses the important issues, that resolves them in ways that are fundamentally sound, and that can be implemented in the near term. Among other things, their proposal:

- Provides comparable and non-discriminatory access to the transmission grid. ✓

- Establishes the institutions to support a competitive, non-discriminatory wholesale energy market. ✓

- Maintains reliability.

- Ensures System Operator independence.

- Unbundles generation and transmission.

- Provides efficient, market-based price signals for generation and consumption, and transmission use and investments.

In addition, since the original filing of July 24, 1996, the Supporting PJM Companies have continued to improve their proposal in response to issues raised by stakeholders and as a result of working through the details of how to implement their proposal. This report will highlight those changes where appropriate.

The Supporting PJM Companies propose to restructure the existing "tight" pool currently administered under the PJM Interconnection Agreement (PJMIA) and use the economic dispatch associated with that pool and other market-based concepts to create all of the essential elements to support a competitive wholesale energy market for the entire PJM region. Within this structure, least-cost economic dispatch will be fully preserved, and wholesale market participants will also have the option to schedule bilateral trades of various kinds whether or not they participate in the economic dispatch.

To implement the proposal, the Supporting PJM Companies will turn over to a newly restructured Office of the Interconnection operational control of those transmission and dispatch facilities now operated under the PJMIA. The office will perform the functions of the System Operator (SO) for the PJM control area. The SO will operate the grid as an integrated, free-flowing network throughout the PJM control area, ensuring grid security and reliability under existing reliability standards set by the North American Electric Reliability Council. In addition, the SO will ensure that all eligible market participants receive non-discriminatory access to the entire PJM grid, under pricing and other terms that meet the comparability and open access standards of the Federal Energy Regulatory Commission (FERC).

A key feature of the SO operations will be the ability of any generation supplier to participate in the SO's economic dispatch. Any generation supplier that chooses to participate in the economic dispatch will be allowed to submit voluntary price and quantity offers to the SO on a day-ahead basis, specifying the prices the supplier is willing to accept to operate at output ranges the supplier specifies.[1] Using these voluntary supplier offers, as well as any "demand bids" associated with curtailable or interruptible loads, the SO will determine the least-cost merit order dispatch to serve all loads not met by bilateral transactions. In this way, any supplier will have equal and open access to all loads served at the wholesale level through the SO's dispatch, and the SO's bidding and dispatch rules will apply without discrimination to suppliers regardless of ownership or affiliation.

A second key feature of the Supporting PJM Companies' proposal is the mechanism by which the market will set prices for both energy and transmission. After the SO uses the voluntary price and quantity bids of market participants to determine the least-cost dispatch, the price bids and resulting dispatch will determine market-clearing prices at each location on the grid (i.e., the locational marginal price or LMP). These market-clearing prices will be determined by the marginal cost of serving the last increment of load. These market-clearing prices will be paid to all suppliers who participate in the economic dispatch and will be paid by all loads that are served by that dispatch, while differences in locational prices between the point of withdrawal and the point of injection will be used as the basis for pricing transmission use between those points to account for congestion.

An essential function of the SO will be to ensure that the grid remains in balance at all times and that all transmission constraints are honored to maintain reliability. In the day-ahead bidding process, as well as in real time, the SO will examine all scheduled and actual flows on the grid and will adjust generation and loads subject to the SO's dispatch as needed to maintain frequency, balance loads and resources, and honor all voltage and other reliability constraints. Since the adjustments the SO makes will affect the dispatch and be based on market participants' bids, these adjustments will also affect the resulting market-clearing prices. In particular, dispatch adjustments necessary to relieve transmission congestion and honor reliability constraints will require the SO to dispatch some generation (or loads) out of merit order. The resulting market-clearing prices will differ between locations depending on the degree of congestion between different locations and on the price bids of generators and loads at each location. Since these differences in locational prices reflect the opportunity cost of transmission

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1 These offers must initially be the engineering estimates of costs currently used under the PJMIA to determine the dispatch.

between any two points, the Supporting PJM Companies' proposal will use the difference in locational prices to set the price of transmission usage between points on the grid.

Participation in the SO's economic dispatch will be completely voluntary. Suppliers who do not wish to be dispatched by the SO may instead schedule their trades with the SO. For example, entities that serve loads may schedule their own generation for those loads or they may schedule generation from marketers and other sellers to serve those loads. Under another option, these suppliers may also include with their schedules incremental and decremental bids, indicating the amounts and prices by which they would be willing to curtail or increase their generation, if needed by the SO, in relationship to the market-clearing prices resulting from the SO's economic dispatch.

PJM Load Serving Entities (LSEs) have special obligations flowing from their continuing need to maintain adequate reliable service. The LSEs have the principal responsibility to serve loads in their respective service areas. To help meet these responsibilities, LSEs who are parties to the PJM Interconnection Agreement must meet requirements for installed resources, and each LSE will be required to reserve network transmission to access these resources.

The SO will administer a system of firm transmission reservations. Under the PJM Interconnection Agreement, each LSE will be required to reserve firm transmission sufficient to serve its loads. LSEs will receive "network integration service" for service inside the PJM control area, while all participants may reserve point-to-point service for service out of or through the PJM control area. All transmission users will also be permitted to reserve firm point-to-point service for transactions into and within the PJM control area. The Supporting PJM Companies added this service to their proposal in response to the Commission's guidance and the requests from various stakeholders. Comparable access and pricing rules will apply to both types of firm service.

In conjunction with the firm transmission reservations, firm transmission users will receive a type of financial right called a "fixed transmission right" (FTR), which will entitle the holder to receive compensation for certain congestion-related transmission charges that arise when the grid is congested and differences in locational prices result from the SO's redispatch of generators out of merit order to relieve that congestion. These FTRs will serve the function of price hedges against the uncertainty of congestion-related transmission charges, giving market traders a means to fix in advance the total cost of transmission associated with their trades.

The Supporting PJM Companies' proposal is a conforming tariff, consistent with Order 888.[2] Indeed, with its efficient pricing mechanisms for energy and transmission, the proposal goes beyond Order 888's mandate to provide comparable open access to all transmission users.

The Supporting PJM Companies' tariff is also consistent with the principles and direction FERC laid out in the provisions of the Capacity Reservation Tariff Notice of Proposed Rulemaking (CRT NOPR).[3] The Supporting PJM Companies' proposal will provide tradable fixed transmission rights that are functionally and financially equivalent to, and more flexible than, the capacity reservations described in the CRT NOPR. Both network transmission service and firm point-to-point transmission service as proposed by the Supporting PJM Companies provide the equivalent of flexible point-to-point capacity reservations that the SO would reconfigure in real time to accommodate the actual use of the grid and support the actual dispatch.[4] The proposal's fixed transmission rights, transmission congestion charges and use of locational marginal cost pricing provide a basis for efficient trading at the true opportunity cost of transmission.

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

3 Capacity Reservations Open Access Transmission Tariffs Notice of Proposed Rulemaking 75 FERC ¶61,079 (1996) (hereafter "CRT NOPR").

4 The network transmission service as defined by the Supporting PJM Companies is therefore quite different from network service as that term has generally been used in the past. The PJM network service avoids the limitations of the traditional network service as pointed out by the FERC in the CRT NOPR. According to FERC, the traditional network service has several limitations: 1) there are problems associated with calculating available transmission capacity over time; 2) there are problems associated with having different bases for the pricing of two services in a tariff; 3) having two services is seen as an obstacle to putting all transmission customers on the same basis and hence an obstacle to electric industry innovations and pricing reforms; 4) load-based network service generally cannot be resold, reducing the amount of transmission products and services that can enter the secondary market; 5) the goal of unbundling transmission and generation services may not be able to be fully achieved under load-based network service; 6) transmission planning would be easier under a CRT relative to the load-based network service system; and 7) a CRT would facilitate treating the retail function of a public utility as a separate customer required to nominate and reserve transmission service, enhancing comparability.

The foregoing is just a summary of the main features of the Supporting PJM Companies' proposal. In the remainder of this report, I discuss these elements in greater detail. I focus on the design of the market rules in support of a competitive electricity system for the wholesale market. However, I do not analyze whether any market participants may have market power or consider whether further actions may be required to mitigate market imperfections. In addition, the related issues of governance would have an impact on how the rules might be changed in the future. A full discussion of market power and governance issues goes beyond the present comments.

There are elements of the Supporting PJM Companies' proposal for which various interested parties might have alternative approaches. My comments discuss the tradeoffs associated with these elements. In particular, I examine the implications of an alternative pricing rule supported by PECO and explain why the pricing rule in the Supporting PJM Companies' proposal is superior. On the whole, the Supporting PJM Companies' proposal restructures the PJM interconnection to provide open access and support a competitive wholesale market.

II. OVERVIEW

The Supporting PJM Companies' proposal covers many details, but from the perspective of providing a workable transition to the operation of an open access, competitive market, I would emphasize three components. The proposal:

- Promotes reliability through generating capacity reservation requirements for load-serving entities.

- Allocates fixed transmission cost recovery without rate "pancaking" or distorting the short-term energy market.

- Achieves open, efficient use of the transmission system through locational marginal pricing of energy coordinated through the SO's dispatch, combined with payments of congestion credits for holders of fixed transmission rights.

First, the Compliance Filing promotes reliability in part through continuation of generating and transmission capacity reservation requirements for Load-Serving Entities under the PJM Interconnection Agreement. While some may believe that it is possible to maintain adequate installed generation to preserve current reliability levels purely through market incentives, the Compliance Filing reflects the reasonable judgment that there is not enough experience with competitive electricity markets to reach this conclusion, given the existing market institutions, regulatory policies and system controls. Hence, the Compliance Filing preserves, at least for the present, the traditional reliability mechanism of an installed capacity requirement, without precluding a reconsideration of this issue as the market evolves. At the same time, the Compliance Filing captures some efficiencies through greater diversity and sharing of installed reserves.

Second, the Supporting PJM Companies' proposal provides a mechanism for recovering the sunk costs of the transmission grid through a pricing method that captures the reciprocal nature of transmission service in the PJM control area today, and makes it available to all market participants. The mechanism is a reasonable solution to a difficult problem for which there is no perfect answer. The problem is the need to recover the sunk costs of the transmission grid without distorting decisions regarding the actual use of the grid. The Supporting PJM Companies' proposal addresses this problem by recovering the sunk costs of the transmission grid through monthly charges for transmission determined on a load ratio basis. The PJM control area will be divided into several zones. While the sunk cost recovery mechanism is based on "zonal" transmission charges, it is important to recognize that there is no "pancaking" associated with the transmission charges for these zones.[5] Each LSE that participates in the PJM Interconnection Agreement is required to acquire network transmission service and the accompanying capacity reservations sufficient to serve its loads and they, together with all other network transmission customers will assume the responsibility for paying the fixed costs of the associated transmission.[6] Each network customer within the PJM control area pays only a single zonal charge for all transmission service to deliver power to meet its load, even if the network customer meets its load with power from a generator located several zones away. There are many ways that the sunk costs could be shifted between grid users; however, the reciprocal zonal mechanism largely preserves the current cost allocation without introducing significant inefficiencies into the energy market.

Third, the Supporting PJM Companies propose to charge for the actual use of the transmission grid based on locational marginal prices (LMP). These prices would be determined by the SO based on cost-based price/quantity offers for generation and loads submitted by market participants. The SO would use these offers to determine the least-cost dispatch of flexible generation (and any dispatchable or interruptible loads) to serve loads, consistent with all transmission and reliability constraints, just as system operators today determine a least-cost dispatch based on engineering cost data for generators. Following the real-time dispatch, the SO would use the bid information to calculate the marginal prices for each location on the grid. These LMPs would reflect the cost of serving the last increment of load at each bus within the PJM control area. The Supporting PJM Companies' proposal to charge LMP for spot power and transmission congestion is a key innovation and has a number of strengths:

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5 A distribution charge reflecting lower voltage facilities that are not included in the transmission embedded costs may be separately assessed within its zone by a transmission owner. However, the final access charge will depend on the point of connection, not on the source of the energy.

6 The Supporting PJM Companies' filing of July 24, 1996 included a 10 percent distance-based differential charge for capacity reservations between zones, but it is my understanding that this element of distance-sensitivity has been eliminated from the Compliance Filing, with the issue deferred for later consideration.

1. *The LMP method is consistent with efficient supply and demand for power.* Because the SO would determine LMP based on the least-cost bid-based dispatch of grid resources to meet load,[7] the LMP would be the equilibrium price of power at each bus, equating the marginal cost of supplying an increment of load at each bus (as defined by generator offer prices) with the load's marginal willingness to pay for additional power at that bus. All load that is willing to pay at least the LMP for power is supplied with power at the LMP and, conversely, any dispatchable or interruptible load that is not willing to pay as much as the LMP can reduce its demand and avoid payment. Since all load at the margin pays the LMP, there is no incentive for loads to consume power that a load values at less than its true marginal cost of supply. Similarly, all generation that is willing to sell for the LMP is able to generate, while generation that is unwilling to supply power for this price is not required to produce.

2. *Transmission prices based on differences in LMP provide a comparable basis for pricing transmission use.* To meet the FERC comparability standard, any transmission tariff must charge all parties the same or comparable prices for the same or comparable transmission service. Under the LMP pricing method, the price of transmission use between any two buses within PJM at any point in time is the difference in the LMPs between the sending and receiving buses, irrespective of the identity of the purchaser of transmission or the nature of the transaction. In particular, bilateral and self-scheduled uses of the transmission system pay the same usage and reservation charges as users operating through the SO's economic dispatch.

3. *Using LMP is consistent with bilateral contracts and enables generators to participate in economic dispatch while selling their power through bilateral contracts.* Using LMP, generators entering into bilateral contracts can choose to self-schedule and operate inflexibly in the pool dispatch. However, under LMP, generators will also have the opportunity to participate in the dispatch, either by

7 Both my Report and the Supporting PJM Companies' proposal use "least cost" to mean the same thing as bid-based economic dispatch.

bidding their generation into the pool or by entering into physical bilateral contracts with associated incremental and decremental bids. In this latter case, the generator would simply schedule some portion of its contract with the SO, while also indicating its willingness to increase or decrease some portion of its generation at a designated price. By bidding into the dispatch, a generator gains the ability to fulfill its contractual obligation to its buyer at lower cost than generating the power itself. If a generator bids into the pool at marginal cost and is not dispatched, this means that it can fulfill its obligation to provide power to the buyer with which it has contracted by purchasing power from the pool at an LMP that is less than its own bid. The Supporting PJM Companies' LMP pricing system therefore strengthens and deepens the bilateral market by giving all generators and loads an efficient means to balance deviations from contract quantities in the LMP market (without artificial penalties) as well as to cover their contractual obligations with spot purchases (to the extent that they choose to do so).

4. *Paying generators the LMP encourages new generators to locate where the power they produce will be the most valuable to the load on the grid.* Under LMP, the price that a generator receives for the marginal power that it delivers to the grid is the LMP at the location where the power enters the grid. This encourages new generators to locate where the LMP is high, which means that the cost of meeting load at that location is high. In contrast, pricing systems that pay the same price to all generators, regardless of location, would provide no incentive for investors to locate new generation where it will be the most valuable for serving load.

5. *The LMP method encourages the addition of new transmission to relieve grid congestion efficiently.* LMP provides price signals to guide efficient transmission system expansion. Load that faces high prices due to transmission system constraints has an incentive to invest in transmission system expansion to relieve the congestion, as does generation that is not fully dispatched or receives a lower price due to the same constraints. Pricing systems that are not locational do not

provide load or generation with a direct economic incentive for efficient expansion of the transmission system; instead, they require reliance on more intrusive methods, such as command-and-control regulations.

6. *Charging load the LMP encourages new loads to locate where they can be supplied most cheaply.* Under LMP, all load is charged the marginal cost of supplying power to its location. In the presence of congestion, LMP differs by location, with LMP usually being higher in areas subject to constraints than it is in unconstrained areas. Load therefore has an economic incentive to locate in unconstrained areas where power can be supplied most cheaply. If the price charged to load does not vary by location even though the transmission grid is constrained, buyers have a perverse incentive to locate in areas where it is expensive to supply power since they do not pay the full additional cost that serving them imposes on the system dispatch.

7. *The Supporting PJM Companies' proposal provides price certainty for those who acquire fixed transmission rights.* Grid users with firm transmission service would acquire fixed transmission rights that would hedge congestion costs whether or not actual grid use matched FTR ownership. The holder of an FTR would be entitled to receive a credit to offset congestion charges resulting from any redispatch necessary to relieve congestion or honor reliability constraints. Hence, FTRs function as financial rights, rather than specific performance rights. However, LMP combined with FTRs and congestion credits provide market participants with the equivalent of firm transmission service, thereby enabling loads and generators to hedge the congestion costs associated with their trades. At the same time, nothing in the proposal limits the trading of these FTRs in a secondary market, while the connection with the dispatch through LMP pricing will make trading efficient and easy.

8. *The Supporting PJM Companies' proposal helps mitigate market power.* While LMP alone cannot prevent the exercise of horizontal market power by generators, at the margin LMP will reduce the potential for the exercise of market power both

by facilitating competitive entry and by maximizing competitive pressures on the demand side. Because loads located in constrained regions will pay the same prices that will be paid to similarly located generators, the exercise of market power by generators in a constrained region would provide loads with an incentive to enter into term contracts with competitive entrants, ensuring recovery of sunk costs and thus facilitating entry. Similarly, because loads located in such a constrained region will pay the same prices that will be paid to generators, the exercise of market power by generators will lead to a demand response by loads that will reduce the profitability of exercising market power. Virtually any other pricing proposal -- e.g., zonal averaging for either loads or generation or both -- which by definition does not recognize locational differences, cannot provide these market constraints on the exercise of market power.[8] Moreover, use of LMPs does not preclude or hinder the use of other measures that may be appropriate for mitigating particular instances of market power.

9. *The LMP method is consistent with, and supports, security-constrained economic dispatch by the pool.* Bid-based, security-constrained economic dispatch is necessary to achieve efficiency and reliability. The PJM power pool has employed least-cost security-constrained dispatch for many years and relies on this method to protect reliability and achieve an efficient use of the transmission system and efficient dispatch of generation. The Supporting PJM Companies' proposal preserves this system. Preserving the efficiency of this system is an essential part of the Supporting PJM Companies' proposal. The principal difference in the case of the new market mechanism is to replace the previous split-savings method of payment with market-clearing locational prices. The pricing mechanism does not affect the dispatch principles and leads only to a difference in the settlements process. Locational pricing is essential to make the necessary connection to the competitive electricity market.

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8 State regulators currently have the retail rate-making authority to require their respective PJM Companies to charge consumers the same price over each Company's respective service area. While generators would still be paid at the locational prices, service area averaging for consumers could lessen the ability of locational prices to mitigate market power, although not as seriously as would a proposal to charge all consumers throughout the PJM control area the same prices irrespective of transmission constraints and congestions costs.

10. *Locational Marginal Pricing is Non-Discriminatory.* LMP-based pricing of transactions coordinated by the SO avoids discrimination by placing the SO's operations on a competitive market basis; it thus ensures that SO activities to balance the transmission grid and maintain reliability are efficient, while treating all market participants at a location comparably. In addition, it minimizes reliance on command and control regulation.

In combination, these major elements provide a new market mechanism that will be workable, consistent with the physics of the electric system and (once understood) remarkably simple for market participants. In Appendix B, I illustrate how locational spot prices are calculated, and provide examples showing why the locational prices at various busses on an electric system can be different.

III. GENERAL DESCRIPTION

While the Supporting PJM Companies Open Access Tariff and interchange schedules to the Compliance Filing Interconnection Agreement appropriately contain extended discussions of the rules that will apply in exceptional emergencies, it is useful in understanding the nature of the proposal to focus on how the agreements will operate under normal market and operating conditions, including conditions of congestion. In this section, I first describe the special responsibilities assigned under the PJM Interconnection Agreement to LSEs within the PJM control area to act on behalf of the ultimate loads. I then describe the essential features of the proposal that ensure open, comparable access to support a competitive wholesale electricity market. I then describe how the proposal provides all users with comparable transmission service within that market. I also discuss the allocation and pricing of transmission capacity reservations. Finally, I describe the essential features of the proposal as it relates to the short-term operation of the PJM grid on an open access basis.

A. Load-Serving Entities and Capacity Reservations

The Supporting PJM Companies' proposal provides the mechanisms to support open access for a competitive wholesale electricity market. The focus on the wholesale market emphasizes the responsibilities and opportunities of two important groups: LSEs and all other market participants. Within the PJM control area, LSEs have certain special obligations and are required to meet these obligations in order to achieve certain reliability objectives. Separate from these special responsibilities of LSEs, all market participants, including LSEs, participate in the market with no more than a necessary minimum of coordination through the SO.

The principal responsibility of the LSEs that are parties to the PJM Interconnection Agreement is to act on behalf of the ultimate load to ensure in advance the existence of sufficient generation and transmission resources, and then to act as a purchaser of power in the continuing energy market. All LSEs must identify and reserve sufficient generation capacity resources to provide a margin above their expected peak load. The generation capacity can be provided by any participant in the market, so long as the generation meets applicable reliability criteria, but the LSE is required to make the necessary capacity reservations. In addition, the

LSE must obtain associated transmission capacity reservations from the sources of the reserved generation capacity to the locations of the load. These reservation requirements impose a financial obligation that will be met by the LSE's customers.

Outside PJM, the assumption is that external LSEs will make their own arrangements for generation capacity reservations. Hence, the only requirement imposed by PJM is that these LSEs reserve point-to-point transmission service for power flows from generation resources within the PJM control area to the border of the PJM control area.

As discussed below, the various transmission capacity reservations amount to a form of flexible point-to-point reservations. The transmission reservations within PJM provide transmission capacity reservations for delivery to PJM LSEs and must be made by the LSEs, who also pay the associated embedded costs. All deliveries to loads in the PJM control area would be encompassed by the network service of an LSE that is also a network customer, otherwise those deliveries must be made under specific point-to-point reservations.[9] For delivery outside of PJM, transmission capacity reservations must be obtained from the point of input to the grid to the point of output from PJM. Any market participant delivering to loads outside PJM must make such point-to-point reservations and pay the associated embedded cost rate. The total cost recovery for transmission owners is limited by design to the traditional embedded costs.

B. Wholesale Market

Separate from the required long-term capacity reservations for generation and transmission capacity, the actual day-to-day or hour-to-hour energy market will be completely open for all market participants, not just LSEs, and all participants will be treated in the same way. In the

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9 Initially, the Supporting PJM Companies' proposal ties the LSE's firm reservations and the associated allocation of firm transmission rights to the requirement that each LSE have sufficient generation resources to meet projected loads. However, the Companies recognize that other market participants may also find it useful to acquire point-to-point reservations within the PJM control area and obtain FTRs for any two points, not just those points designated by the LSEs for meeting generation resource requirements. In response to requests from stakeholders, the Supporting PJM Companies have modified their proposal to allow any user to reserve flexible point-to-point firm service within and into the PJM control area. See Part V.C.

hour-to-hour market, transactions and dispatch decisions will be made independent of the decisions in the long-term capacity reservation markets. Any participant can:

- Bid generation and load into the spot market dispatch.

- Schedule bilateral transactions to input, transmit and deliver energy, using its own resources or any other seller's resources to meet loads.

- Arrange any combination of the above.

Under the Supporting PJM Companies' proposal, the SO will dispatch the available resources to meet load at least cost. The SO's dispatch will determine "market-clearing" prices; those are the prices at which supply equals demand at each location and the market is cleared. The market-clearing price for its location will be paid to each generator dispatched in that hour.[10]

The least-cost dispatch and the resulting market-clearing pricing make the Supporting PJM Companies' proposed market consistent with the fundamental economic principle that prices in fully competitive markets should reflect marginal costs to ensure efficiency. When prices reflect marginal costs, the prices buyers pay for consumption and sellers receive for production maximize economic efficiency by balancing the value to buyers of marginal consumption with the marginal cost to sellers of production. The market-clearing prices resulting from the least-cost dispatch will ensure that no seller will want to supply more or less at the market-clearing price and no buyer will want to purchase more or less at the market-clearing price.

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10 Paying all generation the market-clearing price simply recognizes that, in an open bidding system, paying sellers their bids rather than the market-clearing price would encourage them to bid their best estimate of the market-clearing price in order to receive a higher payment. Paying all dispatched sellers the market-clearing price encourages sellers to bid their costs in order to ensure that they are dispatched in the first instance. This helps drive prices to marginal costs, while avoiding the inefficiencies that could result from sellers making bids on erroneous estimates of the market-clearing prices. These marginal-cost-based prices apply to payment for energy and do not include payments for ancillary services or other system costs. See also the discussion in Part IV.D. below. As proposed in the compliance filing, all offers to the market from resources within the PJM Control Area would be limited by a variable cost cap in any event.

In addition, the Supporting PJM Companies' proposal recognizes the inescapable fact that the power supplied to an interconnected grid flows in response to the laws of physics, whatever the contractual arrangements among the users of the grid may be. The demand on a grid can change from instant to instant, and the flows will change in response to those demand changes. In some instances, proposed schedules will lead to flows that would violate grid constraints. When that occurs, not enough lower-cost energy can be transmitted into a constrained area from outside the area to meet the demand in that area, with the result that higher cost generation located in that area must be dispatched. This generation dispatched as a result of a constraint is thus out-of-merit order, and the price to serve load in the constrained area will consequently increase, while the price in unconstrained areas will decrease.

The Supporting PJM Companies' proposal takes account of these realities by determining the market-clearing prices at each location on the grid, including each location where constraints require higher-cost generation to be dispatched to meet loads at that location and locations where lower-cost generation must be curtailed because of the constraints. Consequently, the Supporting PJM Companies' proposal determines not only marginal prices, but *locational* marginal prices. Under the Supporting PJM Companies' proposal, the SO will calculate the marginal cost of supplying electricity at each generation and load bus in the PJM control area every five minutes, with prices determined on an hourly basis by those costs. Thus, the Supporting PJM Companies' proposal extends the efficiency benefits of marginal cost pricing to the demands of electricity markets, by taking into account to the maximum extent practicable the potential for costs to vary by location and over time.

Under the Supporting PJM Companies' proposal, the SO's responsibilities will include accommodating the schedules and achieving the economic outcome for the voluntary bids, subject to all the short-term reliability constraints. The result will give rise to a set of locational prices for generation and load. All purchases and sales through the SO-coordinated spot market will settle at these locational prices. All transmission users will pay the difference in the locational prices between the source and destination. There is no distinction between LSEs and other market participants and no distinction between those who use the spot market and those who use self-scheduled or bilateral transactions. Access to and payment for the services provided by the SO are the same for all participants.

The connection between the capacity reservation system and the market operations comes in the financial settlements process. Everyone pays the same for the actual use of the system. The holders of reservations receive compensation that provides substantial price certainty for those transactions that do not match long-term reservations. In effect, all market participants, at a minimum, have access to the most realistic form of "network service" that can be provided in a real network that has transmission constraints. The long-term capacity reservation system goes beyond this minimal network service to provide additional benefits for market participants while meeting the system's reliability objectives.

C. Network Service

The Supporting PJM Companies' proposal provides a form of "network service" that is available for all users in the market and required for all capacity reservations LSEs who are parties to the PJM Interconnection Agreement. However, the proposal's terminology may cause some confusion because of the differences in alternative definitions of what is possible under network service. The treatment of use of the system when there are transmission constraints is important to any definition of network service. In the absence of transmission congestion, the definition of the service matters little, and there should be no significant problems in providing comparable access. But in the presence of transmission constraints and the associated system congestion, the definition of transmission service matters a great deal, and the rights one would have under what is called network service could be ambiguous. When constraints bind, not everyone can use the network in any way that they would wish; some rules must be applied for restricting usage to conform to the true network limitations.

Network service "without further congestion payments," defined as the ability to use any resource to meet any load, is the usual interpretation of network services under Order 888. Clearly this definition would be inadequate in any constrained system and could not be applied to all participants on a non-discriminatory basis. An alternative definition of "network service" underlying the Supporting PJM Companies' proposal interprets Order 888 to mean that network services should amount to payment of an access charge for the right to use the system, but that actual use of the system should then be charged at locational, opportunity cost prices to deal with transmission constraints whenever the system becomes congested. This alternative definition allows any user to employ alternative resources to meet loads, subject to payment of any congestion costs created by that use and as compensation to other users of the system.

This latter approach is the starting point for the Supporting PJM Companies' proposal for "Network Integration Service." Within the characteristics and capacity of the system, all users of the system will have complete flexibility to use any resources to meet any loads, subject only to a requirement to pay any congestion costs that arise. Hence, all users have full access to the best form of network service that can be supplied to all users on a non-discriminatory basis. In addition, the Supporting PJM Companies' proposal offers firm transmission capacity reservations that go beyond this minimal network service and provide a mechanism for guaranteeing flexible point-to-point service that is hedged against congestion costs.

D. Transmission Capacity Reservations

The proposal provides a mechanism under which LSEs and other grid users can reserve firm transmission capacity to serve their respective loads, with the payments for such capacity being sufficient for the transmission owners to recover the sunk costs of the existing grid. Every LSE will obtain these firm rights in the form of network service. Each LSE will pay the sunk costs of the transmission facilities for the zone in which its load is located. All participants will also be able to reserve firm service within, into, out of, or through the PJM control area and will pay for such service under the firm point-to-point tariff. In addition, each entity paying for firm transmission will obtain so-called Fixed Transmission Rights between the points of delivery and points of receipt designated for the firm transmission service. These FTRs will entitle the holder to receive credits for transmission congestion payments the users would otherwise make when there is congestion on the PJM transmission grid.

LSEs inside PJM and other entities inside or outside of PJM will have the opportunity to acquire these fixed transmission rights as a result of paying for either network service or firm point-to-point service. In the case of network transmission reservations, the points of receipt will be the capacity resources of the LSE acquiring the network transmission service and the points of delivery will be the load buses of the LSE.[11] In the case of point-to-point transmission service, the points of receipt would either be a generation source within PJM or the interconnection(s) with other control areas, while the point(s) of delivery would be the loads within PJM or point(s) of interconnection with an adjacent control area.[12] Network service customers will annually designate a subset of their capacity resources (up to the LSE's peak load) as the origin point for their FTRs.[13]

If all of the requested firm transmission reservations are simultaneously feasible, then all of the requests will be honored. If all of the requested transmission service is not simultaneously feasible, then the initial reservation priorities will be determined by the length of service and the chronological sequence in which the requests are made.[14] Entities that are unable to obtain the requested firm transmission service because of inadequate transmission capability will have the opportunity to finance the transmission facility additions required for the PJM SO to provide the requested firm transmission service.[15]

For reliability purposes, it is important to note that LSEs are required to make the reservations, obtain the FTRs and pay the associated embedded costs. Firm point-to-point transmission customers may also acquire FTRs from their designated point of receipt to their designated point of delivery in the amount of their transmission capacity reservation.[16] In addition, after FTRs are initially allocated, nothing will prevent users from trading the FTRs in a secondary market.[17]

Since decisions to reserve firm transmission service involve assuming fixed payment obligations associated with meeting firm service obligations, such decisions will typically occur

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11 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.2.2 (b) and Section B.2.3.

12 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.2.2 (c).

13 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.2.2 (b).

14 Open Access Tariff, Section 2.2; and Section 13.2.

15 Open Access Tariff, Section 13.5; Section 15.4; and Section 27.

16 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.2.2 (c).

17 Open Access Tariff, Section 23.1. As discussed below, this secondary market trading could also include reconfigurations of FTRs, with the reconfigurations necessarily coordinated through the SO.

well in advance of the actual hour in which service is used. However, it is important to understand that these reservations and associated embedded cost payments do not permanently allocate system capacity and that actual use of the system need not conform to these reservations. Firm transmission users may schedule actual use of the system to correspond exactly with their FTRs, in which case they will receive a credit in proportion to their FTRs for any congestion payments that arise when the SO redispatches generation and loads to relieve constraints. Since in this case the congestion payments and credits will ordinarily offset each other, the net result will be no additional charge to the FTR holder for its firm transmission use. Alternatively, the firm transmission user may choose not to schedule use corresponding to its FTR ownership but instead choose simply to collect any associated congestion payments made by those who do use the grid. In effect, the SO's coordinated scheduling and dispatch, the collection of congestion payments from actual users, and the crediting of such payments back to the FTR holders function as an efficient spot market in firm transmission rights, in which the rights to use the grid are traded for that period at a price equal to the opportunity cost of transmission. Thus, while responsibility for paying the transmission grid's fixed costs are assigned to those who pay for firm use, these assignments do not preclude others from using the grid. Those who reserve firm use and thus incur the obligation for paying fixed costs receive the FTRs and are entitled to any credits arising from congestion. But nothing in the Supporting PJM Companies' proposal would prevent these FTRs from being sold or traded to other potential users in a secondary market before any use is actually scheduled, and even if this explicit FTR trading does not occur, implicit trades at the opportunity cost of transmission would be coordinated through the SO's dispatch during actual use.

E. Short-Term Market

The daily and hourly scheduling process proposed by the Supporting PJM Companies can accommodate a wide variety of transactions, whether purchases and sales of energy coordinated by the SO or self-scheduled or bilateral transactions. Moreover, the proposal provides all transmission users the same options and fully comparable treatment.

1. *Network Integration Service*

Network integration service can be viewed as functionally equivalent to flexible point-to-point transmission service, and provides all LSEs[18] with access to generation throughout the PJM control area. This transmission service can be used to support self-scheduled and other bilateral transactions or purchases through the Mid-Atlantic Market.

<u>SO Coordinated Sales</u>

Any generator within the PJM control area, or with access to the PJM control area, regardless of ownership, can provide the SO with cost-based offers that the SO will use in scheduling the generator. The SO will utilize this information to schedule generation a day ahead and, if the generator is scheduled, to dispatch the generator in real time.[19] The generator would be scheduled to operate if its operating offer placed it within the SO's least-cost merit order (adjusted to meet all reliability constraints) for meeting loads bid into the interchange, given the transmission limits of the PJM grid and taking into account the schedules of all other grid users. The generator would be paid the locational marginal price of energy at its location for its real-time generation and, if scheduled by the SO, would be assured of recovering its start-up, no-load and running costs as bid.[20]

Similarly, the SO will receive day-ahead load forecasts from LSEs within the PJM control area and bids (offers to purchase) from other wholesale buyers with access to PJM.[21] The SO

18 For purposes of this discussion, I use the term "LSE" to mean a load serving entity that is serving load in the PJM control area is a party to the PJM Interconnection Agreement.

19 Interconnection Agreement, Schedule 7.01-1, Section 1.6.1 (e).

20 Thus, if weather conditions changed between the day-ahead schedule and the actual dispatch such that demand was lower than forecast and the energy price alone was insufficient to cover the energy, start-up and no-load bid of a generator scheduled to operate by the SO, the generator would be made whole. Or if a generator were scheduled to start up to relieve congestion and enable a bilateral transaction to be scheduled, but that transaction were canceled in real time making the generator's operation unnecessary, the generator would be made whole.

21 LSEs and other purchasers could also submit decremental bids in the case of interruptible loads or dispatchable loads (if any).

will use these to develop its own forecast to schedule generation to meet forecast loads.[22] LSEs would then purchase energy for these loads at the real-time locational marginal price at each bus. Each LSE and purchaser would also pay a charge covering the cost of ancillary services and control area operations.[23] In addition, until the cost of marginal losses can be reflected in the dispatch and LMP determination, LSEs and other purchasers will also pay allocated losses.[24]

Thus, an LSE with 2000 MW of generation and a load forecast of 1500 MW could simply offer all of its generation into the pool based on its costs and provide the SO with a forecast of its load. The SO would schedule the LSE's generation to operate to the extent each unit's bid costs placed it within the SO's least-cost merit order to meet the loads bid into the SO or to balance the system. The LSE would be paid the LMP for the energy generated by each of its units and would pay the LMP for the energy consumed by its loads. Any difference in locational prices would constitute an implicit payment for congestion costs.

The LSE would have paid for its transmission capacity reservation in advance and therefore would not pay any additional fixed transmission charges. All LSEs, including the current Supporting PJM Companies, would pay transmission congestion charges and would receive transmission congestion credits associated with their FTRs.[25] Thus, if the use of the transmission grid by an LSE in the hour matched its FTR ownership, the transmission congestion

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22 Interconnection Agreement, Schedule 7.01-1, Section 1.6.1 (a).

23 The cost of Operating Reserves for each Operating Day will be allocated and charged to each Market Buyer in proportion to its total load during that Operating Day in the PJM Control Area. The cost of Operating Reserves will be the excess of start-up, no load, and energy costs as bid over payments to each generator for energy. The cost of Operating Reserves measured in this way will be paid to generators scheduled to run by the SO and will be recovered from market buyers. Interconnection Agreement, Schedule 7.01-2, Section 2.2.3.

The cost of regulation will be allocated among market buyers in proportion to each buyer's share of total load in the PJM control area during the hour. Each market buyer will have a Regulation objective based on its pro rata share (based on load) of the Pool's Regulation requirements. Interconnection Agreement, Schedule 7.01-2, Section 2.2.2.

24 The cost of losses will be allocated among LSEs in proportion to their share of hourly load in the PJM Control Area. The allocation proposal is a transitional mechanism until appropriate software is in place to include marginal losses. Interconnection Agreement, Schedule 7.01-2, Section 2.2.5.

25 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.2.

credits and transmission congestion charges would ordinarily offset each other. To the extent that the LSE's use of the transmission grid differed from its FTR ownership, the transmission congestion credits might be more or less than the transmission congestion charges. The redispatch of the LSE's resources would always have the property, however, that the LSE's total cost of meeting load, net of transmission congestion charges and credits, would be less than or equal to the total cost of meeting load solely using the generation associated with the LSE's FTRs.

Self-Scheduled Transactions by an LSE

Under the Supporting PJM Companies' proposal, LSEs can also choose to schedule their own generation resources to meet some or all of their forecast loads, rather than relying on the SO for this scheduling.[26] In this situation, the LSE would provide the SO with schedules, rather than bids, for the generation needed to meet the loads.[27] The LSE would then pay any congestion costs (transmission congestion charges) for transmission from its self-scheduled generation to its loads,[28] as well as any charges for the cost of ancillary services and SO operations and an allowance for losses.[29]

These provisions ensure that trading coordinated by the SO and self-scheduled transactions are priced and treated comparably. For all self-scheduled transactions, the charge for transmission from generation to load would be the difference in the LMPs at each location. Hence, the transmission cost of meeting load would be the same whether the LSE sold the power into the pool at the generator and purchased power from the pool at its loads or the LSE self-scheduled and paid for transmission from generation to load. If it wished, the LSE could also offer regulation and perhaps other ancillary services to the SO by identifying particular units or capacity segments of operating units and placing them under the SO's operational control for

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26 Interconnection Agreement, Schedule 7.01-1, Section 1.6.1 (d).

27 Self-scheduling LSEs would be permitted to provide incremental and decremental bids. Interconnection Agreement, Schedule 7.01-1, Section 1.6.1 (c).

28 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.1.

29 Transmission customers would pay a 2.5 percent or 3 percent charge for losses until the cost of marginal losses is reflected in LMP.

the provision of their ancillary services; the value of these self-provided ancillary services would then be credited against the charges for ancillary service.[30]

Once again, because the LSE would have paid for its firm transmission reservations in advance, it would not pay any additional fixed transmission charges. For actual use, the LSE would pay transmission congestion charges and applicable charges for ancillary services. As when trading through the SO coordinated pool, the LSE would also receive any transmission congestion credits associated with its FTRs; if the use of the transmission grid by the LSE in the hour matched its FTR ownership, the transmission congestion credits and transmission congestion charges would ordinarily offset each other. To the extent that the LSE's use of the transmission grid differed from its FTR ownership, the transmission congestion credits might be more or less than the transmission congestion charges.

Bilateral Sales to LSE

Under the Supporting PJM Companies' proposal, LSEs can also purchase power from electricity marketers or other sellers without paying any additional transmission charges other than transmission congestion charges and losses.[31] Thus, an LSE could contract with an electricity seller for 250 MW of power delivered to its load buses in a particular hour. The LSE would merely inform the SO of the amount and source and that it would be withdrawing the scheduled amount of power from the transmission grid. The seller would not have the responsibility for scheduling transmission from generation to the location of the LSE's load within PJM, but it would be responsible for scheduling deliveries to the PJM border from external resources. These marketer-to-LSE schedules would contain the same information as the schedules of a self-scheduling LSE and could include any incremental and decremental bids for adjustments

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30 Units designated to self-provide ancillary services would be subject to the same rules and operating criteria as units scheduled by the SO to provide ancillary services. Interconnection Agreement, Schedule 7.01-1, Section 1.7.4; Open Access Tariff, Schedule 3, Schedule 5 and Schedule 6.

31 "[T]he Network Customer may use the Transmission Provider's Transmission System to deliver energy to its Network Loads from resources that have not been designated as Network Resources. Such energy shall be transmitted, on an as-available basis, at no additional charge. Deliveries from resources other than Network Resources will have a higher priority than any Non-Firm Point-To-Point Transmission Service under Part II of the Tariff." Open Access Tariff, Section 28.4

against the schedule over a range specified by the marketer through its arrangements with the LSE.

Because the LSE would have paid for network integration transmission service, a marketer or other seller would not need to purchase firm or non-firm transmission to deliver power to the LSE or pay any additional fixed charges. Thus, the only additional transmission charges for marketer-to-LSE transactions would be any relevant transmission congestion charges, any charges for ancillary services and an allowance for losses.[32] The charge for transmission from generation to load would be the difference in LMP prices between source and destination. Hence, the transmission cost of meeting load would be the same if a marketer sold the power into the pool at the generator or if the LSE purchased power from the pool at its loads. Furthermore, the cost of transmission would not depend on whether the transmission service were scheduled by the marketer or the LSE. If it wished, a marketer could also sell ancillary services (e.g., regulation) by identifying particular units or capacity segments of operating units and placing them under the SO's control for the provision of and payment for ancillary services.

If the LSE retained ownership of the FTRs associated with its network transmission service, it would also receive transmission congestion credits associated with its FTRs. It is not necessary, however, for the LSE to retain ownership of the FTRs. For example, as part of the contractual relationship between an LSE and a marketer, the LSE might transfer its FTRs to the marketer for the hours and amounts covered by the contract. In this case, the marketer would receive the transmission congestion credits. If the use of the transmission grid by the marketer in the hour matched the FTRs transferred to it by the LSE, then the transmission congestion credits and transmission congestion charges would ordinarily offset each other. To the extent that the marketer's use of the transmission grid would differ from the FTRs transferred to it, the transmission congestion credits might be more or less than the transmission congestion

32 This allowance for losses would be eliminated when the cost of marginal losses is reflected in the LMP. Interconnection Agreement, Schedule 7.01-2, Section 2.2.5 and Section 2.4.2.

charges.[33] If LSEs acquire these FTRs from the SO in the process of reserving firm transmission, they would incur the obligation to pay the associated fixed costs of the grid. Alternatively, participants could acquire acceptable FTRs on the secondary market and pay the market price.

2. *Point-to-Point Transmission Service*

Firm point-to-point service is functionally no different than firm network service for either self-scheduled or bilateral transactions within PJM except that firm point-to-point service is also available to serve loads located outside of the PJM control area.[34] As with network service, users would pay a fixed charge for reserving service. Like network transmission service, the only charges for actual transmission use paid by loads purchasing firm point-to-point transmission service would be transmission congestion charges, any applicable charges for ancillary services (or payments for ancillary services provided by the user) and an allowance for losses. Like other transmission customers, the charge paid for transmission congestion would be the difference in LMP prices between source and destination. Thus, the charges would be comparable between transmission-only service and the purchase and sale of energy in pool transactions coordinated by the SO. Like LSEs buying network transmission service, loads purchasing firm point-to-point transmission service would receive FTRs that would provide a financial hedge against corresponding congestion charges.

For sales to control areas outside the PJM area, non-firm point-to-point service will in practice differ from firm service in that the transmission customer under the Supporting PJM Companies' proposal will not pay an embedded cost rate for service and the customer will not be allocated FTRs.[35] However, if a secondary market in FTRs develops, non-firm users will be

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33 In addition, LSEs may seek to schedule trades with marketers and other sellers, where the points of injection and withdrawal may not match well with the reservations and FTRs initially obtained by the LSE. LSEs would need a mechanism by which to exchange these for more appropriate FTRs to better hedge their trades. This mechanism could be added as an enhancement in the future and be accommodated in the Supporting PJM Companies' proposal. See Part V.C., below.

34 Open Access Tariff, Part II, Preamble, and Section 13.7.

35 InterConnection Agreement Schedule 7.01-2 Appendix B, Section B.2.2.

able to purchase FTRs from that market. Non-firm customers that do not purchase FTRs will thus pay congestion costs without a right to congestion credits if the non-firm customer elects to continue service in the face of congestion.[36] While the Supporting PJM Companies' proposal permits non-firm transmission customers to buy non-firm transmission on a monthly, weekly, daily or hourly basis,[37] I anticipate that it will, in effect, be an hourly service. Non-firm transmission customers will therefore pay for congestion charges, ancillary services and an allowance for losses. The congestion payments will be equal to the difference in LMP prices between the point of receipt and the point of delivery and will be comparable to the use charges for transmission paid by all other grid users.

For sales to LSEs within the PJM control area, no separate non-firm point-to-point service is required, since all LSEs within the PJM control area are required to contract for firm network service. Hence, all market participants who choose to operate strictly within the PJM control area must ultimately sell to an LSE and, therefore, have automatic access without any further payment of embedded cost charges for transmission. The only transmission usage charges for sales to the market or to an LSE are for congestion, losses and ancillary services.

3. *Conclusion*

Within the PJM control area, all users will have comparable options and receive comparable pricing and scheduling treatment. All users will be able to acquire FTRs, which will entitle them to congestion credits that will hedge the congestion costs between designated locations. They will be able to self-schedule transactions and, at their discretion, provide bids to the SO for generation and load. The SO will redispatch as necessary to accommodate all the schedules and honor the bids. If congestion occurs, every grid user will pay the opportunity cost of transmission as defined by the difference in the locational prices. The transmission owners will receive only payment for their embedded costs. The holders of the FTRs will receive credits of congestion cost payments to compensate them for increased generation costs incurred at the margin because of transmission congestion.

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36 Open Access Tariff, Section 27 and Attachment K, Section 5.e.

37 Open Access Tariff, Section 14.1.

IV. THE SUPPORTING PJM COMPANIES' PROPOSAL IS FUNDAMENTALLY SOUND

The Supporting PJM Companies' proposal is economically sound, supporting a workable efficient wholesale power interchange that is open on a non-discriminatory basis to all eligible traders. In the following sections, I describe how the Supporting PJM Companies' provides the basis for workable and efficient competitive electricity market.

A. Open Access

The Supporting PJM Companies' proposal establishes institutions that will provide all eligible market participants with open, comparable access to the use of the transmission grid and the central coordination services of the SO. Thus, every LSE located within the PJM control area will be able to purchase network transmission services to serve its load within the PJM control area, and any entity will also be able to purchase firm point-to-point transmission service to serve loads located inside or outside of the PJM control area.[38]

Furthermore, it is important to recall that both network transmission service and firm point-to-point transmission service will carry with them rights to transmission congestion credits that will be defined in financial terms, rather than in specific performance terms.[39] The FTRs and associated transmission congestion credits provided by network and firm point-to-point transmission service will be the same.[40] The transmission pricing proposal methodology assures that the SO provides comparable transmission service to all grid users, including service

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38 Open Access Tariff: Part II, Preamble, p. 33, and Section 13; Part III, Preamble; and Section. The ability to reserve firm point-to-point service within the PJM control area has been added.

39 Thus, an LSE with fixed transmission rights from generation A to load B would not necessarily in the hour be served by generation at A. Instead, the PJM SO would dispatch all generation, including the generation located at A, at least cost (as bid). In any particular day or hour, therefore, the least-cost dispatch by the SO may reduce generation at location A in favor of generation located elsewhere inside or outside PJM. Thus, an LSE might have fixed transmission rights from A to B, and have generation located at A under contract, yet the generation located at A might not be scheduled by the SO and the LSE's load at B might actually be met by unaffiliated generation located at C. It is important to recognize that although the Supporting PJM Companies have used the terminology of "Firm Transmission Service" to describe their proposal, the transmission service provided is not firm in a specific performance sense but rather in a financial sense.

40 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.2.2; note, however, that if the SO accumulates excess charges, they will be distributed to those with network service but not to those with point-to-point service.

when out-of-merit dispatch of generation resources is required to accommodate transmission constraints. As discussed below, it is accurate and helpful to think of both network transmission service and firm point-to-point transmission service as flexible point-to-point capacity reservations that are reconfigured in the hour based on the bids of the customers participating in the SO dispatch. During normal operating conditions, the Supporting PJM Companies' proposal will therefore treat all transmission customers comparably in the provision and pricing of transmission services, while the SO's least-cost dispatch will, in effect, provide an efficient market for trading and reconfiguring transmission reservations in real time.[41] And, since everyone at a particular location, at a particular time, will face the same short-term economics and pay the same price at the margin without distinction according to identity or affiliation, the principle of non-discrimination is embodied in the pricing system.

B. Role of the Office of the Interconnection

A core feature of the Supporting PJM Companies' proposal is the recognition of the need to preserve central coordination of the final dispatch of generation and load in order to ensure efficient and reliable use of the PJM transmission grid. Because of network interactions, this central coordination of short-term operations using a common transmission grid is unavoidable. In adapting existing PJM institutions to an open access, competitive wholesale market, the Supporting PJM Companies have organized this central coordination role around a short-term market operated as a bid-based economic dispatch. Through this mechanism, the SO can simultaneously protect the reliability of the system; internalize the complex externalities caused by loop flow and network interactions; and provide transparent open access to the transmission grid to buyers, sellers and transmission customers.

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41 It is important to recognize that although the Supporting PJM Companies have drafted their open access tariff to follow the language of the Order 888 pro forma tariff wherever possible, that language may contribute to some confusion when applied to the proposed market mechanism. In particular, while the Supporting PJM Companies have retained language regarding priorities among customers in Sections 13.6, 13.7, 14.2, 14.5 and 14.7 of the Open Access Tariff, the primary and normal allocation mechanism will be market-based and determined by the bids of flexible generation and load and by the incremental and decremental bids of flexible transmission customers. Curtailment based on non-market priorities will be resorted to only if the transmission constraint "cannot be relieved through the implementation of least price redispatch procedures," Open Access Tariff, Section 33.4.

These changes in the organization of the PJM interconnection are reflected in the SO's role of overseer of the future operations of the PJM control area. In designing this new structure, the Supporting PJM Companies have respected four important principles. The SO:

- Has responsibility for central coordination of the scheduling and dispatch of generation and load to accommodate bilateral schedules, meet load and achieve economic dispatch while maintaining short-term reliability.

- Provides open, non-discriminatory access to the PJM grid and the SO's coordination services. The SO has access to all bids of willing buyers and sellers, and all buyers, sellers and grid users have the opportunity to enter into transactions using the PJM transmission grid or through a spot market coordinated by the SO.

- Relies on markets rather than administrative edicts wherever possible, without sacrificing efficiency or reliability.

- Has no commercial interest in the transactions it coordinates.

1. *Central Coordination*

The Supporting PJM Companies have given the SO the responsibility for maintaining reliability and for coordinating the scheduling and final dispatch of generation and load at least cost.[42] This is the appropriate objective for the SO and the only way for the system coordinator to achieve a result consistent with a competitive market.[43] Economic dispatch by the SO based on bids provided by generators, loads and transmission customers[44] provides an efficient and

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42 Interconnection Agreement, Schedule 7.01-1, Sections 1.4 through 1.7.

43 This is also consistent with principles 4, 5, 6 and 8 set forth by the FERC for the ISOs in Order 888; see p. 31,731-732.

44 Entities using transmission for bilateral transactions would have the opportunity to provide the SO with incremental and decremental bids that would describe the customers' willingness to adjust injections and withdrawals in response to locational marginal prices. Interconnection Agreement, Schedule 7.01-1, Section 1.6.1 (c).

comparable basis for balancing the system in real time. Bid-based economic dispatch by the SO corresponds to the least-cost procurement of balancing services by the SO and to the competitive market equilibrium.

The Office of the Interconnection will have primary responsibility for ensuring short-term reliability, as it does today. Furthermore, dispatch algorithms and protocols similar to those that have been used by PJM system operators in the past will continue to be used by the PJM SO in the competitive market, thus ensuring the continued safe, reliable operation and efficient use of resources.

The SO's central coordination is needed to support a competitive market and is unavoidable because of the role of loop flow and its effects within the system. When someone transmits power in an electric grid with loops, parallel flows arise that can significantly affect the systems and dispatch of third parties not involved in the transaction. Economists call this an "externality," that is, a cost imposed on others that, unless appropriate measures are taken, will not be paid for by the party imposing the cost. In the absence of a central coordinator, loop flow effects would result in shifts in cost responsibility, because loop flow can create externally imposed costs that are not paid for by the entity causing the flow. With existing networks and technology, there is no way to avoid this loop flow effect. The free-flowing PJM electric grid is an asset that for reliability reasons should be preserved, not abandoned, in the transition to a more competitive electricity market.

Theoretically, property rights in the transmission grid, in the usual sense, would allow the owners of these property rights to control the flow of power and reduce the need for central coordination. If we could develop a workable system of property rights, we could internalize the externalities and achieve an efficient outcome through a decentralized competitive market. In the presence of loop flow and a free-flowing grid, however, there is no workable system of decentralized property rights in transmission alone that is capable of maintaining current reliability levels or achieving a competitive market equilibrium. Some degree of central coordination of the use of the rights is required.

In the Supporting PJM Companies proposal, the SO's central coordination will deal efficiently with the externalities caused by loopflow. Using locational prices derived from market participants' voluntary price offers the SO will coordinate an efficient allocation of the costs of transaction to those responsible for those costs. In addition, SO will administer a system of transmission rights (FTRs) that will efficiently allocate scarce transmission and appropriately compensate FTR holders.

The FTRs administered by the SO are not physical property rights in the usual sense. They do, however, provide a critical feature of property rights in protecting long-term contracts for transmission costs. FTRs accomplish this by giving the FTR holders assurance of a fixed price for transmission, or alternatively, giving them the ability to trade that assurance to others who may value the right more. Moreover, the FTRs do not provide for decentralized control of grid operations. The Supporting PJM Companies' proposal relies on the SO to provide central coordination in both the real-time dispatch and the day-ahead scheduling process. Thus, all grid users must coordinate their actual use of the grid through the SO so that the SO has the information and resources needed to balance the system to maintain reliability in real time.

The Supporting PJM Companies' proposal also permits grid users to schedule their transactions with the SO a day in advance of the actual dispatch.[45] Because some generators have significant start-up time, day-ahead scheduling will give the SO more lower-cost alternatives to relieve congestion if that congestion is identified a day in advance of the actual dispatch than if the SO first identifies the congestion closer to real time. While transmission customers with bilateral contracts are not required to schedule their transactions a day in advance under the Supporting PJM Companies' proposal,[46] they have the opportunity to do so and will likely find that congestion costs are reduced if they do so, because with the advance scheduling the SO will have more lower-cost alternatives available to accommodate their transactions.

45 Interconnection Agreement, Schedule 7.01-1, Section 1.6.1.

46 Market participants may schedule non-firm bilaterals or self-schedule resources (not previously scheduled) on an hour-ahead basis. This implies that day-ahead scheduling is not required. Interconnection Agreement, Schedule 7.01-1, Section 1.6.9.

2. *Open Access*

The Supporting PJM Companies' proposal provides open non-discriminatory access to the transmission grid and to the services under the SO's control.[47] The Supporting PJM Companies' proposal avoids artificial separation of the integrated roles of the SO or artificial restrictions on the bids that are made available to the SO by generators, loads or transmission customers. In particular, the SO will be able to identify transmission constraints on the system and take operational actions to relieve those constraints, relying on the bid-based economic preferences of the grid users to redispatch generation and loads and set the price for congestion-related charges.[48] Thus, the Supporting PJM Companies' proposal imposes no artificial restrictions on the actions of the SO that would preclude the SO from providing transmission services to any customers willing to pay the opportunity cost of those transmission services. Nor does the proposal preclude the SO from acquiring the generation services required to provide those transmission services.

The Supporting PJM Companies' proposal assures that all wholesale market participants have the opportunity to use the PJM transmission grid to support bilateral transactions and that all buyers and sellers have comparable access to the spot markets coordinated by the SO.[49] The proposal places no restrictions on bilateral transactions that would preclude willing parties from doing business on that basis if they so choose. All generation resources in PJM, or with access to PJM, will be able to offer energy to the PJM interchange energy market and the SO will be able to make use of all of these bids both in scheduling transactions and resources a day ahead and in balancing the system in real time.[50]

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47 Owners Agreement, Section 6.1.

48 Interconnection Agreement, Schedule 7.01-1, Section 1.6.8; Open Access Tariff, Section 33.2 and 33.3.

49 Interconnection Agreement, Schedule 7.01-1, Section 1.6.

50 Interconnection Agreement, Schedule 7.01-1, Sections 1.6, 1.6.1, 1.6.2, 1.6.5, 1.6.8 and 1.6.9. The Supporting PJM Companies' proposal imposes limits on hour-ahead adjustments in bid prices; see the Interconnection Agreement, Schedule 7.01-1, Section 1.6.9 (a). It is my understanding that these limitations reflect limitations of the existing software. If grid users wish, it may be possible to relax these limitations when the new EMS system is available in 1998.

Similarly, all entities located either inside or outside of the PJM control area will be able to purchase transmission services and energy through the SO to support transactions in the PJM interchange energy market. The SO will take account of these loads and requests for transmission services in committing resources both a day ahead and in balancing the system in real time.[51]

Finally, the role of the SO as structured by the Supporting PJM Companies' includes all of the market elements affecting wholesale transmission access. It thus ensures that there are no agreements affecting wholesale access to the transmission grid that are outside FERC jurisdiction.[52]

3. *Reliance on Market Mechanisms*

The Supporting PJM Companies' proposal is designed so that the SO will rely on market mechanisms to the maximum extent feasible both in maintaining reliability and in coordinating open access use of the transmission grid.[53] Thus, the Supporting PJM Companies' proposal employs locational spot pricing, based on market participant bids (although limited to variable costs in the interim), for the SO to obtain generation resources needed to serve load, relieve transmission congestion and allocate use of the transmission grid based on the bids of grid users.[54] Similarly, the Supporting PJM Companies' proposal provides loads with the ability to reduce costs by becoming dispatchable or interruptible at a given price, ensuring that the cost of power is consistent with its value to consumers.[55] In addition, I understand that the proposal will allow market participants to offer some ancillary services to the SO and receive appropriate compensation for those services.

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51 Interconnection Agreement, Schedule 7.01-1, Sections 1.6, 1.6.1, 1.6.3, 1.6.6, 1.6.7, 1.6.8 and 1.6.9.

52 These elements of the Supporting PJM Companies' proposal are consistent with FERC's principles 3 and 6 for ISOs, see Order 888, p. 31,731.

53 This is consistent with principles 3 and 7 set forth by the FERC in Order 888; see p. 31,731.

54 Interconnection Agreement, Schedule 7.01-1, Appendix A.

55 External loads can submit a dispatch rate above which they would not take energy from the market. Interconnection Agreement, Schedule 7.01-1, Section 1.6.1(b). Internal loads can either be dispatchable (Interconnection Agreement, Schedule 7.01-1, Section 1.6.1 (a)) or interruptible (Open Access Tariff, Section 29.2 (iv)).

It is my understanding that, except for payments to cover start-up and minimum load costs, there is no explicit payment for the amount of spinning reserve provided by each generating unit because PJM's operators are confident that, while additional units may be committed in order to provide additional spinning reserve,[56] it will rarely if ever be efficient to dispatch a unit's energy production out-of-merit in order to provide spinning reserve. In this event, there would be no opportunity cost for spinning reserve. To the extent that this assumption is violated, there may be a need to provide compensation for spinning reserve.

This reliance on market mechanisms promotes economic efficiency and also makes the SO's actions more auditable, because there is an objective bid-based criterion and market mechanism governing the SO's actions. This reliance on market mechanisms is also desirable because it provides comparability in the treatment of grid users. Requiring the SO to rely on market-based mechanisms and then allowing all grid users to participate in these markets goes a long way toward ensuring comparable access to the transmission grid.

4. *No Commercial Interests*

The Supporting PJM Companies' proposal provides for an SO that has no commercial interest in the market. The SO coordinates the (very) short-run market on behalf of the commercial interests selling into the market and the grid users that rely upon the SO to serve load and maintain reliability.[57] The proposal leaves all other market activities, including setting the terms of contracts, to the individual market participants.

C. Recovery of the Sunk Costs of the Transmission Grid

The Supporting PJM Companies propose to recover the sunk costs of the transmission grid through monthly demand charges for network transmission service within PJM and fixed charges

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56 Units would be committed based on least overall cost and would, if committed by the SO, be assured that they would recover their costs as bid, including their start-up, no-load and running costs. See Interconnection Agreement, Schedule 7.01-2, Section 2.2.3.

57 Interconnection Agreement, Section 9.3; and Schedule 7.01-1, Sections 1.6.8, 1.6.9 and 1.7.

for firm point-to-point service.[58] The need for these access charges arises because congestion revenues collected by the SO from the spot market will not be sufficient to recover the embedded cost of the transmission grid. Due to economies of scale and diminishing returns, as well as differences between forecast and actual outcomes in transmission grid planning, the congestion-related revenues from the short-term opportunity costs of transmission will typically be only a fraction of the embedded cost of the grid. If the cost of the grid is to be recovered by the transmission owners, there must be a set of charges that apply to grid users and add up to the embedded costs of the transmission grid.

Given the need to recover these embedded costs, the issue from the standpoint of public policy and economic efficiency is how to collect these transmission charges in a way that minimizes the distortions in the electricity market and simplifies the transition to competition. These considerations suggest a set of access charges that are to the maximum extent possible independent of variable energy use and independent of the source of the energy without creating cost-shifting among the various market entities.[59] The implication of these principles is that access charges should be directed toward fixed charges or inelastic demands; they should apply to load without variation according to the source of generation; and they should be directed to recovering the separate transmission revenue requirements of the individual companies. There will of necessity be practical tradeoffs in implementing these guiding principles and it should be recognized that even in idealized markets there is no perfect solution to this problem.

The Supporting PJM Companies' proposal for the recovery of sunk transmission costs contains a reasonable balancing of these considerations. The transmission-owning utility as such receives its embedded costs and no more. The payment for both the existing grid and new grid investments will be based on cost according to traditional regulation, and those paying the regulated fixed charges for transmission receive the benefits of the grid they pay for. The SO keeps nothing, the owning utility shareholders receive an opportunity to recover investment at

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58 Open Access Tariff, Section 25.

59 The third point includes avoiding creating incentives for grid users to restructure themselves in order to avoid paying the sunk costs of the transmission grid. Furthermore, this avoidance of cost shifting removes barriers for LSEs to join with PJM and develop a regional SO by eliminating the possibility that joining would inherently require paying for the embedded cost of other transmission owners' investments.

a regulated rate of return, the FTR holder receives compensation for congestion charges resulting from out-of-merit dispatch and the transmission user pays the true opportunity cost. This proposal will provide LSEs with network service within the PJM control area with the proper incentives, as the single non-pancaked rate for network transmission service will be based on their peak load but will not be related to the amount of energy consumed in any hour or to the origin of the energy consumed in any hour.[60] Furthermore, because the same charge for network transmission service would be paid by all LSEs within a common zone, similarly located customers will pay the same charge; thus the overall transmission pricing system should avoid cost shifting among grid users.[61]

The charge for firm transmission service to loads outside PJM (firm point-to-point service either from generation within PJM or generation moving energy through PJM) will also be a single non-pancaked rate. This rate will be related neither to the amount of energy transmitted in any hour nor to the origin of the energy transmitted. Thus the rate will provide reasonably efficient incentives.[62] Significantly, there will be no embedded cost charge for non-firm point-to-point transmission service. Customers relying on that service will face true opportunity cost-pricing through congestion charges and losses.

The combination of bid-based economic dispatch, locational marginal cost pricing, non-pancaked transmission access charges and fixed transmission rights linked to transmission congestion credits provides a system that meets the Commission's test for a conforming transmission access and pricing proposal. The revenues collected by the transmission facility owners are no greater than the embedded costs of the system. The SO collects opportunity costs created by transmission congestion from those contributing to the congestion and distributes the congestion revenues to the holders of fixed transmission rights, compensating them for their opportunity costs associated with redispatch and forgoing their own use of the transmission grid.

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60 In the original proposal, there was a 10 percent differential transmission access charge based on the source of reserve capacity reservations. However, it is my understanding that the Supporting PJM Companies have agreed to defer this proposal for now.

61 It should be kept in mind that assessment of cost shifting must take into account changes in payments for energy and transmission congestion credits as well as any changes in payments for transmission service.

62 Open Access Tariff, Schedule 7.01.

In the case of system expansion, either the beneficiaries of the expansion will pay the incremental costs or the transmission owners will pay the incremental costs and recovery will be spread across all users of the system.[63] In any event, the transmission facility owners will never receive more than their embedded cost rate, and opportunity costs will be redistributed among the users of the system and the holders of fixed transmission rights.

The proposal does not result in "and" pricing by the transmission owners. The transmission owners collect their traditional revenue requirement and no more. Payments for congestion costs associated with transmission constraints flow to the holders of FTRs, not to the owners of the transmission system. Transmission pricing is non-discriminatory and fully comparable between transmission owners and other users. The usage prices reflect opportunity costs and support economic efficiency. The system is fair, and it is practical. Hence the package is consistent with the Commission's pricing policy statement and is a conforming proposal.

D. Efficient Pricing of Spot Energy and Transmission

The necessary price incentives for a competitive power market include marginal opportunity cost pricing of energy and transmission. Associated with a bid-based economic dispatch is a set of locational marginal cost prices that are defined by both the costs of the market participants (as expressed in their bids) and the physics governing interactions on the transmission grid. In an open access transmission grid governed by a centrally coordinated economic dispatch, the marginal cost of energy at each location includes the cost of generation, the cost of marginal losses and any congestion costs arising from a need to dispatch the system to respect reliability limits and transmission constraints. Furthermore, within such a dispatch system, the short-run opportunity cost of transmission between locations is equal to the difference in their locational marginal prices.

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63 Open Access Tariff, Section 32.4.

Recognizing these fundamental relationships, the Supporting PJM Companies' proposal will employ locational marginal pricing,[64] based on the centrally coordinated economic dispatch by the SO, to price spot energy and transmission within the PJM control area. All generators selling power in spot transactions coordinated by the PJM SO will be paid the locational marginal cost price for the power delivered into the grid.[65] All entities buying power in spot transactions coordinated by the PJM SO will pay the locational marginal cost price for power withdrawn from the grid.[66]

I emphasize that the pricing system proposed by the Supporting PJM Companies will pay the same market price to all generators dispatched by the SO who inject power into the grid at the same location. Thus, the SO does not attempt to price discriminate among generators by paying each generator its bid rather than the market price. Such a discriminatory pricing system may appear attractive for loads in the short run, but only if one assumes that generators would indefinitely be required to bid their costs in a system in which they are paid their bid prices. In reality, however, not only is such a discriminatory system undesirable from a public policy perspective,[67] but the benefit to loads would be illusory as in a competitive market such a system would motivate generators to bid their estimate of the market price, rather than their costs. Pricing systems that attempt to price discriminate among generators based on their discretionary bids would not actually benefit loads either in the short run or the long run, but

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64 Initially, PJM will use average losses (2.5 percent for off-peak; 3.0 percent for peak periods) and not take account of incremental losses in either the dispatch or the calculation of locational marginal prices, due to software and hardware limitations. The Supporting PJM Companies anticipate transitioning to a system that takes account of marginal losses both in the dispatch and in the calculation of locational marginal prices when the necessary systems are available. Interconnection Agreement, Schedule 7.01-2, Sections 2.2.5 and 2.4.2.

65 Interconnection Agreement, Schedule 7.01-2, Section 2.3.1.

66 Interconnection Agreement, Schedule 7.01-2, Section 2.2.1. It should be noted that although the SO will calculate an average LMP for each LSE, because the average price is weighted by the load at each bus, the incremental cost of each MWh of power delivered to each LSE is the locational marginal cost.

67 A pricing system based on monopsonistic price discrimination would be undesirable from a public policy standpoint for at least two reasons. First, generators and customers are both market participants and it would not be appropriate for the FERC to establish regulatory mechanisms that transfer wealth from one market participant to another through the exercise of market power, particularly at the cost of market efficiency. Second, any benefit to loads from the establishment of such regulatory mechanisms would be purely short run and loads would in the long run bear the cost of the resulting inefficiency.

instead would raise market costs and favor generators that have superior information regarding likely market price levels.

Similarly, under the Supporting PJM Companies' proposal, all grid users will pay for spot transmission based on locational spot prices. Thus, the price of spot transmission between any two locations will be the difference in locational spot energy prices. These transmission prices will, at the margin, be paid by all grid users,[68] including transmission customers, LSEs or others buying and selling power through the grid, and self-scheduling LSEs.[69]

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[68] In the case of counterflows, congestion costs will be negative and a payment would be made to the grid user.

[69] Interconnection Agreement, Schedule 7.01-2, Sections 2.2.4 and 2.4.1, and Schedule 7.01-2, Appendix B, Sections B.1.3, B.1.4 and B.1.5. The description in Appendix B has perhaps been misunderstood by some parties because of the way it is set forth. The agreement states that congestion costs for network service will be calculated as the difference in locational prices between each generator and the LSE's average load. Mathematically, this is equivalent to the difference in locational prices between each generator and the load served by that generator (summed over each MW of generation) but the expression in the agreement is helpful as it avoids the need to verbally describe which MWh of load is paired with which MWh of generation in calculating congestion.

Thus, the market agreement provides that the congestion charges paid by each LSE utilizing network transmission service to meet its load from its generation resources would be:

$$[1] \quad \sum_{j} \left(\frac{\sum P_i d_i}{\sum d_i} - P_j \right) g_l$$

where P_i, P_j are the locational prices at load i and at generator j, respectively. The demand at Bus j is d_j. The generation at bus l is g_ℓ. Thus, congestion is paid on the difference between the weighted average load price and the generator's locational price.

This can be rewritten as:

$$[2] \quad \sum_{l} g_l \frac{\sum_{i} P_i d_i}{\sum d_i} - \sum_{l} P_j g_l$$

since imbalances would be settled at LMP prices,

$$\sum_{l} g_l = \sum_{l} d_l$$

[2] reduces to

$$[3] \quad \sum_{i} P_i d_i - \sum_{j} P_j g_l$$

This expression could, in turn, be rewritten as:

$$[4] \quad \sum_{m=1}^{L} (P_{\ell m} - P_{gm})$$

where the m, ℓ, and g notation maps each 1 MW of load to a unique generation source. The formulation in the filing (equation [1]) therefore corresponds to equation [4] but is more general in that it does not require relating each load to a generator.

The locational spot prices will be determined by the SO's real-time, bid-based dispatch of loads and generation across the transmission grid.[70] The principles underlying locational spot pricing have been widely discussed and are well defined.[71] Since prices are calculated ex post from the actual dispatch, there is no computational difficulty in determining the price at every location in the real system. The real-time dispatch, along with the participant bids and the characteristics of the transmission grid, provide the information needed to determine a set of consistent prices that incorporate all the effects of loop flow, network interactions and the preferences of all the participants as expressed in their voluntary bids.

In this respect, it is essential to distinguish between the complexity of maintaining reliability (which the Supporting PJM Companies achieve through security-constrained economic dispatch and which would be a requirement under any market mechanism) and the complexity of the price-determination mechanism. Coordinating the operation of hundreds of generators, dozens or hundreds of bilateral transmission transactions and loads at hundreds of buses to maintain reliability while accommodating the commercial transactions of grid users is unavoidably complex. This coordination to maintain reliability, however, is currently provided within PJM and has been working for many years. Security-constrained dispatch techniques are also widely used by other utilities and power pools. The recognized ability of PJM and other power pools to provide this coordination underlies FERC policy. Since this coordination role is necessary,

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70 Data describing the real-time dispatch will determine the locational marginal prices. At each substation bus in the PJM control area bulk power transmission system where electric power is delivered by sellers and/or receipt is taken by buyers, deliveries and receipts will be measured and the measurement data will be transmitted to SO computers. Actual power flows on the bulk power transmission facilities will be similarly measured or, in some cases, calculated. At 5-minute intervals, a state estimator program similar to those currently used by system operators to operate the bulk power system will provide the status, via a solved power flow, of the bulk power system to an LMP program. The LMP program will also have as an input the solved power flow, relevant bid data for all resources making deliveries to the SO operated spot power market, as well as any bids of loads, and identification of binding transmission constraints. This is all that will be needed to calculate the marginal cost of electricity at each substation in the SO bulk power transmission facilities grid for each of the 5-minute intervals. Interconnection Agreement, Schedule 7.01-1, Appendix A.

71 F. C. Schweppe, M. C. Caramanis, R. D. Tabors and R. E. Bohn, *Spot Pricing of Electricity*, Kluwer Academic Publishers, Norwell, MA, 1988; W. W. Hogan, "Contract Networks for Electric Power Transmission," *Journal of Regulatory Economics*, Vol. 4, No. 2, September 1992, pp. 211-242; W. W. Hogan, "Contract Networks for Electric Power Transmission: Technical Reference," Harvard University, December 1991; S. M. Harvey, W. W. Hogan and S. L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," August 7, 1996 (revised October 14 and filed with FERC on October 21, 1996, by W. W. Hogan as part of comments on the CRT NOPR).

the issue is not whether it is complex, but whether it would for some reason become more complicated under the Supporting PJM Companies' proposal and whether the inherent complexity should be managed with market or non-market processes.

Having the SO operate essentially the same dispatch algorithms now used for the PJM control area would not complicate the problem. And using those algorithms to compute market-clearing prices based on bids and offers would greatly reduce the gaming opportunities and inefficiencies inherent in the current system of split-savings payments based on engineering estimates of costs. If competition is to be reasonably efficient and effective while maintaining reliability, the essential dispatch process must be put on a non-discriminatory market basis, and that is what the current proposal accomplishes through its open, voluntary bid-based dispatch and scheduling mechanisms.

It is particularly important in this regard that the Supporting PJM Companies' LMP proposal avoids creating any artificial limits on the resources available to the SO for balancing the system, either in real time or a day ahead. Such limits would arise if the integrated SO functions of determining the least-cost dispatch, managing congestion and maintaining system reliability were artificially separated, requiring additional coordination to ensure that all participant bids submitted for use in the day-ahead scheduling and dispatch would also be available to assist the SO in managing congestion and maintaining reliability. Furthermore, the use of LMP provides generators and loads with market-based incentives to make flexible resources available (i.e., to bid these resources) to the SO for use in its coordination role. Because all the resources needed by the SO to balance the grid are paid the locational market price under the Supporting PJM Companies' proposal, there is no artificial incentive for balancing resources to bypass the SO and enter into inflexible contracts or to bid inflexibly in order to be paid the market price.

After the system has been dispatched on an economic, security-constrained basis, the calculation of locational prices requires solution of a relatively simple set of relationships. Given the dispatch, network parameters, the identity of the binding constraints and access to the bids, any authorized auditor could easily verify the calculation of locational prices.[72]

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72 Arranging the dispatch may be complex, but once it is determined, the determination of a set of consistent prices is not.

The Supporting PJM Companies' energy and transmission pricing system is thus workable, efficient and consistent with FERC policy. In particular, the proposed pricing mechanism:

- Ensures that energy and transmission services are priced consistently and are available at cost-based offer prices to all traders, including small undiversified ones.
- Provides all energy sellers and consumers with efficient marginal incentives.
- Efficiently allocates use of the transmission grid.
- Avoids reliance on complicated "but for" price calculations that would require a determination of alternative dispatches, limits shifting of costs into uplift[73] and reduces the potential for gaming.

1. *Consistent Pricing of Energy and Transmission*

The Supporting PJM Companies' locational spot pricing mechanism prices energy and transmission consistently because it recognizes that transmission is economically equivalent to selling power at the point of receipt and buying it at the point of delivery.[74] Locational spot pricing of transmission also allows all traders, including small undiversified traders, to buy energy and transmission services at bid-based market prices. The resulting efficiency of the Supporting PJM Companies' locational pricing therefore avoids inefficient incentives or selective biases favoring one transaction over another while it minimizes opportunities to game the use of the transmission grid or energy market.

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73 Uplift is a charge imposed on all consumers across the board rather than directly on those whose transactions contribute to congestion.

74 Interconnection Agreement, Schedule 7.01-2, Appendix B, Sections B.1.3, B.1.4 and B.1.5.

2. *Efficient Marginal Incentives*

It is a fundamental economic principle that prices equal to short-run marginal cost provide buyers and sellers with efficient production and consumption incentives. If buyers pay the cost incurred by sellers who increase supply to meet the buyers' demand, consumption decisions will be made efficiently. For electricity, efficient pricing must take account of the variation in the delivered cost of electricity by location (spatially) and over time (intertemporally).

The Supporting PJM Companies' proposal provides buyers and sellers with efficient marginal incentives in the short-term market by ensuring that all transmission and energy transactions coordinated by the SO are priced equal to marginal cost. The locational prices not only produce efficient short-run decisions for electricity consumption and transmission use, they also provide a market method to signal efficient long-run grid expansion as well as a method to compensate firm transmission customers for their true opportunity cost when transmission is used by a third party with a higher-valued use.

In addition, locational marginal cost pricing provides both prospective generators and loads with efficient locational incentives. Thus, LMP will provide entities considering the construction of new generating capacity within PJM with market-driven incentives to take account of transmission congestion in their location decisions. Importantly, firms considering the construction of new generating capacity at a location from which power exports are transmission-limited will have to take into account the financial impact of congestion, since it will affect the locational price they are paid for spot power or the locational price of transmission congestion paid for in connection with bilateral transactions. It will not be necessary for a regulatory agency, however, to deny firms the opportunity to build new generating capacity in a perceived constrained location nor will it be necessary for new generators to pay for transmission upgrades that may not be cost-effective for them or for the system as a whole. Instead, under locational pricing of energy and transmission, combined with fixed transmission rights and transmission congestion credits for firm customers, these decisions can be left largely to the market. In particular, purchasers or sellers from new generators can be given the choice of paying the opportunity costs of the congestion they create or forming a consortium to request and pay for transmission upgrades, without adverse economic effects on existing users who hold transmission rights.[75] As a result, reliance on regulation can be reduced and the market can play a significant role.

3. *Efficient Use of the Transmission Grid*

Locational spot pricing and pricing transmission use as the difference in locational spot prices provide the foundation that ensures that the PJM transmission grid will be efficiently utilized by those who place the highest value on that use and are prepared to pay the marginal opportunity cost for use. Those who place high value on their transactions should be able to acquire fixed transmission rights that hedge those transactions against the potential for congestion costs. This system efficiently allocates incremental use of the grid to those whose transactions have sufficient value to be scheduled, given the degree of congestion and the congestion costs associated with that use. Every grid user will pay the incremental cost of transmission service, and hourly choices between alternative sources of energy and alternative transactions will be based on short-run marginal cost, consistent with actual grid conditions.

4. *Reduced Complexity, Cost Shifting and Gaming*

The underlying efficiency, transparency and internal consistency in the proposed transmission and energy pricing scheme serve to reduce complexity, avoid cost shifting and minimize opportunities for gaming. As noted earlier, the calculation of locational marginal prices is relatively straightforward, since it is based on the actual dispatch which addresses the inescapable and traditional problems of determining a least-cost dispatch. Because LMP prices are based on the actual dispatch and bids, generators and loads can easily check the prices for consistency with the dispatch decisions. Thus, the prices paid to the generators should be consistent with their dispatch status. For example, each generator can verify that if called upon to operate, the prices paid to them will be sufficient to cover their costs, or conversely, if not

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75 The option for specific uses to be allocated the incremental costs of upgrades is provided in Section 27 of the Tariff.

called upon to operate, that operation would not have been profitable given the LMP paid to generators.[76] Similarly, the prices charged to LSEs should be consistent with the dispatch of their price-flexible loads, if any. This direct, decentralized and informal auditability is a basic advantage relative to alternative pricing systems in which the price is based on a hypothetical dispatch that is different from what actually happened in the hour.

By pricing congestion directly, the Supporting PJM Companies' proposal also avoids the need to sweep congestion costs over a zone into "uplift." Using an uplift to recover congestion costs is a much-criticized feature of the system used in the United Kingdom. This feature usually complicates the determination of market-clearing prices and distorts locational prices, resulting in inefficient incentives for incremental generation, consumption, transmission use and locational investment decisions.[77] The larger the "zone," the greater the complications. For example, failing to charge directly for transmission congestion would result in inefficient use of the transmission grid for low-valued purposes, because grid users would not pay the full opportunity cost of the transmission capacity they utilize.

In contrast, the Supporting PJM Companies' proposal not only simplifies price calculations and provides consumers with the right incentives but also enhances transparency because it reduces the divergence between marginal generator bids and prices paid by nearby consumers. Thus, if a generator were not dispatched in the same hour in which local customers paid prices that were higher than the generator's bid, the generator would know under LMP pricing that something was amiss and required investigation. The combination of low prices paid to generators and high prices charged to consumers could be a routine occurrence, however, in systems that rely on "uplift" rather than congestion pricing. For this reason, pricing systems based chiefly on uplift rather than LMP frustrate the ability of participants to gauge the impartiality of the dispatch without a full audit.

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76 Because explicit prices will not be calculated for the day-ahead commitment under the proposed settlement system, generators relying on the SO for day-ahead commitment would not be able to make a similar simple audit of commitment decisions based on day-ahead prices. They would, however, be able to test the commitment against real-time prices, although changes in weather conditions and unit availabilities could confound such a comparison. This is an area in which it may be possible to improve the PJM system over time.

77 Steven Stoft, "Analysis of the California WEPEX Applications to FERC," Program on Workable Energy Regulation, University of California, October 15, 1996.

The proposal also avoids cost shifting by providing comparable access and pricing to all users and by pricing energy and transmission on a locational marginal basis, rather than through some averaging scheme. The latter feature helps ensure that native load customers (who will pay the fixed costs of the existing grid) do not subsidize the use of the transmission grid by other customers.

LMP pricing also reduces the scope of gaming strategies both by avoiding uplift and because generators that seek to game the dispatch through schedules that create transmission constraints are not insulated from the financial consequences of their schedules. An alternative to using LMP prices to resolve congestion would be for the SO to make "constrained-off" payments, that is, payments to generators to reduce their output as necessary to balance the grid. These payments are not needed under an LMP system, because the LMP is the market-clearing price at every location. Any alternative pricing system inherently includes the possibility that prices paid generators will deviate from the market-clearing price, and if so that generators may find it economic to generate more energy than is needed, thus creating a need for the SO to have a mechanism, such as "constrained-off" payments, to get those generators to back down. Any such payments, however, would provide generators with an incentive to bid in ways that would game the system -- that is, by adopting bidding strategies that would increase their "constrained-off" payments, instead of bidding at their costs. Minimizing the need for "constrained-off" payments is thus another advantage of using LMP.

E. Firm Transmission Service Equivalence Through Financial Hedges

1. Overview -- Transmission Price Certainty

Under an LMP system, the price of energy at each location in the transmission system is the marginal cost of supplying an increment of load at that location, taking into account both generation costs and the characteristics of the transmission grid. In such a system, the short-run price of transmission over the existing grid is the difference in locational spot prices between the withdrawal bus and the injection bus. LMPs will vary across space and time, reflecting the inability of sufficient lower-cost generation to meet all loads in areas with constrained transmission and the need to dispatch higher-cost (out-of-merit) generation in those constrained areas. The volatility of LMPs also implies volatile transmission prices between locations.

While much of the volatility of locational prices will be recurrent and predictable, there will also be the potential for long-term changes in the electricity market that more or less permanently change the locational prices and the resulting transmission prices. For example, changes in the relative level of coal and gas prices could lead to long-term changes in the amount of congestion between the region encompassed by the East Central Area Reliability Coordination Agreement (ECAR) and PJM or even within PJM. Similarly, construction of new generation could lead to a long-term increase in the amount of congestion affecting transmission of electrical power between regions within PJM or even within utility service territories. Transmission customers will be able to obtain access to the transmission grid even during times of constraint by paying the incremental congestion costs (transmission congestion charges). However, given the potential for significant and long-term changes in congestion, and thus in the price of transmission, generators and loads seeking to enter into term contracts for the purchase and sale of electrical energy (either in the form of physical bilaterals or contracts for differences (CFDs))[78] may value a mechanism that provides them with a degree of long-term price certainty for the transmission costs associated with these term contracts. Market participants therefore will likely seek either long-term rights to use the transmission grid or some long-term financial protection against variations in congestion costs. This is a function that FTRs can efficiently serve. Equally important, FTRs can easily perform the similar functions FERC intends for its capacity reservation tariffs (CRTs).

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78 A contract for differences is a bilateral contract to buy and sell power that is settled against the spot price. For example, a buyer and seller may agree to buy and sell 100 MW of energy at Bus A at $30/MW hour. This transaction could be structured either as a CFD or a bilateral sale and purchase of transmission. If structured as a CFD, the seller could bid its power into the pool and be paid the spot price, while the buyer purchases power from the pool at the spot price. The buyer and seller would then settle their contract by exchanging the difference between the contract price at A and the spot price. This would be one form of a CFD. It should be recognized that a great many variations on the structure of CFDs can and will exist and this is only a simple example. One characteristic of a single-settlement system with advance commitment such as proposed by the Supporting PJM Companies (a one-settlement system is one in which generators and loads settle through the SO only for their actual real-time injections and withdrawals from the transmission grid; under a two-settlement system, generators and loads would also have the opportunity to enter into day-ahead contracts coordinated by the SO -- these day-ahead contracts would provide the basis for the second settlement), is that generators entering into CFDs can hedge their contractual operation by committing their units and allowing them to be dispatched by the SO. Such generator contracts would not be fully hedged if they were not committed.

It has been suggested elsewhere that third parties may be willing to provide short-term price insurance to protect traders from the volatility in transmission congestion charges, but any third party would be providing just that -- insurance -- and there is no compelling evidence from other energy markets that third parties will assume long-term transmission price risks for modest premia. The SO is the only entity able to provide FTRs that are true hedges, in the sense that they are backed by the revenue from grid congestion and, hence, reduce risks for both parties; it is inherently less risky, and hence less costly, to provide such hedges than to provide insurance.

2. *FTRs and Transmission Price Certainty*

The Supporting PJM Companies have addressed this need for transmission price certainty through a system of FTRs that entitle holders to receive credits for any transmission congestion costs between the points associated with the FTR.[79] Once a system of locational marginal prices is adopted for the pricing of electricity in the PJM control area, it is also possible to define a set of FTRs that hedge any transaction by payment of the congestion charges collected by the SO. These FTRs will enable buyers and sellers to hedge either short-term or long-term fluctuations in the price of transmission (i.e., congestion).[80] FTRs thereby permit buyers and sellers to enter into any term bilateral contract at a delivered price without incurring potentially large price risks associated with changes in transmission congestion within the market.

If the SO balances the transmission system and charges for transmission use based on locational marginal prices, then at times when the transmission grid is constrained the SO would collect more money from buyers of energy and transmission than it pays out to energy sellers.[81] This congestion "rent" would arise because when the transmission grid is constrained, all load

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79 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.2.

80 If the demand for such hedges is low relative to the simultaneous transfer capability of the grid, then the price at which FTRs would trade in the market would not reflect any premium over the expected value of the congestion credits associated with each FTR.

81 If the transmission system were unconstrained, then the spot prices of energy would be the same at every bus (excepting losses) and no congestion rents would be collected. If the transmission system were constrained, however, the difference between prices of at least one set of injection and withdrawal buses would exceed the difference in incremental losses.

in transmission-constrained areas will pay a higher market-clearing price, but the generation supplying part of the flows into the transmission-constrained area will be paid at the lower market-clearing prices prevailing in the unconstrained area. Whether transactions utilizing the grid take the form of physical bilaterals, spot purchases and sales at the pool price, or the purchase and sale of balancing energy through the SO at times when the transmission grid is constrained, the SO would take in more money overall than it would pay out, reflecting the limited ability of the transmission grid to reliably transfer (inframarginal) energy from the low-priced regions to the high-priced regions. Each unit of energy transferred to the constrained region would cause the SO to collect, in the form of congestion payments, the difference between the locational marginal price at the location where the energy is consumed and that location where the energy is injected.

FTRs provide a mechanism for distributing (or assigning ownership to) the congestion credits collected by the SO. Because congestion credits collected by the SO would be paid to FTR holders the mechanism also assures that the SO would not benefit from creating congestion or increasing the level of congestion credits. The SO would be simply a conduit for the distribution of the congestion credits. There would be no incentives for the SO to deviate from the economic dispatch or to create system congestion, because any increased congestion credits that would result from such behavior would be distributed to the holders of FTRs, with no residual congestion payments left for the SO. The problem of supervising the SO and transmission grid owners would thereby be reduced.

Under the Supporting PJM Companies' proposal, all entities using the transmission grid will pay congestion costs for their actual use of the system. All entities acquiring any form of firm transmission (either network transmission service or firm point-to-point transmission service) will acquire fixed transmission rights corresponding to the points of receipt and delivery for which firm transmission service has been obtained. Each FTR will entitle the holder to the payment of the congestion credits (if any) associated with the FTR receipt and delivery points. Once acquired in conjunction with the firm transmission service, nothing in the Supporting PJM Companies' proposal would preclude the FTRs from being freely tradable in a secondary market as purely financial instruments.

The FTRs as described by the Supporting PJM Companies correspond to the transmission congestion contracts -- "TCCs" -- that I have discussed elsewhere,[82] and are functionally and financially equivalent to the capacity reservations described by the FERC in the CRT NOPR. While every entity using the transmission grid, either directly or indirectly, will pay the cost of congestion when the transmission grid is constrained, FTRs will hedge the cost of congestion for firm transmission customers.[83] Importantly, the proposed forms of network and point-to-point service, with the associated system of FTRs, replaces the one-dimensional, contract-path-oriented transmission capacity notion with the standard of simultaneous feasibility.[84]

Thus, while a firm transmission customer will face locational marginal cost pricing of congestion at the margin, its average cost of transmission will be determined by the charges it pays for firm service. An entity with firm transmission service (and thus FTRs) could choose to inject and withdraw power from the grid to match its FTRs. In this case, the transmission congestion charges it pays will be offset by the transmission congestion credits it will receive.[85] As a result, the customer's only cost of using the grid would be its firm transmission payments contributing to recovery of embedded costs and charges for losses. Thus, the cost of firm transmission service between the receipt and delivery points specified for that service would never exceed the embedded cost of service. These fixed transmission rights mesh with the short-run pricing of energy and transmission to provide transmission grid users with the

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82 S. M. Harvey, W. W. Hogan and S. L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," August 7, 1996 (revised October 14, 1996 and filed at FERC on October 21, 1996, by W. W. Hogan as part of comments on FERC's CRT NOPR). W. W. Hogan, "Contract Networks for Electric Power Transmission: Technical Reference," Harvard University December, 1991; W. W. Hogan, "Electricity Transmission Policy and Promoting Wholesale Competition," Harvard University, August 7, 1995, FERC Docket No. RM95-8-000; W. W. Hogan, "Coordination for Competition in an Electricity Market", Harvard University, March 2, 1995, FERC Docket No. RM94-20-000.

83 One exception is that the initial proposal of the Supporting PJM Companies does not price loop flow through the PJM grid associated with generators and loads located outside PJM.

84 Open Access Tariff, Sections 13.5 and 32.

85 FTRs as defined by the Supporting PJM Companies are similar to the transmission congestion "obligations" that I have described elsewhere (see S. M. Harvey, W. W. Hogan and S. L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," August 7, 1996 [revised October 14, 1996], pp. 40-50), and share with TCC obligations the property that they are decomposable. Thus, an FTR from A to C is equivalent to an FTR from A to B and from B to C.

functional and financial equivalent of physical capacity rights, without the trading complexity that would make narrowly defined "physical" rights unworkable.

The combination of transmission congestion charges, fixed transmission rights and transmission congestion credits may at first appear to be unnecessarily complex, first charging grid users for use of the transmission grid and then returning to FTR holders these same congestion charges. Indeed, if grid use corresponded exactly in each hour to the ownership of FTRs, then the congestion charges and credits would cancel out. One of the purposes of an open access transmission system coordinated by the SO, however, is to enable grid users to reconfigure their transmission reservations to reflect their actual use of the system. In the real world, a transmission customer's use of the grid will not and should not always coincide with its long-term fixed transmission rights. In this event, the entity that has paid the fixed costs of the transmission grid will not be the entity that uses the transmission grid, so the transmission congestion charges and transmission congestion credits paid and received by the actual grid users would not cancel out. Thus, although all users will pay transmission congestion charges, non-firm transmission users and users who do not match their initial FTRs will not receive congestion credits for their transmission use unless they have purchased FTRs in the secondary market.

Thus, under the Supporting PJM Companies' proposal, grid users that do not own FTRs corresponding to their use of the system will pay the opportunity cost of the scarce transmission capacity they utilize in the form of transmission congestion charges. FTR holders who do not use the transmission capability corresponding to their FTRs will receive (in the form of transmission congestion credits) the opportunity cost of the scarce transmission capacity whose use they forgo. As already noted, when the SO collects these payments from users and then redistributes them to FTR holders, it will be coordinating an implicit "trade" of the right to transmission service for the period and amounts covered by the payments, with the actual grid users paying the FTR holders the opportunity cost of transmission as the price of temporarily using the FTR. FTRs thus provide firm transmission customers with the financial equivalent of firm transmission service with tradable capacity reservations within an overall system of flexible point-to-point service.

As discussed above, failing to charge for transmission congestion would result in inefficient use of the transmission grid for low-valued uses, because grid users would not pay the full opportunity cost of the transmission capacity they utilize. Failing to pay transmission rights owners for transmission capacity whose use they forgo would have the same effect, as the FTR owner would then have little or no incentive to forgo use of transmission capacity for low-valued purposes.

Since the actual use of the grid by transmission customers on a minute-by-minute basis will inevitably differ considerably from their advance reservations of transmission capacity, one can think of the role of the PJM SO as to rearrange and coordinate trades of these transmission reservations in real time, with the exchange of capacity reservations (FTRs) based on their value as measured by the real-time opportunity cost.[86] The trading is envisioned in the CRT NOPR and is implicit in the economic dispatch decision, which is a key feature that makes the short-term trading system workable.

Thus, while firm point-to-point transmission service customers will receive FTRs for specific points of receipt and delivery,[87] including between points within the PJM control area, they will be able to use the transmission grid as they wish up to the limit of their firm capacity reservation without paying for additional firm or non-firm service.[88] This use can include any combination of receipt and delivery points, not merely the receipt and delivery points for which the customer holds FTRs. Thus, transmission service provided to firm point-to-point customers is not limited to particular receipt and delivery points. The incremental charges for the reconfigured non-firm service will simply be the congestion costs associated with the reconfigured service, while the firm point-to-point transmission service customer will be paid the transmission congestion credits associated with the FTR that it is not utilizing.

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86 For a further elaboration of this discussion of the relationship between the CRT and a pool-based competitive market with TCCs (FTRs) see S. M. Harvey, W. W. Hogan and S. L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," Harvard University, August 7, 1996.

87 Interconnection Agreement, Schedule 7.01-2, Appendix B, Section B.2.2(c).

88 Open Access Tariff, Sections 13.7 and 22.1.

This substantial flexibility means that the financial hedges defined by FTRs are superior to strictly physical transmission rights, because the FTRs can be honored regardless of the changing patterns of the actual dispatch of the transmission system. Furthermore, since FTR holders are compensated for their financial right regardless of how they actually use the transmission grid, the proposal avoids cost shifting and incentives for inefficient use of the grid.

3. *FTRs and Least-Cost Dispatch*

Because FTRs would be purely financial instruments, they would impose no constraints on the actual dispatch. Thus, unlike must-take power contracts, must-run generation or strict physical transmission rights, FTR ownership alone would not affect either line availability or transaction scheduling. The economic dispatch consistent with the physical configuration of the grid would be determined by the SO without regard to FTR ownership. Further, FTR ownership would not confer operational control over, or an exclusive right to use, any transmission facility; in fact, FTRs would not be defined with reference to particular transmission facilities. Instead, an FTR owner would simply receive the difference between the congestion credits of a specified number of MW at two different buses, without specifying or needing to specify any particular transmission path between those buses. This separation of the ownership of the financial benefits of the grid from the control of the operation of the grid provides a natural way to move to a competitive market where all uses of the transmission system are treated in a non-discriminatory way.

If they choose, holders of FTRs could schedule bilateral transactions that match their FTRs. In this sense, the dispatch would be affected by the schedule, not by ownership, of the FTR. However, the FTRs, coupled with locational pricing, provide an economic incentive to avoid such inflexible schedules, since the FTR owner can realize the value of its transmission rights whether it actually schedules its generation or its loads are met by the SO's coordinated scheduling at lower cost.

4. Secondary Market for FTRs

The Supporting PJM Companies have not specified how a secondary market for FTRs might develop, since this is something that can be left to the market itself. However, given the structure of FTRs, such a market could easily emerge and enhance the efficiency of the overall energy market. FTRs could be tradable in such a secondary market and any party could acquire FTRs on a long-term basis in the secondary market. The secondary market may be particularly attractive to parties seeking to hedge the cost of serving highly variable loads; they could potentially acquire FTRs covering a limited number of hours of the year from other FTR holders. The emergence of a secondary market would also ensure that the price of FTRs would reflect changes in expectations regarding the congestion credits that would accrue to individual FTRs after the initial allocation; such changes might result from changes in loads; entrance or exit of generators; or expansions of the transmission grid.

Although investments in the transmission grid are often lumpy and would require the cooperation of the owners of existing facilities, FTRs would be divisible and freely tradable in a secondary market. A secondary market could provide a ready source of transmission rights that would serve as an alternative to system expansion. The price of the FTRs should not rise above the expected congestion opportunity costs or the cost of incremental expansion of the grid. In this way, an unregulated market for FTRs fits the basic outlines of the FERC pricing policy. Transmission service would be obtained at the lesser of opportunity cost or the incremental costs of grid expansion. Those using the transmission grid without holding FTRs would pay opportunity costs to those who do hold the FTRs.

In some circumstance, secondary trading might not exhaust all the opportunities of value in the market, and it would be desirable to include provisions for reconfiguration of FTRs as outlined in the CRT NOPR. It would be an easy extension of the current proposal to incorporate such reconfigurations, as discussed below.

5. *Unregulated Financial Products and FTRs*

The existence of FTRs as financial hedges would not preclude, and would likely facilitate, the development of a wide variety of unregulated financial products for transmission service. Again, these possibilities are not addressed by the proposal but could well emerge from the market. In particular, unregulated markets for transmission service may coexist with and would likely be facilitated by the availability of FTRs. Such a product could be offered by any market participant and need not be regulated by FERC. Firms offering unregulated transmission hedges could acquire FTRs from the secondary market or by buying firm service from the SO and repackage these hedges for LSEs on any terms they found economically attractive. They could offer transmission service through the pool by nominating their customers' power into the grid and paying to the SO the spot price of transmission for their customers' injections and withdrawals. While the physical transmission service would be provided by the transmission grid, there need be no limit to the number of firms that could compete in offering flexible terms for this service.

The existence of FTRs could also facilitate development of a market in unregulated transmission service by providing firms offering this service with a mechanism to hedge their risks. Thus, in a market with FTRs, unregulated providers of transmission hedges could offer a variety of hedges for combinations of injections and withdrawals. The FTR owner would not control physical access to or dispatch of the transmission grid, but would simply nominate the injections and withdrawals of its customers, pay the spot price of transmission and be paid congestion credits on the FTRs it owns. Because the FTR would not control either access to or operation of the grid, its use and resale need not be regulated by FERC.

While all transmission service purchased directly from the SO would be priced on a spot basis (although potentially hedged by FTRs), unregulated transmission service providers would be able to offer their customers a wide variety of transmission service pricing systems. These providers could, for example, offer transmission service that:

- Could be interrupted under certain conditions.

- Would be available during certain hours of the day or days of the month.

- Would be available for a certain number of hours during the month.

- Would be available when certain rainfall conditions increased or decreased hydro availability.

- Would be available when the spot price reached a pre-determined level.

All of these kinds of transmission service could be offered by an unregulated transmission service provider, and that provider could hedge the risk of providing this flexible service through its ownership of FTRs. Indeed, one can think of FTR ownership, rather than physical transmission asset ownership, as constituting the core assets of such unregulated transmission service providers.

F. Transmission Grid Expansion

Proposals for transmission grid enhancements can originate with transmission customers that request firm transmission service pursuant to the application procedures enunciated in the Open Access Tariff.[89] The SO will be responsible for identifying the methods of providing the requested transmission service.[90] The Supporting PJM Companies' proposal envisions that the cost of transmission enhancements undertaken in order to provide firm transmission will be recovered from the entities requesting the firm transmission enhancements.[91]

Under the Supporting PJM Companies' proposal, necessary investments in transmission facilities need not be determined exclusively by an administrative process. Rather, the need for transmission upgrades would be driven more by market forces, relying as much as possible on the incentives of avoiding congestion payments derived from differences in LMPs and the costs of upgrades. The role of planning and regulation would be narrower, addressing the unavoidable interactions in the transmission grid. To a much greater extent than occurs today, investment

89 Open Access Tariff, Sections 19 and 32.

90 Alternatives to SO proposals would also be considered.

91 Owners Agreement, Section 6.5. Open Access Tariff, Sections 13.5, 15.4 and 27.

decisions would be made at the initiative and with the agreement of those required to bear the cost within such an environment. Differences in locational marginal prices and the desire to avoid congestion charges would provide economic incentives for expansion of the transmission grid, and FTRs obtained in conjunction with firm transmission reservations would provide price certainty without affecting the allocation of the existing transfer capability of the transmission grid.[92]

The efficiency benefits that flow from the use of locational pricing and FTRs can be illustrated by considering the limitations of a single-price electricity market, such as that utilized in the United Kingdom. Single-price markets do not efficiently account for network interactions and transmission constraints. Real world transmission constraints create "out-of-merit" generation and a growing cost problem that, in the United Kingdom, was originally spread across all system users, none of which individually had an incentive to incur costs to sponsor grid expansion. Under a single-price system, grid operators have no market-driven method to signal the need for particular grid expansions to those whose market activities will create the need for those expansions.[93]

These problems are alleviated under the Supporting PJM Companies' proposal. With transmission usage prices set equal to the difference between locational marginal costs, users of the system who are buying and selling electricity without a complete hedge through FTRs would face the short-term market-clearing price at each location. In the face of transmission congestion, the opportunity to avoid sustained locational price differences provides the proper incentive for market participants to identify, initiate and pay for investments in transmission facilities. Customers in constrained areas would have an incentive to pay for grid expansion to allow them to access lower-cost generation in other areas. Generators desiring to serve loads

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92 James Bushnell and Steve Stoft, "Electric Grid Investment Under a Contract Network Regime, *Journal of Regulatory Economics*, Vol. 10, 1996, pp. 61-79.

93 The United Kingdom has partially mitigated this problem by giving NGC (the National Grid Company, the SO in England and Wales) some responsibility for congestion-related uplift costs, which it can manage by improving dispatch efficiency, finding less costly ways to manage constraints and even investing in the grid. This has produced some reduction in uplift costs, but only by making the monopoly NGC/SO a larger player with its own commercial interests in the market and increasing the importance of the regulatory formula that determines NGC's revenue and incentives.

in constrained areas would also have an incentive to pay for grid expansions to allow them to access those loads without incurring congestion costs. The consequences would be reduced congestion costs and reduced out-of-merit generation.

However, these customers and generators will have an incentive to expand the grid only if they recognize and believe that after making an investment in the grid there would be some protection against any future congestion costs. FTRs provide a mechanism to award the benefits of transmission to those who pay for the transmission investment costs by protecting the holders from future changes in congestion costs. In theory, any financially responsible party should be able to request and pay for investments in the grid that expand feasible grid transmission capacity; in exchange, they should receive FTRs corresponding to any firm transmission service they reserve in conjunction with the expansion. These incremental FTRs would have no effect on previously allocated FTRs. Thus, those who reserve the firm service would be granted rights to locational compensation that would assure that future congestion would not deprive them of the benefits they would have purchased.

Well-defined property rights in the form of FTRs are vital to creation of a long-term transmission market. Without FTRs, a locational spot pricing system would lack a mechanism to define and transfer the economic benefits of transmission to those paying for the transmission capacity, including expansions. The traditional alternative to this market-driven procedure for transmission grid expansion would be to rely solely on regulator-determined grid expansion.

In the case of transmission investment, economies of scale and network interactions loom large, unlike the case for generation. Hence, because of economies of scale it is expected that for any given transmission investment there could be a material change in the pool prices through reduced congestion credits. In addition, the network interactions could create many potential beneficiaries. These facts typically would require that transmission expansions be organized by a consortium of transmission users, rather than by individual users. The consortium could negotiate a long-term contract that allocates the fixed cost of the expansion and the corresponding FTRs. The transmission owner, as a regulated monopoly, would build the lines in exchange for a payment that covers the capital cost and a regulated return. Under this arrangement, the transmission owner would probably not make transmission investments without long-run contracts signed by willing customers who would pay the fixed costs and recover any future congestion revenues. The transmission owners could, however, play an important role in analyzing grid expansion options and helping grid users identify cost-effective improvements for potential user coalitions, although these functions could perhaps more easily be performed by the SO. The SO would verify that the newly created FTRs would be feasible and consistent with the obligation to preserve the existing set of firm transmission rights on the existing grid. Hence, incremental investments in the grid would be possible anywhere without requiring that everyone connected to the grid participate in the negotiations or agree to the allocation of the new FTRs.

Despite the substantial role for market-driven prices and incentives, transmission grid expansion and pricing would continue to present a need for regulatory oversight. Since economies of scale and complex network interactions create incentives that are not wholly compatible with decentralized decisions in a market, there will be a continuing need to address network expansion as an integrated problem with regionwide implications. This suggests a continued role for a regional planning capability within or associated with an SO. For example, an SO could be used to review the operating reliability standards and evaluate the impacts of proposed transmission expansions. However, this evaluation need not extend to a central decision on the need or cost responsibility for transmission expansion. As described above, any interested party or parties would be able to propose a grid expansion that appears to be beneficial for grid users as a whole. An expected role of the states, an SO and FERC would be to review these requests for transmission expansion, examine the compatibility with the companion request for new transmission contracts and ensure an open process for all to join in developing combined transmission investments recognizing the interactions in the network, so that all grid expansion proposals would be open to all firms willing to pay their share of the cost of the expansion. When proposed expansions are oversubscribed, all participants should be permitted to share in the proposed expansion and have the option to participate in a further expansion.

There may also be situations where no coalition of grid users is able to agree to finance a grid expansion that appears to be beneficial for the system as a whole. As a backstop, the traditional method of approving and financing transmission investments could still be necessary. Thus, any interested party could propose a project and an allocation of its costs among those grid users who would benefit. The regulator would be responsible for enforcing requirements for existing transmission facility owners to support expansions and reinforcements, deciding which projects should go forward, allocating the cost of the incremental investment among those expected to benefit from its impact on locational spot prices and assigning the corresponding FTRs.

In short, state regulators could oversee grid expansion decisions, including siting decisions, much as they do today, but they would now have the advantage of information on congestion costs to help assess the economic justification and relative merits of potential expansions. Both the state and federal authorities may require approval of the pricing of grid expansion under cost-of-service or other regulatory principles. In many cases, the need for grid expansion could be determined by market forces, with system users asking for expansion and agreeing to pay for it in exchange for new transmission rights that would protect them from grid congestion costs. The transmission rights themselves would be traded in an unregulated market. The regulators would oversee enforcement of an obligation to expand the transmission grid when users agree to pay the cost of the expansion. Or, possibly only in some cases, the regulators may authorize the expansion while assigning the costs and new transmission rights to a consortium of users who would benefit in the aggregate, but who could not reach agreement on the allocations among the group.

Native customers of the grid-owning utility should be willing to continue paying the embedded costs of that grid in the market proposed by the Supporting PJM Companies as long as they are assured that they will continue getting the economic benefits they expected when the grid was built. These benefits include, for example, the right to buy low-cost energy from a distant generation market. Native customers can be assured of this benefit, without limiting competition for use of the grid, provided the locational congestion compensation under their LSE's FTRs is credited to the LSE when the local pool price exceeds the pool price in the distant market. This solves several problems: the existing grid is paid for at embedded costs by those who receive its benefits; competition in the spot market and in the secondary market for rights to locational compensation assures that the grid is used by those who most value it at any time; and native customers are protected from the effects of increased congestion.

G. Facilitating the Bilateral Market

Commercial transactions in a competitive electricity market would include bilateral agreements negotiated exclusively between buyers and sellers. The Supporting PJM Companies' pricing and access rules facilitate bilateral trades without subsidies or cost-shifts, while giving customers the maximum degree of flexibility and choice consistent with reliable operation of the common transmission grid.

Market participants will be free to make long-term arrangements or to rely solely on access to the short-term market. Contracts for long-term electricity supply, price protection and other competitive services could contain any terms and conditions that are acceptable to the parties and are feasible within the limitations inherent in the interconnected electric system. The centrally coordinated spot market will support bilateral transactions and provide all market participants with additional options for obtaining balancing services.

Although the SO offers unit commitment and dispatch as a service, traders are not required to submit their resources for inclusion in the unit commitment and dispatch optimization performed by the SO.[94] If the market participants can, or believe they can, make unit commitment and dispatch decisions more efficiently than the SO, they are able to do so, subject only to the requirement that they schedule their uses of the PJM control area bulk power transmission facilities with the SO. Thus, LSEs can, if they choose, self-schedule their generation to meet their loads rather than relying on the SO's day-ahead commitment. As another alternative, generators and LSEs can contract to buy and sell power through bilateral transactions, making their own commitment decisions and relying on the SO only for transmission service and congestion management.[95]

The spot market coordinated by the SO therefore does not displace bilateral transactions; to the contrary, it supports and facilitates them. The spot market enables imbalances in bilateral contract quantities to be readily balanced and settled. The spot market coordinated by the SO

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94 LSEs may use capacity resources needed to meet their reliability obligations to sell energy outside PJM, but only on a recallable basis. Interconnection Agreement, Schedule 7.01-1, Section 1.6.4.

95 Interconnection Agreement, Schedule 7.01-1, Sections 1.6.1, 1.6.3 and 1.6.9.

makes it possible to have forward bilateral commercial arrangements while separately coordinating the spot market interactions of physical delivery of electricity on the transmission network. The ability to obtain energy-balancing and constraint management services from the SO-operated spot market at bid-based prices is particularly valuable to small and undiversified traders who are not able to operate an internal spot market across their own owned or contracted resources.

An efficient short-run electricity market with a visible spot price allows bilateral contracts that can be used to share or shift the risks of price uncertainty, provide long-term electricity purchases and create a variety of new products and services. Bilateral commercial arrangements can be either a physical delivery contract, if this is what market traders want, or with an efficient SO-operated wholesale spot market available, they may be contracts for differences. A physical delivery bilateral contract allows traders to execute a contract by scheduling delivery of a specified quantity of electricity without participating in the SO spot market auction for energy. A CFD can provide sellers and buyers the ability to execute bilateral contracts without requiring physical control, while taking advantage of the SO's least-cost dispatch to meet the customer's loads. A CFD need only reference the spot market price and can be honored through a simple settlement process. CFDs, coupled with FTRs, provide full support for commercial transactions. In both cases, the option to buy and sell in the SO's short-term spot market increases flexibility, expands choices and allows imbalances in delivery or receipt of contract quantities to settle automatically at the spot market price. And, in both cases, the transmission congestion charge is identical; physical bilateral contracts pay the congestion charge explicitly as the difference in locational price at point of receipt and point of delivery, while CFDs pay the same charge, but it is bundled into the locational prices paid and charged for energy in the spot market.

H. Mitigation of Market Power

While LMP cannot neutralize horizontal monopoly power, compared to alternative proposals for organization of the market it does help to mitigate and discourage the exercise of market power. Once the transition is made to market-based pricing, the exercise of market power by generators in a region constrained by transmission congestion could, for example, raise the price paid by loads in that region. However, the use of locational marginal pricing would function to mitigate any market power in two important ways.

First, the close relationship between the prices paid to generators and paid by loads under LMP will facilitate competitive entry. Since loads in the constrained area would see the full locational price paid to generators, they would have an incentive to enter into long-run contracts with potential new suppliers, thus encouraging new entry. The benefit to the load of the long-term contract is a reduction in its cost of power. The benefit to the entrant of the long-term contract is assurance of sunk cost recovery. This close relationship between the actual prices paid by loads and paid to generators will typically not exist under non-locational pricing systems, which typically rely on some form of price averaging that invariably creates a difference between what loads pay and what generators are paid. Absent such a relationship, loads will lack an incentive to enter into contracts with potential entrants in transmission constrained regions, and entrants may be deterred by the threat of much lower prices following entry with no mechanism to lock in sunk cost recovery.

Second, the close relationship between the prices paid to generators and paid by loads under LMP will also maximize demand-side competitive pressures. Once again, generators in transmission-constrained regions cannot exercise market power under LMP without raising the prices paid by load in the local region. This will concentrate the demand response within the constrained region and tend to lower prices, reducing the profitability of the exercise of market power. As before, this close relationship between the prices paid by loads and paid to generators will typically not exist under non-locational pricing systems. For example, if prices were averaged across the entire PJM control area, the exercise of market power within a transmission-constrained region would raise prices paid by load outside the constrained region, but the price increase within the constrained region would be softened by the area-wide averaging. There would therefore be less demand response by the consumers in the constrained region to whose demand response the exercise of market power would be most vulnerable.

In addition, central coordination of the use of the transmission grid by the SO helps mitigate market power in two ways. First, the SO's non-discriminatory central coordination of the day-ahead schedule to take account of transmission congestion avoids the potential for artificial limitations on the scheduling of out-of-merit generation that would facilitate the exercise of market power in transmission-constrained regions. Second, the SOs coordination of financial, rather than physical, transmission rights avoids artificial congestion by traders seeking to exercise market power. Artificial congestion could occur under a purely physical rights regime by rights holders simply refusing to relinquish their rights to others and tying up transmission capacity but with no intention of using it. In effect, these strictly physical rights would reintroduce vertical market power. This would create limitations on the use of the transmission grid even though capacity was actually available. In contrast, in a system with financial rights -- FTRs -- the SO is free to make maximum efficient use of the grid, allowing even those who are not the holders of FTRs to use the grid providing they pay the congestion charges. The actual holder of the FTR would not be allowed to preclude others from using the grid if it chose not to use it, but it would be compensated for the use by others through the SO's rebate of any congestion charges to the FTR holder. In effect, transmission unused by the FTR holder would be implicitly traded through the SO to the new user, with the trading price set at the level of the congestion charge, reflecting the marginal opportunity cost of transmission.

V. OTHER ISSUES

The essential elements of the Supporting PJM Companies' competitive market proposal are economically sound, and there should be general support for these elements once they are clearly understood. In addition, the Supporting PJM Companies expect that the initial elements will evolve as participants in the new market structure gain practical experience with the rules. In anticipation of this natural evolution, the Supporting PJM Companies are continuing to consider refinements of various elements for possible use in the future. There are details regarding the structure that inevitably balance advantages and disadvantages and the best compromise may not be obvious. There may also be a spectrum of views and perhaps suggestions that might enhance the Supporting PJM Companies' proposal over time. In this section, I discuss several topics that the Companies and other market participants could consider as they seek to enhance a market structure and rules that are already fundamentally sound. The topics are:

- Is a one-settlement system sufficient? Is a two-settlement system preferable?
- Should FTRs be "options" or "obligations"?
- How should the participants initially allocate FTRs?
- How should recovery of the sunk costs of the transmission grid be allocated?

A. One-Settlement versus Two-Settlement Systems

In the market structure proposed by the Supporting PJM Companies, generators and loads may submit voluntary bids and/or schedules to the SO in a day-ahead scheduling process. The SO will use the bids to determine the merit order for each hour of the next day, committing resources to ensure that all forecast loads not met by self-scheduled or other bilateral transactions are met reliably at the least cost, while ensuring that all transmission constraints are met. After the SO determines the least-cost dispatch schedule consistent with such constraints, it will notify the schedulers and bidders so that they can plan their operations to meet the next day's dispatch. However, in a one-settlement system, the day-ahead schedule does not create any financial commitment by generators, loads or transmission users, and the implicit market-clearing prices associated with the day-ahead schedule are not used for settlements. The only financial commitment arising from the day-ahead unit commitment scheduling process is the SO's obligation to pay each scheduled generator its as-bid costs (including no-load and startup costs) for the day, if those cost are not recovered in the hourly energy prices. In the actual day, the SO then coordinates the dispatch in real time and determines the market-clearing price.

The market structure proposed by the Supporting PJM Companies for the initial stages is a variation of a pure "one-settlement," in contrast to a "two-settlement" system. The essence of a pure one-settlement system is that the generation suppliers are paid at the market-clearing price (the LMP) for the amount they actually inject (not the amount they schedule) at each location and loads pay the market-clearing price (LMP) for the amount they actually withdraw (not the amount they schedule) at each location. Entities who schedule bilateral transactions settle any deviations from their schedules at the LMP and pay for transmission for their schedules at the difference in the LMPs for the points of delivery and receipt. In its simplest form, a one-settlement system does not include any obligations for commitments or deviations from amounts scheduled in the day-ahead period. The system proposed by the Supporting PJM Companies is not a pure one-settlement system, as the SO reviews bids and schedules a day in advance and coordinates unit commitment. Hence, it could be described as a "one-settlement system with commitment."

The Supporting PJM Companies have chosen to begin the new market structure with this approach in order to simplify the initial transition from the current system and to allow the new structure to commence as soon as possible. This appears to be a reasonable judgment given the fact that the initiation of the new market structure is planned for early 1997. At the same time, the Supporting Companies are aware that various issues arise that must be addressed in any proposal for a one-settlement system. The first is the need for system operators to ensure that, in a competitive market with many participants, those who schedule and bid in the day-ahead market intend to implement their schedules in real time and have the incentive to do so. In the interest of reliability and because of the lead times required for some resources to be available, operators need some assurance that scheduled resources will be available to match actual loads. Absent these assurances, operators would need to schedule (and charge customers for the costs of) excessive reserves in order to maintain current reliability levels. Another concern is to ensure that market participants have neither the ability nor the incentive to game the scheduling process in ways that artificially raise the cost of meeting load while potentially also reducing reliability.

The Supporting PJM Companies have dealt with these kinds of concerns by relying on penalties imposed on entities who fail to perform as scheduled. The penalties are intended to discourage gaming and encourage participants to follow through with the day-ahead schedules. One set of issues that arises is whether the size of the penalties is appropriate and whether the penalties are applied in a non-discriminatory manner, regardless of the type of transaction or market participant. Assuming these issues are dealt with, a more fundamental issue is whether a system is efficient when it discourages market participants from responding to changing market conditions during the day before the real-time dispatch. While the SO must have the ability to make such changes in real time as it responds to actual grid conditions, in theory, efficiency would benefit if traders could also revise their schedules to conform more closely to actual market conditions as those conditions become apparent closer and closer to the time when the SO must assume control. Imposing penalties on such changes could, if overdone, harm efficiency.

In recognizing these issues, the Supporting PJM Companies are considering moving toward a two-settlement system. In a two-settlement system, these issues are approached in a different way. The day-ahead scheduling market is set up as a separate market that opens and then closes at a fixed point in time. When this market "closes," the confirmed schedules (which the SO will ensure are consistent with all transmission and reliability constraints) become binding financial obligations. Generation and load scheduled with the SO become, in effect, forward sales and purchase contracts between the generators and loads. These implicit contracts create a financial obligation to deliver or take power in the actual dispatch. Generators can cover their obligation to deliver by operating or purchasing power through the SO in real time, while loads can cover their obligation to take by consuming power or selling power back through the SO in real time. The important point, however, is that participants are now financially obligated to perform and are paid or charged at the market prices associated with the day-ahead market; this is the first settlement. If conditions then change and the SO's real-time dispatch is different from the day-ahead schedule, then the SO will settle any deviations at the market-clearing price associated with the actual real-time dispatch. This is the "second" settlement. In this system, the financial commitments at market-clearing prices provide, in effect, market-based "penalties," reducing the need for administratively determined penalties.

There is no obvious choice between these two types of settlement systems. The two-settlement system at least has the disadvantage of appearing somewhat more complicated; I understand it would require some additional software development to implement. It has the advantage of providing system operators greater assurance that sufficient flexible resources will be committed and available to allow the operators to carry out their real-time balancing and reliability functions through purely market-determined incentives. It also provides traders with a day-ahead forward market in which traders can, if they choose, buy and sell back energy in real time, with trading priced at the difference between the real-time market-clearing price and the day-ahead market-clearing price. The use of a binding financial commitment at the close of the day-ahead market would also discourage gaming.

Another difference is that the two-settlement system has a defined market-clearing price against which day-ahead schedulers and bidders can audit the SO scheduling and dispatch decision for the day-ahead market. Because explicit prices will not be calculated for the day-ahead commitment under the Supporting PJM Companies' one-settlement system, generators relying on the SO for day-ahead commitment would not be able to make a simple audit of commitment decisions based on day-ahead prices. They would, however, be able to test the commitment against real-time prices, although changes in weather conditions and unit availabilities could confound such a comparison.

A two-settlement system also entails different risks for buyers and sellers compared to a one-settlement system. The Supporting PJM Companies would need to evaluate and understand the relative risks as they consider possible changes in the settlement system.

The essential features of the Supporting PJM Companies' proposal do not dictate which system should be used. Hence, the basic proposal could be implemented as either a one-settlement or a two-settlement system.

B. Should FTRs Be "Options" or "Obligations"?

FTRs as defined by the Supporting PJM Companies are very similar to the transmission congestion contracts that I have described elsewhere.[96] However, the FTRs initially proposed by the Supporting PJM Companies would entitle the holder to payments from the SO but they would not have required payments to the SO in the event that the congestion credits associated with the FTR were negative.[97] In the context of TCCs, this one-way approach is an "option." In contrast, if the transmission rights carry not only a right to receive congestion credits when the credits are positive but also an obligation to pay credits to the SO whenever they are negative, the rights are an "obligation." This terminology conforms to the same usage in the CRT NOPR. In response to various stakeholder comments on this issue, the Supporting PJM Companies have modified their proposal to make FTRs function as "obligations."

For some, it may go against the grain to think of a transmission "right" as involving something that may require the rights holder sometimes to pay a credit rather than receive one. However, in theory, the obligation is economically and logically correct; negative credits will sometimes arise in a congested grid with loops and counterflow, so that the locational marginal price at the point of injection is actually higher than the price at the point of delivery. Moreover, because counterflows have the effect of relieving congestion, they make it possible for additional flows to occur in the congested direction and thus allow the SO to assign additional FTRs.

In their original proposal, the Supporting PJM Companies would have accounted for the effects of counterflows in order to accommodate the additional flows and assign the associated FTRs. However, they also proposed that when congestion required those holding the "negative" FTRs to pay, the payments would be set at zero. There was a recognition that the combined effect of these two actions could produce situations in which the revenues collected by the SO for congestion charges would have been insufficient to credit all holders of FTRs, thus requiring a pro-rata allocation of FTR credits. Without this pro-rata reduction, it would have been

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96 See S. M. Harvey, W. W. Hogan and S. L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," August 7, 1996 (revised October 14, 1996), pp. 40-50.

97 See Interconnection Agreement, Schedule 7.01-2, Appendix B, Sections B.2.3, B.2.4, and B.2.5.

necessary to restrict the number of FTRs allocated to a smaller set, so that the SO would always be able to credit all allocated FTRs. However, defining this feasible set for an "options" type of FTR is computationally complex, so the pro-rata approach appeared to be a simpler solution.

One of the implications of this "options" approach is that FTRs could not be perfect financial hedges in all cases. After considering the issue further and discussing the merits of FTR "options" versus "obligations" with stakeholders, the Supporting PJM Companies agreed to modify their original proposal to conform with the "obligations" form of FTRs. Thus, firm transmission users whose FTRs are associated with counterflows will be obligated to pay under their FTRs, just as users whose FTRs are associated with the opposite flows are entitled to receive a credit from the SO. As a result of this change, the FTRs will allow traders to fix transmission prices in advance with substantially less risk that SO credits will be insufficient to cover all allocated FTRs.

There are two reasons why market participants acquiring such rights need not object to the resulting negative credits and the obligation to pay them to the SO. The first reason is that they are still perfectly hedged. In other words, these conditions imply that if the rights holder had used the grid in a manner consistent with its FTR, it would have paid the negative credit (as the rights holder) but also received the same credit from the SO (as the grid user), an exchange just the opposite of what would have occurred if the credit had been positive. In both cases, the two payments cancel each other, exactly the way a hedge should function. The second reason is that, given adequate information about the grid and the potential for flows resulting in negative credits, market participants who bid to acquire the FTRs should be able to take the expected negative-rent payments to the SO into account in deciding how much to bid for the FTR, just as they would have considered the expected positive payments (or congestion charges) from the SO in making that judgement. Thus, as the FTR market begins to function and market participants become familiar with it, potential FTR holders should discount the value of FTRs likely to be associated with negative credit payments.

A final consideration is that FTRs in the form of "options" share with TCC "options" the property that they are not decomposable. Thus, an FTR from A to C is not necessarily equivalent to an FTR from A to B plus an FTR from B to C. This feature means that traders cannot easily break apart their FTRs in ways that might facilitate beneficial trades in a secondary market. For example, were FTRs treated as "obligations," the market could choose to conduct trading with respect to one or more hubs, and all "obligation" FTRs could be restated in terms of "obligation" FTRs to and from a hub. This same restatement flexibility would not be available for the "option" version of the FTRs.

C. How Should the Participants Initially Allocate FTRs?

The Supporting PJM Companies have chosen to tie the initial allocation of FTRs to network service customers to the requirement that all LSEs in the PJM control area obtain firm transmission to the generation designated to meet each LSE's loads. This is an understandable response to the general concern about maintaining system reliability, a concern that has been echoed in California and the Pacific Northwest in light of major transmission and generation outages in recent months. This linkage means that LSEs will be acquiring fixed transmission rights to generators that are necessary to meet the installed reserve requirement but which during normal conditions might be used infrequently. During normal operations an LSE might prefer to own FTRs to locations in which there is lower-cost generation, so that the LSEs can hedge the cost of meeting their loads with those other supplies.

It is likely that after PJM begins operation under the new market structure, there will be a demand among market participants to be able to hedge alternative resources by either purchasing additional FTRs or reconfiguring their initial allocation of FTRs. Existing FTR holders, for example, could find it worthwhile to exchange their existing FTRs for different FTRs associated with more economic generation sources, while market participants without FTRs may want the ability to purchases FTRs to hedge their own transactions.

In the Supporting PJM Companies' proposal, the initial allocation of FTRs for integration network service within the PJM control area is tied to firm service to loads within the PJM control area. This firm service must be from a generator that is designated by an LSE under the reserve sharing provisions of the PJM Interconnection Agreement to serve the LSE's loads within PJM when needed. A designated generator may be located anywhere inside or outside the PJM control area, and the delivery of its power to the PJM load must be simultaneously feasible with the delivery by all other designated resources. Each LSE will acquire FTRs from these designated resources to the LSE's designated load points. Market participants may also acquire point-to-point service and will receive FTRs associated with those reservations.

In discussions with various stakeholders, it became clear that market participants may also want the ability to acquire FTRs within the PJM control area in order to hedge transactions with generators not covered by any of the initial PJM-load-based FTRs. After considering these concerns, the Supporting PJM Companies have chosen to provide point-to-point service within and into the PJM control area for any users who wish to make such reservations in exchange for incurring the obligation to pay the associated fixed costs of the system. This additional point-to-point firm service means that users will be able to reserve transmission and acquire FTRs for any points within the control area.

In the future, users may find it desirable to reconfigure the firm network service locations and their associated FTRs at any time or to sell firm point-to-point services and associated FTRs within the PJM control area in addition to the network service, to the extent consistent with simultaneously feasible delivery of the network commitments already made. Any such FTRs that differed by point of receipt from the network FTRs associated with the initially designated generation resource could only be arranged through the SO, not the secondary market, because of network interactions in defining the FTRs. Although FTRs with specific points of receipt and delivery could be traded in the secondary market, it is not possible to reconfigure or add points of receipt without reconsidering the interactions with all other FTRs, which dictates that such reconfigurations or additional allocations must be coordinated through the SO so that simultaneous feasibility of all firm transactions is preserved. Thereafter, these additional FTRs could be renewed as part of the SO's reservation of firm service. The availability of point-to-point firm service within the PJM control area provides an additional solution to this problem.

This additional firm service would be available to any participant willing to assume the obligation to pay the corresponding fixed costs of the grid and would be accompanied by FTRs between the points covered by the firm service. This type of enhancement may need additional software development, but it could in theory be accommodated easily within the proposed framework.

With the availability of this point-to-point service, it is possible that users will at least initially request more firm reservations within the PJM control area than are simultaneously feasible. To deal with this condition, it is likely that some type of auction administered by the SO will be necessary to allocate the reservations and the accompanying FTRs. There are a variety of means by which additional or alternative FTRs could be allocated among grid users. The details would need to be developed, but there is nothing especially complicated, in principle, when compared with other approaches that face the reality that whatever the definition of transmission rights, there will have to be an identification and explicit allocation of the rights to the existing system.

D. How Should Recovery of the Sunk Costs of the Transmission Grid Be Allocated?

The Supporting PJM Companies have chosen to tie recovery of the sunk costs of the transmission grid to the requirement that each LSE reserve network service to sufficient generation to meet its respective installed generation reserve requirements. While this approach is workable, it is also possible to decouple these concepts and still provide for full recovery of the fixed costs of the grid. The underlying allocation approach proposed by the Supporting PJM Companies requires that customers in each utility service area continue their existing responsibility to pay the revenue requirements -- i.e., the sunk costs and ongoing maintenance cost obligations -- of the utility in which the customer is located. This straightforward approach can work whether it is tied to an installed reserve requirement, as the Supporting PJM Companies propose, or independent of that requirement. While there are other acceptable methods to allocate responsibility for fixed transmission costs, this basic approach has the benefit, as does the Supporting PJM Companies' proposal, of not shifting fixed cost obligations between the various utilities who will be submitting their transmission to the SO's control.

VI. COMPARISON OF THE SUPPORTING PJM COMPANIES' PRICING PROPOSAL AND THE PECO PRICING PROPOSAL

A. The Importance of Efficient Pricing Mechanisms

There are important policy choices to be made at each step in the process of designing a competitive market structure and its supporting rules. These policy choices affect not only how electricity trading will occur but also the efficiency of the results and the allocation of the costs. None of these policy choices is more important than deciding the manner in which the market rules determine the prices that will be charged to customers and paid to generation suppliers. In a vertically integrated market, poor pricing signals would have little effect on performance or efficiency. In the past, therefore, close attention to the price incentives was less important. But the entire premise of the competitive market with decentralized decisions is the notion that prices can provide the right incentives for efficiency. Hence, the move to competition places great importance on the need to develop pricing mechanisms that can send efficient signals to consumers, generators and investors.

If the pricing mechanisms are consistent with competition, and there is no significant market power, the market structure should result in efficient competition that produces substantial benefits compared to traditional regulatory approaches. But if the pricing and congestion management mechanisms are inconsistent with a competitive market, it is unlikely these benefits will be realized, although a few well-positioned market participants may profit at the expense of others. If the pricing mechanisms are poorly designed, costs can be shifted easily from one set of traders to another, or from one set of customers to another, while total costs rise. The most likely result is that small traders and consumers will be disadvantaged, since the larger players will have a greater ability to shield themselves from the effects.

An inefficient pricing mechanism will inevitably require continual regulatory intervention to rectify and protect consumers from the effects of unfair or inefficient pricing rules. As the U.K. system has demonstrated, regulatory intervention would be needed to compensate for the pricing mechanism's failure to send appropriate signals regarding the use of energy, as well as the need for and location of investments in new generation, transmission upgrades and new loads. Inefficient pricing rules are therefore an invitation for continuing regulation at every level and a poor substitute for the efficient outcomes that should be available from a well functioning competitive market with an efficient pricing rule.

The Supporting PJM Companies considered these factors in developing their proposal. As a result, the locational market pricing mechanisms set forth in their proposal are fundamentally sound and provide a solid foundation for an efficient market. Moreover, since filing their initial applications with the FERC, the Supporting PJM Companies have continued to improve their proposal as they sort through the choices about how the details of their pricing mechanism will be implemented in practice.

The Supporting PJM Companies' pricing proposal is inherently efficient and consistent with a competitive market. Their proposal stands in contrast to the alternative proposal put forward by PECO. However, the differences between the two proposals and their effects on consumers and traders have not received sufficient attention and remain susceptible to varying degrees of misunderstanding and misinterpretation. In examining the two approaches and comparing their merits, it is therefore essential that FERC and state regulators, as well as all market participants, have a clear understanding of how these two approaches would work, what effects they would have on the behavior of market participants, and what effects each would have on the prices consumers pay and generators receive.

B. The Supporting PJM Companies' Locational Pricing Proposal

The Supporting PJM Companies' proposal is grounded on the principle that in a constrained electricity network, marginal costs will differ throughout the system. If there were no transmission constraints throughout a regional network, a competitive electricity market would result in roughly the same prices throughout the region, with prices varying within the region only because of the differences in losses. The entire regional market would clear at a price reflecting the region's marginal cost of production, and all customers throughout the region would pay more or less the same market-clearing price. However, the PJM region is not always free of transmission constraints. Depending importantly on load conditions, transmission and generator outages, and the extent of trading on the system, the PJM transmission network will sometimes experience congestion from thermal limits and voltage or stability constraints imposed to ensure system reliability.

When transmission constraints become binding, it will not be possible for consumers to satisfy all of their demands with power from the lower-cost suppliers. Confronted with too many demands from customers for generation supplies from lower-cost areas, the SO will have to curtail some of the lower-cost generation in the unconstrained areas and increase the output of higher-cost generation in the constrained areas. The SO's "redispatch" decisions will have the effect of raising generation costs in the constrained areas and lowering them in unconstrained areas, producing different market-clearing prices in each area. Hence, locational marginal cost differences are an inescapable consequence of constrained transmission networks.

In Appendix A, I present several examples to demonstrate how locational prices would be determined under a variety of grid conditions. These examples illustrate why locational prices differ when the grid is constrained and how prices can differ in unexpected ways.

In a competitive market, these locational marginal costs would determine locational market-clearing prices. The policy decisions that confront those who design pricing mechanisms and those who approve those mechanisms are therefore relatively straightforward: How should the pricing mechanism deal with these inescapable differences in locational cost differences, and what are the consequences for dealing with them under alternative rules?

The Supporting PJM Companies have chosen to acknowledge the locational differences in market-clearing prices and to use those prices as the logical basis for paying generators, charging consumers and pricing transmission. The effects of this decision are manifold but not necessarily obvious. One obvious effect is that buyers and sellers of electricity will face true market-clearing prices in each area, consistent with the realities of the network and the principle that different prices are the inevitable consequence of network constraints. Using these prices will therefore enhance the ability of the market to make efficient decisions regarding use, production, and investments and arguably reduce the need for regulatory intervention in each of these areas.

A more subtle effect is the fact that locational pricing will facilitate bilateral trading and allow multiple forms of bilateral trading to occur without shifting costs between competitive network users or shifting redispatch costs onto smaller traders and consumers who do not engage in bilateral trades. This effect, which I discuss in more detail below, is a lesson the Norwegians learned from the experience in the United Kingdom, and it has allowed the Norwegian competitive market to enjoy a compatible mix of centrally coordinated dispatch and decentralized bilateral trading. Bilateral trading occurs without cost shifting because efficient prices are charged for transmission usage, and the locational prices are the same for pool use and bilateral trading. However, this linkage has not been fully assimilated in all the restructuring debates in the United States.

C. PECO's Alternative Pricing Proposal

The alternative pricing proposal chosen by PECO and supported by some market participants does not directly acknowledge or use locational market-clearing prices.[98] Rather than pay generators and charge customers the true market-clearing prices in each area of a constrained network, the alternative pricing proposal would attempt to apply an administrative rule to impose a uniform price on the entire PJM region, notwithstanding the physical realities of the network and the locational implications for market prices in a constrained transmission network. Moreover, the uniform prices would be set at levels that would not reflect the true market-clearing prices anywhere in the region. Hence, the proposal attempts to charge something akin to average congestion costs, with some locational prices above and more below the average. In the face of congestion, the administrative rule would instead set the PJM-wide price at the price that would have occurred in the absence of any network constraints. Consumers would pay this uniform price plus an "uplift" to cover the added costs of payments to "constrained-on" generators whose output would be required to meet loads in constrained areas when there is congestion. Generators throughout the PJM region would be paid the uniform "unconstrained price," except that "constrained-on" generators would be paid their higher bid prices to induce

98 See PECO Energy Company's Open Market Plan, August 1996.

them to operate, since the bids of "constrained-on" generators would be higher than the uniform unconstrained price.[99]

While the notion of having a single, administratively determined price throughout the PJM region may seem appealing to some, policy-makers should consider the important consequences from accepting this approach.

- First, the PECO proposal shifts costs. While the PECO proposal attempts to reduce the prices paid by and to loads and generators and loads in constrained regions, it has a corresponding effect of raising the prices paid by and to loads and generators in "constrained-off" regions. Even if the PECO proposal had no impact on bidding behavior or participation in the pool, this effect of the proposal would raise the prices paid by loads in the "constrained-off" regions and could in practice raise rather than lower the total PJM wide cost of meeting load.

- Second, the PECO proposal will raise prices. PECO's administrative pricing rule would create incentives to change the behavior of any generators that participate in the SO's dispatch, with the result that the pricing rule would unambiguously raise the average price in the PJM region. That is, PECO's alternative pricing proposal would force all consumers to pay on average prices that would be consistently higher than the average market-clearing prices determined under the Supporting PJM Companies' proposal.

- Third, the PECO proposal is incompatible with a bilateral market. A corollary consequence is that the cost-sifting would induce participants to employ bilateral transactions and abandon the SO's dispatch, thereby eliminating the use of the

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99 In dealing with congestion, the SO must dispatch generation out of the unconstrained merit order. This means that in the constrained area, the SO would schedule generators with higher bids to run even though these generators had been rejected in the unconstrained dispatch. If these generators were paid only the price associated with the unconstrained dispatch, they would receive less than their bids and fail to recover their running costs if they operated. Thus, the unconstrained pricing mechanism used in the United Kingdom and the PECO proposal requires that the SO pay these "constrained-on" generators at their bid prices. If it did not do so, these generators would refuse to operate.

dispatch as a tool for managing congestion. This would leave the regulators with the necessity of either prohibiting direct bilateral trading, as in the United Kingdom, or forcing the SO to apply some other administrative means to allocate scarce transmission resources among the bilateral traders. In short, the PECO proposal is fundamentally incompatible with a market mechanism for managing transmission constraints in a market that allows bilateral trading.

The following discussion explains each of these effects.[100]

1. *The PECO Pricing Proposal Would Shift and Raise Costs*

Trades from "constrained-off" to "constrained-on" areas exacerbate congestion and require the SO to redispatch generation to maintain reliability. As explained above, the SO's redispatch would generally cause the market-clearing price to fall in unconstrained areas and to rise in constrained areas. However, the PECO pricing proposal would not pay generators the market-clearing prices in either location. Instead, the proposal would pay most generators a price determined from a hypothetical unconstrained dispatch. This hypothetical dispatch would include some lower-cost generators who would not actually be dispatched (because of the constraints) and exclude some higher-cost generators that actually would be dispatched to meet loads in the constrained locations.[101] If generators do not change their bidding behavior in response to this pricing mechanism, as PECO apparently assumes, then the price derived from this unconstrained dispatch would be less than the true market-clearing price at the constrained locations. At the same time, the unconstrained price would typically be higher than the true market-clearing price at the unconstrained locations. As a result, some generators would be paid more than the market-clearing price, while others would be paid less. Even if there are no changes in bidding behavior, the PECO pricing proposal would, in effect, shift payments from

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100 Appendix A starts with the example offered by PECO's witness, Charles Mann, and illustrates these conclusions, demonstrating that the PECO proposal results in both higher average costs and cost shifting.

101 It should be noted that PECO has not explained how the "unconstrained" price would be determined. In particular, would the unconstrained price be determined only with reference to the bids and capacities of units actually on line in the real-time dispatch? Or, would the unconstrained price be determined taking into the account all of the units that would have been available absent congestion? If the latter, what would be the source of bids?

generators in locations where generation is scarce to generators at locations where there is excess generation.

Costs would also be shifted between different customers. Under locational pricing, customers in low-cost areas should see lower market-clearing prices, but under the PECO pricing proposal, these customers would be charged prices higher than market-clearing prices for their location. In the constrained locations, assuming no change in bidding behavior, customers would be charged less than the market-clearing price. In effect, customers in unconstrained areas would pay more so that customers in constrained areas could pay less.[102] Whether the combined impact of the PECO pricing mechanism undercharging some customers and overcharging others would be to raise or lower the total cost of meeting load, assuming that generators bid their costs, is an empirical question. The direction of the overall impact would depend on the size of the "constrained-on" and "constrained-off" regions, the slopes of the supply and demand curves in these regions and how the "unconstrained" price would be calculated.[103]

The PECO pricing proposal would therefore distort price signals and provide inappropriate incentives for energy consumption and energy production. Some customers in low-cost areas would receive higher price signals, encouraging them to consume less, while generators in the same low-cost areas would be encouraged to produce more, even though additional generation in their locations could not be consumed locally or exported because of the constraints. All the incentives would be the reverse from what efficient locational prices would produce.

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102 Of course, if generators did change their bidding behavior, so that generators in constrained locations raised their bids to the market-clearing prices, then customers in constrained locations would not see lower prices either; they would instead pay something close to or above the higher market-clearing price, while their counterparts in the unconstrained areas would still pay more than they should. In a limiting case, the PECO proposal could, in principle, result in charging all customers the highest locational price across the system, even though many locational prices would be much lower.

103 Empirical estimates of these impacts are discussed in Section D below.

2. *The PECO Pricing Proposal Would Change Generators' Bidding Behavior and Further Raise the Average Price*

Much of the apparent appeal of the alternative pricing proposal is premised on the unrealistic assumption that the PECO pricing system can reduce consumer payments by paying some generators less than the market-clearing price. However, short of indefinitely maintaining regulatory constraints on generator bidding, there is no way to achieve this result, even if in theory it were an acceptable goal. Unless prevented by regulatory fiat, suppliers will invariably seek to obtain the market prices to which they would be entitled in a competitive regime, and they will adjust their bidding behavior to that end. This well-understood principle of market behavior applies to the PECO alternative pricing proposal.

In particular, the claimed savings of the PECO proposal are premised on the assumption that generators participating in the SO's economic dispatch would bid exactly the same way under the PECO pricing system as they would under a system that paid them locational market-clearing prices. Under locational pricing, generators participating in the SO's economic dispatch would be paid the market-clearing prices at their respective locations; they would thus have an incentive to bid their marginal costs. That is, under locational pricing, infra-marginal generators would have no incentive to bid above their marginal costs because: (1) if the market-clearing price were higher than their bid, they would be paid the market-clearing price; and (2) by bidding higher than its costs,. a generator would risk not being dispatched if it misestimated the market-clearing price.

As noted above, the PECO proposal would begin in the first instance with the "unconstrained" price. Except in rare circumstances, this unconstrained price would be higher than the locational market price in a region in which generators have been "constrained-off." Hence, even if bidders did not change their bidding strategies, some generators would be paid more than the locational price.

The incentive for a generator to bid its marginal cost would not be the same under the Supporting PJM Companies and PECO proposals, and the different incentives would likely encourage generators to change their bidding behavior under the PECO pricing system. To see the effects of this behavior, consider the options of generators in a "constrained-on" area. Within that area, under the PECO proposal, generators that would not have been dispatched but for the constraint would be "constrained-on" and paid their higher bid prices in excess of the unconstrained price. The PECO proposal would attempt to avoid paying all other generators in the "constrained-on" area the market-clearing price for their location, offering instead to pay all but the "constrained-on" generators a lower uniform price -- the unconstrained price -- regardless of the fact that higher payments would be made to "constrained-on" generators at the same location. Thus, PECO proposes to price-discriminate among generators, paying different prices to generators in equivalent situations, based on their bids. This is the source of the savings in the examples offered by Charles Mann, PECO's expert, in Exhibits CEM 7, 8 and 10 of the PECO applications. However, all generators in the area would know this pricing rule before formulating their bids. Once they realized that the SO would pay "constrained-on" generators their bid prices, all generators in the constrained area would have an incentive to raise their bids to the market-clearing price at their location, thus ensuring they would be paid the locational market-clearing price.[104] Thus, with perfect information, bidders would correctly guess the market-clearing price and be paid that price. This effect of the PECO alternative pricing proposal

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104 This effect of the PECO proposal could in principle be avoided if regulatory rules were imposed that required that all generators submit bids equal to their running costs. In order for the PECO pricing mechanism to work, however, such regulatory rules would have to be applied to every generator, even those lacking market power, and be maintained indefinitely. Furthermore, the combination of a regulatory policy requiring cost-based running cost bids and pricing mechanisms that preclude constrained-on generators from being paid more than their bids, could preclude generation in transmission-constrained regions that operates only when constrained-on due to transmission limits from recovering any of its fixed operating costs or any return of or on investment in energy prices. Such a system would therefore require that all of these costs be recovered in capacity prices or the regulated cost of service, if generation required for reliability in the constrained region were to remain in business. Unless the PECO pricing system were therefore accompanied by locational based capacity prices, it appears to preclude the profitable operation of generators in transmission-constrained regions, forcing them to cease operation if they were required to bid their costs. In practice, it is unclear how a cost based bidding requirement could even be implemented under the PECO congestion management proposal because the PECO proposal apparently does not include a day ahead commitment in which start-up and minimum load costs would be bid into the pool. In consequence, the start-up and minimum load costs of constrained on generators would need to be recovered in a margin over each units running costs, but under a system that paid each unit its running cost there would be no such margin. Moreover, this problem will be particularly intractible under the PECO proposal as there is no day ahead schedule by the ISO to either determine day ahead prices or commit generation in transmission constrained regions.

on generator bidding would eliminate the entire presumed savings in consumer payments ascribed to the PECO approach.[105]

Moreover, the change in bidding behavior induced by the PECO pricing mechanism would not only ensure that "constrained-on" generators would be paid the same prices they would under locational marginal cost pricing, but would further raise the price paid to generators in "constrained-off" regions above the market-clearing level. This additional effect would occur as "constrained-on" generators bid their estimate of the locational market price, rather than their costs, thus appearing to shift the unconstrained supply curve to the left (in). The magnitude of this change could be large and could quite possibly cause generators in the "constrained-off" region to be paid the locational marginal price within the transmission "constrained-on" region, thereby raising consumer costs.

Overall, PECO's alternative pricing proposal provides strong incentives for generators to change their bidding behavior in ways that uniformly raise prices. In particular, bidders in "constrained-on" areas would raise their bids to increase "constrained-on" payments and the unconstrained price. Hence, the asserted price advantage of the PECO alternative pricing scheme is an illusion, just as the claim that "the congestion problem is only a $4 million problem" is misleading. The true costs of congestion must be measured as the difference in locational prices; in a efficient market, higher market-clearing prices would be paid to all generators in the constrained areas, not merely to those "constrained-on." Further, because the PECO system would encourage bidders to change their bids, average prices would be higher under that system. Moreover, the higher prices would result from rational economic behavior on the part of bidding generators. None of this behavior would be induced or necessary under the Supporting PJM Companies' proposal to use locational market-clearing pricing.

105 In the absence of perfect information, bidders would either undershoot or overshoot the market-clearing price. Those who guessed low would receive lower payments, but still higher than they would have received under the PECO assumption. Those who guessed too high would not be dispatched, but they would be replaced by other generators with bids above what should have been the market-clearing price, raising costs even more. In any case, the "unconstrained price" charged to consumers would be higher than PECO assumes and could be as high as (with perfect information) or higher than (with overshoot bids) the average of the prices paid under locational pricing.

3. *The PECO Pricing Proposal Would Undermine Economic Dispatch and Could Require Prohibiting Direct Bilateral Trading*

Bilateral trading is seen as an essential element of a competitive electricity market. It is therefore important that market mechanisms accommodate and support bilateral trading in an efficient manner. The Supporting PJM Companies' proposal provides this essential support through an open spot market, derived from a bid-based dispatch. This dispatch provides an automatic balancing service for bilateral traders, allowing them to purchase or sell energy easily to make up for over- or undergeneration by bilateral traders relative to their loads. This mechanism also provides an efficient and non-discriminatory means to price transmission use on a constrained network.

As explained above, the true market value of energy will vary by location, both because losses vary by location and because transmission constraints will create locational differences in market-clearing prices. It follows that the value of balancing energy (balancing service) and transmission service bought and sold in the SO's spot market will also vary by location, depending on losses and congestion.

Under the Supporting PJM Companies' locational pricing proposal, bilateral traders will be charged locational marginal prices for both the energy they buy and sell in the SO's spot market and for transmission services. This pricing system is both non-discriminatory and flexible, as the consistency of the locational marginal prices for energy and transmission pricing allows the maximum flexibility for bilateral transactions. In other words, with spot trading and balancing priced at the market price at each location, and all traders paying for transmission use at a price based on the difference in locational prices, no trader can lean on the system (or on any other trader) to implement its trades. It will therefore be unnecessary for the SO to place artificial restrictions on bilateral trades under the Supporting PJM Companies' proposal, as there will be no cross-subsidization or averaging of energy or transmission prices that must be protected against arbitrage. This would not be the case under the PECO pricing proposal where such restrictions would be required.

If the PECO pricing proposal were adopted, a variety of bypass restrictions and subsidies would likely be required in order to make the system workable. The need for these restrictions would arise from the cross-subsidization and price averaging that underlie the PECO proposal. Absent restrictions on bilateral trades, traders disadvantaged by the price averaging in the PECO proposal would seek to bypass the price averaging through bilateral trades, causing the pricing system to collapse. Although not acknowledged by PECO, implementation of its proposal would require either restrictions on bilateral trading or an elaborate set of additional trading and transmission rules and payments.

In a system that gives traders the choice to participate in bilateral contracts or in a central economic dispatch to any degree they find commercially advantageous, we should expect traders to adapt their behavior to avoid the costs shifts inherent in the PECO proposal. One example of the need for trading restrictions under the PECO proposal arises with respect to pricing of energy in "constrained-off" regions. PECO proposes that generators in "constrained-off" regions be paid the price of power in a hypothetical unconstrained dispatch. Because the unconstrained price that PECO would pay generators in the "constrained-off" region would exceed the locational market price, there would be more generators in the "constrained-off" region seeking to sell energy at this price than the transmission grid could accommodate (it is precisely this surplus that is the reason that the locational marginal price in the "constrained-off" region would be less than the unconstrained price). One way to attempt to accommodate this surplus would be to make "constrained-off" payments to generators whose bids were less than the unconstrained price but who were not dispatched by the SO because their bids exceeded the locational marginal price. Confronted with the same problem, this approach was adopted in the United Kingdom. If adopted as part of the PECO proposal, "constrained-off" payments to out-of-merit generators would further raise the cost of power to customers in both the "constrained-up" and "constrained-off" regions, relative to the locational marginal price.

The PECO alternative pricing proposal does not appear to consider this issue, but PECO's subsequent descriptions suggest they do not propose to pay "constrained-off" generators anything to discourage them from operating. It is worth noting, however, that when the United Kingdom confronted this identical issue, it concluded that these generators should be compensated at their opportunity cost for the fact they were prepared to run at the going price but were not allowed to run. Thus, each "constrained-off" generator would be equally entitled to run, given the "unconstrained price," but would not be allowed to run, and there would be no basis for allowing some to run and be paid, but not others. Hence, in the U.K. system, all "constrained-off" generators are paid their opportunity cost. The opportunity cost is the difference between the "unconstrained price" and each "constrained-off" generator's bid.

Since the original PECO proposal did not consider this issue, it is not clear how the alternative pricing proposal would be implemented. If no opportunity cost payments were made, some mechanism would be needed to deal with claims of unequal treatment; if opportunity cost payments were made, as they are in the United Kingdom, then the "uplift" paid by consumers would be greater than PECO originally assumed in its analysis, and restrictions would still be required on bilateral transactions with generators located outside PJM.

If "constrained-off" payments were implemented, the PECO alternative pricing approach would have an additional effect on generator bidding incentives. In the U.K. system, generators who recognize in advance that they will be "constrained-off" have an incentive to lower their bids, since the "constrained-off" payment is based on the difference between the unconstrained price and their bid. Hence, under one possible implementation of the PECO proposal, generators would attempt to increase their "constrained-off" payments by reducing their bids to a level just above the price at which they would be dispatched, thus maximizing the "opportunity cost" calculated by the SO. The effect would be to further increase consumer uplift payments.

Absent "constrained-off" payments under the system proposed by PECO, generators not scheduled by the SO to operate at the unconstrained price would have an incentive to bypass the pool by entering into bilateral transactions with customers at prices slightly less than the pool "unconstrained" price. Each such bilateral contract would displace a transaction coordinated by the SO, requiring the SO to back down another generator and ultimately all of the generators in the "constrained-off" region with costs less than the unconstrained price would seek to enter into bilateral contracts with customers to avoid being backed down by the SO.

In effect, consumers and generators with opportunity costs below the unconstrained price would defect from the central dispatch and turn to bilateral arrangements. Thus, "constrained-off" generators would be able to offer mutually advantageous bilateral deals to consumers, reducing the loads served by the dispatch.[106] Not all of the schedules associated with these customer contracts could be honored by the SO, however, because of the transmission congestion that is the reason the SO could not dispatch all of the generators in the first place. This incentive of generators to bypass the price averaging features of the PECO pricing mechanism would leave no loads to be served by the dispatch and hence no market-based mechanism for managing congestion and allocating scarce transmission. The PECO pricing proposal contains the seeds of its own destruction as a congestion management tool in a system with bilateral transactions. This fundamental dilemma is the result of combining the conflicting principles of average-cost pricing and freedom to choose. Hence, a voluntary economic dispatch that uses average-cost pricing is inherently unstable.

Even if the PECO pricing mechanism were elaborated to provide for "constrained-off" payments to PJM generators, the price averaging elements of the system would provide additional motives for bypass. Loads in a "constrained-off" region, for example, would have an incentive to bypass the pool dispatch to avoid paying the "unconstrained" price for generation. This could be achieved by entering into bilateral contracts with generators outside PJM, unless "constrained-off" payments were expanded to cover these generators or additional rules were imposed to limit customers ability to enter into bilateral contracts with generators outside of PJM.

Thus, to preserve reliability and allocate transmission use under the PECO pricing mechanism, either the SO/regulators must prohibit bilateral trades that bypass the dispatch pool, as the U.K. system does, or some other administrative mechanism must be found to manage congestion. In short, in a competitive market with choice, a central pool whose prices are based on average costs cannot provide the incentives needed to support a market-based system for managing congestion. The PECO proposal is not a solution to congestion management. Instead, the PECO proposal would simply throw back to the SO the task of developing a new means for allocating limited transmission resources among bilateral customers.

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106 Such trades would be worthwhile to consumers because the constrained-off generators would have marginal costs below the unconstrained price charged to all consumers. Hence, any consumer could do better than the unconstrained price through a contract with any constrained-off generator. Assuming that the PECO mechanism did not make constrained-off payments to these generators, the generators would also have an incentive to enter into bilateral contracts at prices between their marginal costs and the unconstrained price.

The instability of this kind of pricing mechanism is a primary reason why the U.K. system still does not allow physical bilateral contracts. Because the United Kingdom chose to postpone adoption of a system of locational pricing and instead base pricing on an unconstrained dispatch (an average-cost method that is similar to the PECO proposal), bilateral trading could not occur without risking significant costs shifts between traders and onto those participating in the pool's economic dispatch, shifts that would induce traders to leave the pool. Having failed to implement locational pricing to price energy efficiently in a constrained network, the United Kingdom prohibited direct physical bilateral trading in order to preserve the benefits of economic dispatch. As a result, all trading within the U.K. system must be done through the U.K. pool using the pool price as a reference. Ironically, it is this "mandatory" feature of the U.K. system that has been most criticized by those who wish to engage in direct bilateral contracting.

The solution to this problem is to use efficient locational pricing as a means to avoid cost shifts so that bilateral trading can be accommodated fairly without undermining the benefits of an economic dispatch. These benefits should be preserved not only because small consumers will tend to rely on the efficiency of that dispatch but also because the SO's dispatch is the most efficient tool to manage congestion in a non-discriminatory manner. That is the lesson the Norwegians learned from the U.K. experience. The Nordic system, which is often cited as the model for accommodating bilateral trading and a flexible pool, determines locational prices and charges and pays locational prices for spot energy purchases and sales (i.e., for balancing). This system accommodates bilateral trading without cost shifts.

The Supporting PJM Companies have learned the same lesson from the U.K. experience. Their proposal will accommodate bilateral trading without cost shifts. Moreover, their system will function fairly even if bilateral trading is extended to the retail sector, as may occur under various state programs. Moreover, it is worth noting that while the Nordic locational pricing system efficiently charges and pays for balancing, the Norwegians have not yet developed a system of tradable transmission rights to allow traders to fix in advance the price of transmission. The missing piece in the Nordic system is a set of transmission rights or contracts that traders can acquire to hedge their energy trades through credits of congestion payments. The Supporting PJM Companies' proposal includes this missing piece and is therefore a more complete system for supporting efficient bilateral trading.

D. Empirical Analysis

At my request the PJM IA staff has employed GE's MAPS-MWFLOW dispatch program to develop data that enable me to estimate customer prices and generator revenues under the pricing proposals of the Supporting PJM Companies and of PECO. This analysis is based on projected 1996 cost data from the 1995 Summer PJM production cost task force database (PJMPCTF), the MMG 1995 summer series powerflow and summer 1995 projections of 1996 loads. All generation has (unless otherwise noted) been assumed to be scheduled based on a cost based dispatch. The simulation has modeled generation and load in NYPP, ECAR, and VACAR as well as PJM, and it has been assumed that up to 3500 MW of economy energy are available from ECAR, at prices reflecting incremental running costs.

The initial analysis (Case I) estimates customer prices and generator revenues based on locational prices taking into account transmission congestion but not incremental losses.[107] It can be seen in Table 1 that estimated generator revenues total $4,390.4 million for the year 1996 and that the average cost of power to loads is $18.53/MWh before crediting of congestion rents and $18.09/MWh after crediting congestion rents of $105.8 million. It can further be seen that the average cost of power, before crediting congestion rents, ranged from $17.40/MWh for Penelec to $19.83/MWh for Delmarva Power & Light (DP&L).

I then used this same simulation to estimate generator revenues and customers prices under the PECO proposal, under the assumption that generators bid their costs (Case II). The generator bids used to estimate prices are therefore the same in Case I and Case II. Table 2 compares generator revenues and customer prices for Case I with two alternative estimates of generator revenues and customer costs under the PECO proposal.[108] These alternative estimates reflect alternative assumptions about how PECO might choose to calculate the hypothetical unconstrained price under its proposal. Several approaches to the calculation of such a hypothetical unconstrained price are at least possible.

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107 This is consistent with the interim pricing mechanism for PJM while the new EMS system is under development.

108 Both estimates, and those below, assume that the PECO proposal is made workable by including prohibitions on bilateral transactions.

I have first calculated the "unconstrained" price taking into account only those generators that are available in the MAPS-MWFLOW simulation based on the constrained dispatch (Case II). This approach is most consistent with my understanding of the PECO's proposed congestion pricing system. Since there is apparently no day-ahead market under the PECO proposal, the "unconstrained" price would presumably be calculated based on running-cost bids in the hour ahead market. Only units actually available for the real-time dispatch would have any reason to submit bids in the hour-ahead market under the PECO pricing system, and thus only the bids of these units could be utilized to calculate the hypothetical unconstrained price. To the extent that congestion were anticipated, generators that anticipated being "constrained-off" would not be available at the time of the real-time dispatch, would not submit bids, and would therefore not affect the calculation of the "unconstrained" price. The resulting estimates of generator revenues and customer prices are shown in Column 2 of Table 2. It can be seen that because the PECO proposal substantially raises the "unconstrained" price paid by load in "constrained-off" regions, the prices paid by load would be almost $.50/MWh higher under the PECO proposal than under the pricing mechanism proposed by the Supporting PJM Companies (net of transmission congestion credits), even if it is assumed that all generators bid their costs. This cost increase occurs because the prices paid by customers in the Baltimore Gas & Electric (BG&E), Met-Ed, Penelec and Pennsylvania Power & Light (PP&L) service territories under locational pricing would be substantially lower than the hypothetical "unconstrained" price they would pay under the PECO proposal.

It is noteworthy that the potential for this increase in customer costs under the PECO pricing proposal can also be seen in the estimates developed by PECO witnesses. Thus, it can be seen by comparing columns (h) and (I) of exhibits CEM-7 and CEM-8, attached to the Prepared Direct Testimony of Charles E. Mann August 1996, that the "unconstrained" prices estimated by PECO also exceed the "constrained-off" prices in Western PJM. PECO simply appears not to have tabulated the increase in energy costs to Western PJM customers under its proposal that is implied by its own price forecasts. Indeed, it is noteworthy that for the hours reported by Mr. Mann in Exhibits CEM-7 and CEM-8, the excess payments by load in Western PJM exceed the savings that PECO claims for Eastern loads from avoiding payment of congestion rents, see Tables 4 and 6 (or 5 and 7 using an alternative derivation). In addition, a substantial portion of the congestion rents that would be credited to transmission customers under the Supporting PJM Companies' proposal would be paid to generators under the PECO proposal. Thus, the analysis of the PECO witnesses also indicates that the PECO pricing system would raise customer prices, even if generators continued to bid their costs.

The customer price estimates in Column 2 of Table 2 assume that the SO would be able to maintain reliability on a congested system based on hour-ahead bidding under the PECO proposal at the same cost as it would based on day-ahead bidding and commitment under the Supporting PJM Companies' proposal. This assumption is unlikely to be satisfied as the additional time for planning that would be available under the Supporting PJM Companies' proposal would provide the SO with additional lower cost options for maintaining reliability in the face of congestion.

The inability of individual generators to accurately forecast transmission congestion would cause some generators to schedule themselves to operate that would not have been scheduled by the SO, thus raising generator costs and depressing the "unconstrained" price. Conversely, some generators that would have been scheduled day-ahead by the SO to operate as a result of anticipated transmission constraints would fail to forecast these transmission constraints and would therefore not be available or bid into the hour ahead dispatch under the PECO proposal, thereby raising generator costs and prices. On balance, it is not clear whether the inability of individual generators to forecast congestion as well as the SO would raise or lower the "unconstrained" price under the PECO proposal. This inefficiency would unambiguously raise generator costs, however, and these costs would ultimately have to be recovered through higher consumer prices.

The estimates labeled Case IIA in Table 2 are calculated under the alternative assumption that the hypothetical "unconstrained" price would be calculated by assuming that all of the generators available for scheduling (i.e., excluding only those that are unavailable because of forced or maintenance outages) would start up and actually provide bids even though they know they would not be included in the dispatch, based on their running costs. This is a very conservative assumption and not consistent with my understanding of how the PECO proposal would work, but the estimates are perhaps useful in putting a lower bound on the range of possible "unconstrained" prices. It can be seen in column 3, that the prices paid by loads would be lower under the PECO proposal than under locational marginal pricing if generators bid their costs, and if the unconstrained price were calculated based on bids by all units that could be available.

It is noteworthy that the "unconstrained" price is substantially higher if it is calculated taking into account only the generation that would actually need to be on line in the hour, than if it is calculated taking into account all generation that could have been scheduled to be available. This effect of the PECO pricing system might cause vertically integrated utilities in Western Pennsylvania to start up redundant generation and bid it into the pool, simply to keep the hypothetical "unconstrained" price paid by their loads from rising to such a high level. This is an additional source of inefficiency and excess costs that would be borne by consumers under the PECO proposal.

An important limitation of the Case II revenue and price estimates is that they assume that generators would bid their costs which, as noted above, would not be rational under the PECO pricing system. Case III corrects this, by assuming that "constrained-on" generators would bid the locational marginal price in the hour and thus would be paid the same price under the PECO pricing mechanism as under the locational pricing mechanism of the Supporting PJM Companies.[109] The "unconstrained" price is calculated based on the market based bids of "constrained-on" generators. Generator revenues and customers prices calculated for this case are shown in Table 3 and it can be seen that total generator revenues and load prices are higher in this case, due to the impact of market based bidding on the determination of the hypothetical "unconstrained" price. Thus, the price paid by loads would average nearly $2/MWh higher under the PECO proposal than under that of the Supporting PJM Companies, or almost $500 million per year.

As before, the figures in column 2 (Case III) reflect calculation of the "unconstrained" price based on the units available given the constrained unit commitment and I therefore view this estimate as providing the best forecast of prices under the PECO proposal. The estimates

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109 This change in bidding does not reflect market power as even firms with arbitrarily small market shares would find it profitable to bid the market price. Rather, the change in bidding strategy reflects a rational response to a SO pricing mechanism that in effect attempts to pay below-market prices.

in column 3 (Case 3A) assume that the unconstrained price is calculated without respect to the actual commitment, which probably does not reflect PECO's intent and would in any case likely be unworkable.

A striking side effect of the PECO pricing mechanism with market-based bidding is that the increase in the unconstrained price due to market-based bidding makes congestion appear very small. While actual congestion rents for this simulation are slightly over $100 million, they would appear to fall to only $2.3 million under the PECO proposal.[110] Thus, fully $4,879.4 million of the generator revenues in Case III are attributable to payments at the "unconstrained" price. The PECO pricing proposal masks congestion so that congestion would appear to be insignificant, even as congestion would be inflating prices by as much as $500 million.

It is again noteworthy that the impact of calculating the "unconstrained" price based only on the bids of generating units scheduled to operate in the constrained dispatch is substantial and would provide vertically integrated utilities in Western Pennsylvania with a powerful incentive to incur addition generation costs to prevent this wealth transfer.

In summary, with the exception of case IIA, the PECO congestion pricing proposal raises the costs to consumers and masks the true magnitude of transmission congestion. The one exceptional case depends on an unlikely combination of regulatory requirements that: (i) prohibit direct bilateral transactions; (ii) require all generators not available due to scheduled or forced outages to provide bids and be available to operate in each hourly market; and (iii) require all generators to indefinitely provide cost information, not market based bids, for use in the economic dispatch.[111] If this combination of regulations is the intent, then the PECO proposal would create the most mandatory off all possible pools, and thwart efforts to introduce competition into electricity generation.

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110 The PECO approach would appear to measure congestion (incorrectly) as only the constrained-on payments in excess of the "unconstrained" price.

111 Even with all of these regulatory restrictions the PECO proposal would almost certainly raise consumer costs in the long-run as generators would not continue to operate unless they recover their start-up costs and avoidable fixed operating costs as well as their running costs

Table 1 ESTIMATED REVENUES, COSTS AND PRICES, 1996	
	LMP Pricing **Case I**
Generator Revenues	
Total All Generators ($ MM)	4,390.4
Average Generator Price ($/MWh)	18.09
Load Costs and Prices (before congestion credits)	
Total Load Cost ($ MM)	4,496.2
Average Load Price ($/MWh)	18.53
Average AE Price ($/MWh)	18.9170
Average BG&E Price ($/MWh)	18.0614
Average DP&L Price ($/MWh)	19.8299
Average JCP&L Price ($/MWh)	18.8588
Average Met-Ed Price ($/MWh)	17.9502
Average PECO Price ($/MWh)	18.9440
Average PENELEC Price ($/MWh)	17.4049
Average Pepco Price ($/MWh)	18.4383
Average PSE&G Price ($/MWh)	17.9270
Average PP&L Price ($/MWh)	18.9918
Load Costs and Prices (after congestion credits)	
Total Load Cost ($ MM)	4,390.4
Average Load Price ($/MWh)	18.09

Table 2
ESTIMATED REVENUES, COSTS AND PRICES, 1996

	LMP Pricing	PECO Cost-Based Bidding	
	Case I	Case II[1]	Case IIA[2]
Generator Revenues			
Total All Generators ($ MM)	4,390.4	4,499.6	4,042.6
Average Generator Price ($/MWh)	18.09	18.54	16.66
Load Costs and Prices (before congestion credits)			
Total Load Cost ($ MM)	4,496.2	4,499.6	4,042.6
Average Load Price ($/MWh)	18.53	18.54	16.66
Average AE Price ($/MWh)	18.9170	18.54	16.66
Average BG&E Price ($/MWh)	18.0614	18.54	16.66
Average DP&L Price ($/MWh)	19.8299	18.54	16.66
Average JCP&L Price ($/MWh)	18.8588	18.54	16.66
Average Met-Ed Price ($/MWh)	17.9502	18.54	16.66
Average PECO Price ($/MWh)	18.9440	18.54	16.66
Average PENELEC Price ($/MWh)	17.4049	18.54	16.66
Average Pepco Price ($/MWh)	18.4383	18.54	16.66
Average PSE&G Price ($/MWh)	17.9270	18.54	16.66
Average PP&L Price ($/MWh)	18.9918	18.54	16.66
Load Costs and Prices (after congestion credits)			
Total Load Cost ($ MM)	4,390.4	4,499.6	4,042.6
Average Load Price ($/MWh)	18.09	18.54	16.66

1 Unconstrained price calculated based on units committed in the hour.
2 Unconstrained price calculated excluding only units unavailable due to outages.

Table 3
ESTIMATED REVENUES, COSTS AND PRICES, 1996

	LMP Pricing	PECO Market-Based Bidding	
	Case I	Case III[1]	Case IIIA[2]
Generator Revenues			
Total All Generators ($ MM)	4,390.4	4,881.7	4,600.4
Average Generator Price ($/MWh)	18.09	20.11	18.96
Load Costs and Prices (before congestion credits)			
Total Load Cost ($ MM)	4,496.2	4,881.7	4,600.4
Average Load Price ($/MWh)	18.53	20.11	18.96
Average AE Price ($/MWh)	18.9170	20.11	18.96
Average BG&E Price ($/MWh)	18.0614	20.11	18.96
Average DP&L Price ($/MWh)	19.8299	20.11	18.96
Average JCP&L Price ($/MWh)	18.8588	20.11	18.96
Average Met-Ed Price ($/MWh)	17.9502	20.11	18.96
Average PECO Price ($/MWh)	18.9440	20.11	18.96
Average PENELEC Price ($/MWh)	17.4049	20.11	18.96
Average Pepco Price ($/MWh)	18.4383	20.11	18.96
Average PSE&G Price ($/MWh)	17.9270	20.11	18.96
Average PP&L Price ($/MWh)	18.9918	20.11	18.96
Load Costs and Prices (after congestion credits)			
Total Load Cost ($ MM)	4,390.4	4,881.7	4,600.4
Average Load Price ($/MWh)	18.09	20.11	18.96

1 Unconstrained price calculated based on the market-based bids of units committed in the hour.
2 Unconstrained price calculated based on the market-based bids of all units except those unavailable due to outages.

Table 4

PECO Energy Projection of Generation Costs and Payments During Constrained Hours for 1996

Sample Date (1)	Sample Hour (2)	East Generation (3) (MW)	West Load (4) (MW)	Transmission East/West (5) (MW)	Prices: Bus E (6) ($/MWh)	Prices: Bus W (7) ($/MWh)	Prices: Unconstrained (8) ($/MWh)	Congestion Rental Payment (9) ($)	Changes Under PECO Proposal: Reduced Congestion Rental Credit (10) ($) [(8)-(7)]*(5)	Changes Under PECO Proposal: Reduced Generator Payment in East (11) ($)	Changes Under PECO Proposal: Additional Load Payment in West (12) ($) [(8)-(7)]*(4)	Changes Under PECO Proposal: Cost of Constraint (13) ($)	Change in Cost Under PECO System: Cost Based Bidding (14) ($) (12)-(11)+(13)+(10)	Change in Cost Under PECO System: Market Based Bidding (15) ($) (12)+(10)
2/28/96	hr 10	12,024	17,968	5,469	29.30	25.39	27.15	21,384	9,625	25,852	31,624	32	15,429	41,249
4/2/96	hr 10	8,599	15,054	6,722	23.77	21.75	23.76	13,578	13,511	86	30,259	2	43,686	43,770
5/6/96	hr 12	8,005	14,441	6,166	28.80	20.57	20.63	50,744	370	65,401	866	308	(63,857)	1,236
5/11/96	hr 18	6,620	11,423	5,183	19.77	16.15	17.03	18,764	4,561	18,138	10,052	286	(3,239)	14,613
5/23/96	hr 14	7,863	14,618	6,771	21.82	16.64	20.39	35,073	25,391	11,244	54,818	428	69,393	80,209
5/31/96	hr 10	10,951	16,223	5,610	30.33	23.49	25.26	38,373	9,930	55,522	28,715	300	(16,578)	38,644
6/17/96	hr 18	16,281	19,544	5,919	43.44	21.70	33.74	128,688	71,265	157,922	235,310	15,264	163,917	306,575
7/15/96	hr 22	14,158	18,353	6,272	46.70	21.85	28.60	155,858	42,336	256,260	123,883	19,149	(70,892)	166,219
8/1/96	hr 16	14,244	19,175	6,125	30.17	20.54	27.95	58,985	45,386	31,621	142,087	776	156,628	187,473
8/26/96	hr 16	8,362	14,395	7,192	34.67	20.43	23.09	102,419	19,131	96,828	38,291	4,407	(35,000)	57,421
11/4/96	hr 15	9,585	-14,337	5,038	30.84	23.94	27.19	34,764	16,374	34,986	46,595	1,946	29,929	62,969
11/11/96	hr 17	9,415	15,327	5,817	30.72	22.18	22.19	49,679	58	80,307	153	1,792	(78,304)	211
12/10/96	hr 11	12,668	17,805	4,517	30.13	27.36	28.41	12,513	4,743	21,788	18,695	219	1,869	23,438
12/30/96	hr 18	12,818	19,280	6,188	35.54	23.97	31.18	71,596	44,615	55,888	139,009	1,707	129,443	183,624
Average		10,828	16,282	5,928	31.14	21.85	25.47	56,601	21,950	65,132	64,311	3,330	24,459	86,261
Total		151,593	227,943	82,989				792,418	307,296	911,843	900,356	46,616	342,425	1,207,652

Sources:

(1) PECO Exhibit (CEM-7), column a

(2) PECO Exhibit (CEM-7), column a

(3) PECO Exhibit (CEM-7), column c

(4) PECO Exhibit (CEM-7), column d

(5) PECO Exhibit (CEM-7), column f

(6) PECO Exhibit (CEM-7), column g

(7) PECO Exhibit (CEM-7), column h

(8) PECO Exhibit (CEM-7), column i

(9) PECO Exhibit (CEM-7), column k; the formula is [(6)-(7)]*(5) but because of rounding errors the values were copied directly from the exhibit

(10) Based on Exhibit Data

(11) PECO Exhibit (CEM-7), column l; the formula is [(6)-(8)]*(3) but because of rounding errors the values were copied directly from the exhibit

(12) Based on Exhibit Data

(13) PECO Exhibit (CEM-7), column m

(14) Based on Exhibit Data

(15) Based on Exhibit Data

Table 5

PECO Energy Projection of Generation Costs and Payments During Constrained Hours for 1996

Sample Date (1)	Sample Hour (2)	East Generation (3) (MW)	West Generation (4) (MW)	Prices: Bus E (5) ($/MWh)	Prices: Bus W (6) ($/MWh)	Prices: Unconstrained (7) ($/MWh)	Cost of Constraint (8) ($)	Payments to Generators: PECO (9) ($) [(3)+(4)]*(7)+(8)	Payments to Generators: PJM Supporting Companies (10) ($) [(3)*(5)]+[(4)*(6)]	Payments to Generators: Difference (11) ($) (9)-(10)
2/28/96	hr 10	12,024	23,480	29.30	25.39	27.15	32	963,966	948,460	15,505
4/2/96	hr 10	8,599	21,776	23.77	21.75	23.76	2	721,712	678,026	43,686
5/6/96	hr 12	8,005	20,645	28.80	20.57	20.63	308	591,358	655,212	(63,854)
5/11/96	hr 18	6,620	16,625	19.77	16.15	17.03	286	396,148	399,371	(3,223)
5/23/96	hr 14	7,863	21,389	21.82	16.64	20.39	428	596,876	527,484	69,393
5/31/96	hr 10	10,951	21,877	30.33	23.49	25.26	300	829,535	846,035	(16,499)
6/17/96	hr 18	16,281	25,487	43.44	21.70	33.74	15,264	1,424,516	1,260,315	164,202
7/15/96	hr 22	14,158	24,625	46.70	21.85	28.60	19,149	1,128,343	1,199,235	(70,892)
8/1/96	hr 16	14,244	25,308	30.17	20.54	27.95	776	1,106,254	949,568	156,687
8/26/96	hr 16	8,362	21,635	34.67	20.43	23.09	4,407	697,038	731,914	(34,876)
11/4/96	hr 15	9,585	19,391	30.84	23.94	27.19	1,946	789,803	759,822	29,982
11/11/96	hr 17	9,415	21,211	30.72	22.18	22.19	1,792	681,383	759,689	(78,306)
12/10/96	hr 11	12,668	22,333	30.13	27.36	28.41	219	994,597	992,718	1,880
12/30/96	hr 18	12,818	25,575	35.54	23.97	31.18	1,707	1,198,801	1,068,584	130,216
Average		10,828	22,240	31.14	21.85	25.47	3,330	865,738	841,174	24,564
Total		151,593	311,357				46,616	12,120,331	11,776,431	343,899

Sources.
(1) PECO Exhibit (CEM-7), column a
(2) PECO Exhibit (CEM-7), column a
(3) PECO Exhibit (CEM-7), column c
(4) PECO Exhibit (CEM-7), column e
(5) PECO Exhibit (CEM-7), column g
(6) PECO Exhibit (CEM-7), column h
(7) PECO Exhibit (CEM-7), column i
(8) PECO Exhibit (CEM-7), column m
(9) Based on Exhibit Data
(10) Based on Exhibit Data
(11) Difference of (9) and (10)

Table 6

PECO Energy Projection of Generation Costs and Payments During Constrained Hours for 2000

Sample Date (1)	Sample Hour (2)	East Generation (3) (MW)	West Load (4) (MW)	Transmission East/West (5) (MW)	Prices: Bus E (6) ($/MWh)	Prices: Bus W (7) ($/MWh)	Prices: Unconstrained (8) ($/MWh)	Congestion Rental Payment (9) ($)	Changes Under PECO Proposal: Reduced Congestion Rental Credit (10) ($) [(8)-(7)]*(5)	Changes Under PECO Proposal: Reduced Generator Payment in East (11) ($)	Changes Under PECO Proposal: Additional Load Payment in West (12) ($) [(8)-(7)]*(4)	Changes Under PECO Proposal: Cost of Constraint (13) ($)	Change in Cost Under PECO System: Cost Based Bidding (14) ($) (12)-(11)+(13)+(10)	Change in Cost Under PECO System: Market Based Bidding (15) ($) (12)+(10)
2/23/00	hr 19	13,037	19,043	5,421	35.58	33.48	33.49	11,385	54	27,247	190	190	(26,812)	245
4/17/00	hr 15	9,694	15,239	5,771	26.42	21.65	22.68	27,528	5,944	36,255	15,696	982	(13,633)	21,640
4/21/00	hr 13	10,446	16,266	5,694	39.80	22.93	25.42	96,057	14,178	150,219	40,502	5,821	(89,718)	54,680
5/15/00	hr 15	9,930	16,204	5,557	26.60	22.84	24.73	20,894	10,503	18,569	30,626	508	23,067	41,128
5/26/00	hr 24	10,147	14,238	5,797	26.53	21.62	23.17	28,465	8,985	34,093	22,069	1,638	(1,401)	31,054
6/12/00	hr 24	10,948	15,568	5,551	35.23	21.25	25.79	77,608	25,202	103,345	70,679	6,449	(1,016)	95,880
6/23/00	hr 21	8,595	15,227	5,594	23.30	16.61	21.88	37,421	29,480	12,204	80,246	316	97,839	109,727
7/3/00	hr 14	12,386	17,253	5,180	51.83	26.95	38.49	128,873	59,777	165,230	199,100	2,619	96,266	258,877
7/15/00	hr 22	10,779	15,310	5,692	26.66	22.03	22.56	26,354	3,017	44,194	8,114	2,708	(30,355)	11,131
7/24/00	hr 15	15,636	20,581	6,045	36.07	30.66	33.55	32,702	17,470	39,402	59,479	358	37,905	76,949
8/6/00	hr 2	8,708	13,526	6,521	25.10	21.91	23.28	20,801	8,934	15,849	18,531	755	12,370	27,464
8/14/00	hr 5	8,229	13,274	6,498	23.40	20.04	20.04	21,833	-	27,650	-	512	(27,138)	-
8/22/00	hr 11	10,131	16,148	6,343	26.81	23.02	23.40	24,041	2,410	34,548	6,136	472	(25,529)	8,547
9/2/00	hr 20	7,745	12,994	5,704	22.71	20.10	21.31	14,888	6,902	10,843	15,723	478	12,260	22,625
Average		10,458	15,777	5,812	30.43	23.22	25.70	40,632	13,775	51,403	40,507	1,700	4,579	54,282
Total		146,411	220,871	81,368				568,850	192,856	719,648	567,091	23,806	64,105	759,947

Sources:
(1) PECO Exhibit (CEM-8), column a
(2) PECO Exhibit (CEM-8), column a
(3) PECO Exhibit (CEM-8), column c
(4) PECO Exhibit (CEM-8), column d
(5) PECO Exhibit (CEM-8), column f
(6) PECO Exhibit (CEM-8), column g
(7) PECO Exhibit (CEM-8), column h
(8) PECO Exhibit (CEM-8), column i
(9) PECO Exhibit (CEM-8), column k; the formula is [(6)-(7)]*(5) but because of rounding errors the values were copied directly from the exhibit
(10) Based on Exhibit Data
(11) PECO Exhibit (CEM-8), column l; the formula is [(6)-(8)]*(3) but because of rounding errors the values were copied directly from the exhibit
(12) Based on Exhibit Data
(13) PECO Exhibit (CEM-8), column m
(14) Based on Exhibit Data
(15) Based on Exhibit Data

Table 7

PECO Energy Projection of Generation Costs and Payments During Constrained Hours for 2000

Sample Date (1)	Sample Hour (2)	East Generation (3) (MW)	West Generation (4) (MW)	Prices: Bus E (5) ($/MWh)	Prices: Bus W (6) ($/MWh)	Prices: Unconstrained (7) ($/MWh)	Cost of Constraint (8) ($)	Payments to Generators: PECO (9) ($) [(3)+(4)]*(7)+(8)	Payments to Generators: PJM Supporting Companies (10) ($) [(3)*(5)]+[(4)*(6)]	Payments to Generators: Difference (11) ($) (9)-(10)
2/23/00	hr 19	13,037	24,464	35.58	33.48	33.49	190	1,256,098	1,282,911	(26,813)
4/17/00	hr 15	9,694	21,010	26.42	21.65	22.68	982	697,349	710,982	(13,633)
4/21/00	hr 13	10,446	21,960	39.80	22.93	25.42	5,821	829,582	919,294	(89,712)
5/15/00	hr 15	9,930	21,761	26.60	22.84	24.73	508	784,226	761,159	23,067
5/26/00	hr 24	10,147	20,035	26.53	21.62	23.17	1,638	700,955	702,357	(1,402)
6/12/00	hr 24	10,948	21,119	35.23	21.25	25.79	6,449	833,457	834,477	(1,020)
6/23/00	hr 21	8,595	20,821	23.30	16.61	21.88	316	643,938	546,100	97,838
7/3/00	hr 14	12,386	22,433	51.83	26.95	38.49	2,619	1,342,802	1,246,536	96,267
7/15/00	hr 22	10,779	21,002	26.66	22.03	22.56	2,708	719,687	750,042	(30,355)
7/24/00	hr 15	15,636	26,626	36.07	30.66	33.55	358	1,418,248	1,380,344	37,904
8/6/00	hr 2	8,708	20,047	25.10	21.91	23.28	755	670,171	657,801	12,371
8/14/00	hr 5	8,229	19,771	23.40	20.04	20.04	512	561,632	588,769	(27,137)
8/22/00	hr 11	10,131	22,491	26.81	23.02	23.40	472	763,827	789,355	(25,528)
9/2/00	hr 20	7,745	18,698	22.71	20.10	21.31	478	563,978	551,719	12,260
Average		10,458	21,588	30.43	23.22	25.70	1,700	841,854	837,275	4,579
Total		146,411	302,238				23,806	11,785,951	11,721,845	64,106

Sources:
(1) PECO Exhibit (CEM-7), column a
(2) PECO Exhibit (CEM-7), column a
(3) PECO Exhibit (CEM-7), column c
(4) PECO Exhibit (CEM-7), column e
(5) PECO Exhibit (CEM-7), column g
(6) PECO Exhibit (CEM-7), column h
(7) PECO Exhibit (CEM-7), column i
(8) PECO Exhibit (CEM-7), column m
(9) Based on Exhibit Data
(10) Based on Exhibit Data
(11) Difference of (9) and (10)