REPORT ON THE PROPOSAL TO RESTRUCTURE THE NEW YORK ELECTRICITY MARKET

prepared by

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on behalf of

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Consolidated Edison Company of New York, Inc.
Long Island Lighting Company
New York State Electric & Gas Corporation
Niagara Mohawk Power Corporation
Orange and Rockland Utilities, Inc.
Rochester Gas and Electric Corporation
Power Authority of the State of New York

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Affidavit of William W. Hogan[1]
in Support of
Proposal to Restructure the New York Electricity Market

The eight members of the New York Power Pool (Transmission Providers) are proposing to the Federal Energy Regulatory Commission (Commission) a restructured transmission and energy trading arrangement for the State of New York.[2] The proposal calls for the creation of a new market structure, new institutions and governance arrangements, open access to the statewide transmission system, and new pricing rules for both energy and transmission.

The purpose of the present report is to comment on the implications of the Proposal for economic efficiency and reliability and also to indicate why I believe it to be consistent with the FERC policy of promoting competition in bulk power markets, as enunciated in its Order 888. My comments address the structural aspects of the Proposal that support a competitive generation market. I have not evaluated how the new institutions would be governed under the Proposal. These governance issues are addressed in a separate supporting affidavit from Dr. Larry E. Ruff.

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2 The Transmission Providers are Central Hudson Gas & Electric Corporation Consolidated Edison Company of New York, Inc., Long Island Lighting Company, New York State Electric & Gas Corporation, Niagara Mohawk Power Corporation, Orange and Rockland Utilities, Inc., Rochester Gas & Electric Corporation, and the Power Authority of the State of New York.

Likewise, I do not address market power issues here. Each New York utility seeking market-based pricing authority from the Commission plans to submit market analyses at a later time.

This report focuses on the proposed wholesale electricity market structure and the corresponding system of locational pricing for energy and congestion pricing of transmission. The first part of the report is a summary that describes the Proposal and gives my conclusions. Section I describes the so-called Locational-Based Marginal Pricing (LBMP) system, including the day-ahead scheduling market, the hourly balancing market, transmission pricing, and Transmission Congestion Contracts (TCCs). Section II indicates why the Proposal will maintain, and likely improve, the reliable operation of the New York power system. Section III discusses how the Proposal promotes economic efficiency and supports the development of a competitive generation market. Section IV shows how the Proposal accommodates flexible trading. Section V indicates why the Proposal is consistent with the Commission's objectives of comparability and efficiency, and why the Proposal is not an inadmissible form of "and" pricing. Section VI addresses certain other issues, while the final section recasts my conclusions.

EXECUTIVE SUMMARY

The Proposal of the Transmission Providers is designed to establish a competitive wholesale electricity market and create the institutions and rules necessary to make that market reliable, efficient and commercially flexible. The Proposal will facilitate a competitive market for electricity by providing all eligible market participants open, non-discriminatory access to the transmission system, meeting the standards set by the Commission, and by providing an open, voluntary spot market in which buyers and sellers can buy and sell energy and transmission at market-based prices. In addition, the Proposal will accommodate bilateral trades between buyers and sellers and provide transmission services on a comparable basis at economically efficient prices, while ensuring that such trades do not shift costs onto other system users and consumers. At the same time, the Proposal will preserve system reliability through a combination of market and other mechanisms designed to meet the particular reliability needs of New York.

The Transmission Providers' Proposal will take advantage of the existing structure of the New York Power Pool (NYPP) and its least-cost or economic dispatch, but will turn over operational control of this dispatch and transmission operations to a newly-created "Independent System Operator" (ISO). The ISO will function as an unbiased system coordinator without a commercial interest in the market, operating the system on behalf of the entire market, while maintaining system reliability and administering an Open Access Tariff. The Transmission Providers have designed the ISO to meet the principles for an ISO articulated by the Commission in Order No. 888, as well as that Order's requirements for a "conforming" Open Access Tariff.[3] Indeed, with its efficient pricing mechanisms for energy and transmission, the Proposal goes beyond Order No. 888's mandate to provide comparable open access to all transmission users.

The Proposal will also create a New York Power Exchange (NYPE), which will provide, in conjunction with other power exchanges (PEs), an aggregating mechanism through which buyers and sellers can submit price and quantity bids for energy and ancillary services to the ISO

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3 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").

and arrange for settlement payments based on the prices and dispatch determined by the ISO. The energy bids will include start-up and minimum generation costs. The ISO will use these voluntary offers to coordinate a day-ahead scheduling market and real-time balancing market for energy, transmission and some ancillary services. Any power supplier may voluntarily participate in the day-ahead market and submit voluntary price and quantity bids to the ISO through the NYPE or any other PE, specifying the minimum prices the supplier is willing to accept to operate at output ranges the supplier specifies. Those preferring to use inflexible or partly flexible bilateral transactions also may provide their schedules for the day-ahead market. Using these voluntary offers, as well as any "demand bids" associated with flexible loads, the ISO will determine the security-constrained economic day-ahead schedule and dispatch and day-ahead prices. In this way, suppliers, load-serving entities (LSEs) and transmission customers will be able to lock in prices and dispatch commitments in the day-ahead markets. In the subsequent hourly balancing market any participant may submit voluntary price and quantity offers to the ISO, which will be the basis for the final security-constrained least-cost dispatch and the calculation of balancing market prices.

Through these markets, any supplier will have equal and open access to the transmission grid and to all loads served at the wholesale level through the ISO's dispatch. Both the NYPE and the ISO's bidding and dispatch rules will apply without discrimination to participants regardless of ownership, affiliation or type of transaction. The flexibility to move freely between the ISO-coordinated markets and the bilateral market is consistent with the "flexible poolco" model endorsed by the New York Public Service Commission in its Competitive Opportunities Order.

This will also allow the electricity market to evolve over time and will simplify participation in the market, especially for smaller, less diversified suppliers and customers.

A key feature of the New York Proposal is the mechanism by which the market will set prices for both energy and transmission. The Proposal will convert the existing NYPP economy energy market from a shared-savings economic dispatch among NYPP members to structure that would support a competitive, bid-based market for energy and transmission usage that will determine market-clearing prices at each location in the system. The ISO provides central coordination for two markets -- a day-ahead scheduling market and an hourly balancing market, each with a separate set of locational prices. These locational market-clearing prices will provide the basis for the ISO's settlements with all suppliers, loads and transmission customers who participate in either market. This system of locational-based marginal prices (LBMP) is efficient and would support a competitive wholesale electricity market. It is efficient because the prices at each location reflect the marginal cost of supplying additional load (as reflected in the bids) at each location. Such a price is no higher than needed to attract additional supply and is no lower than needed to ration the demand. Any other price would lead to either excess supply or demand, and would create market distortions and inefficiencies. The Proposal would support a competitive wholesale market because it is based on voluntary participation and open access to the grid. Any commercial arrangement between a supplier and a customer could be implemented as any combination of inflexible bilateral schedules or flexible bids that will be settled at the LBMPs in the centrally-coordinated markets. The participants' preferences as expressed in their bids determine the market results and the use of the system. Energy traders can compete with one another in any manner they choose. No trading restrictions are imposed, other than the ISO must be informed of all day-ahead schedules and hourly use. This scheduling and spot market coordination role of the ISO is the minimum required in order to ensure reliability and balance the market in the face of the unavoidable and complex interactions in the transmission network.

Reliance on locational market-clearing prices will allow transmission use to be priced on a comparable basis for all market participants at all times, including when the transmission system is constrained or congested. When a transmission constraint binds, the ISO's dispatch adjustments will result in different market-clearing prices at different locations that are affected by the constraint. These market-clearing prices will apply to purchases and sales made through the PEs. The difference in locational prices between the withdrawal and injection locations will be the price of transmission usage between these locations. This transmission usage charge has two parts -- one based on the congestion costs between the two locations and the other reflecting the difference in the marginal cost of losses between the two locations. The congestion cost portion of this transmission price reflects the opportunity cost of trade limitations created by transmission constraints between any two locations.

Suppliers and customers relying on the ISO-coordinated day-ahead and balancing markets will pay for transmission congestion and marginal losses implicitly through their respective locational prices for purchases and sales. Bilateral market participants who do not participate in the ISO-coordinated markets will explicitly pay the same price for transmission usage computed as the difference in the LBMP between the withdrawal and injection locations. Hence, bilateral traders and NYPE participants will be treated comparably, and there will be no cost shifting between market participants. Because of this consistent and comparable pricing, the system can operate with no arbitrary restrictions on bilateral transactions and no arbitrary restriction on participation in the bid-based economic dispatch. Thus, choices can be determined by the preferences of the participants in response to the efficient signals and incentives provided by the locational prices.[4]

The Proposal also provides for a type of transmission reservation in the form of a financial obligation, called a transmission congestion contract (TCC). These TCCs will be financially equivalent to, but more flexible than, point-to-point firm transmission service and will provide a means by which transmission users can fix in advance the price of transmission use between two locations.[5] Transmission users who acquire a TCC will be entitled to any congestion rentals from the ISO in the event that transmission constraints create differences in the corresponding locational prices. If a transmission user's actual use of the system matches its TCC, then the credit will exactly offset any transmission congestion charge resulting from the constraint, thus providing the user with a perfect hedge against the uncertainty of congestion charges. If the use does not exactly match the TCC, the user will either be credited or billed for the difference. TCCs work the same and perform the same hedging role for either bilateral transactions or arrangements made in the centrally-coordinated markets.

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[4] Likewise, the Proposal treats all loads comparably. LSEs serving retail load and wholesale LSEs (munis and Coops) pay a transmission service charge plus a congestion component that is computed the same for each.

[5] A TCC is a contract between the ISO and any eligible party. A TCC obligation specifies a receiving location, a delivery location and a quantity of power in MWs. When the LBMP at the delivery location exceeds that at the receipt location, the contract obligates the ISO to pay the TCC holder the congestion cost computed as the contract quantity in megawatts multiplied by the price difference between the receipt and delivery locations. When the locational prices are reversed, the contract obligates the TCC holder to pay the ISO the corresponding congestion cost.,

The TCCs may be obtained in several ways, including an auction to be held every six months during the initial period of operation. These TCCs can be resold and so will be available in the secondary market. As financial obligations, TCCs will not permanently allocate transmission capacity. Instead, the transmission usage associated with the TCCs will be traded, in effect, on an hour-by-hour basis as a result of the ISO's unit commitment and dispatch in the day-ahead market. This automatic trading system provides substantial flexibility for transmission customers, because it allows them either to schedule their use of the system and be fully hedged against congestion charges (if the use matches the TCC), providing the operational equivalent of truly firm service, or to vary their use and be compensated through the congestion costs charged to others that are scheduled by the ISO. The Proposal is thus a practical method that is fully consistent with the Commission's principles and objectives for flexible, tradable transmission rights, as set forth in the provisions of the Capacity Reservation Tariff Notice of Proposed Rulemaking (CRT NOPR).[6]

The Proposal also enhances the ability of the ISO to maintain the reliability standards in New York in a competitive environment. The ISO must comply with all applicable standards set by the proposed New York State Reliability Council (NYSRC) to meet the particular reliability needs in New York. It is expected that the NYSRC criteria will encompass those of higher-level organizations, such as the North American Electric Reliability Council (NERC) and the Northeast Power Coordinating Council (NPCC). The ISO will develop the procedures necessary to operate the system within these standards and criteria. In addition, the Proposal ensures that reliability

6 Capacity Reservations Transmission Tariff Notice of Proposed Rulemaking 75 FERC ¶61,079 (1996) (hereafter "CRT NOPR").

will be maintained through certain provisions pertaining to the day-ahead market and the installed capacity requirements, as discussed later. In particular, an essential function of the ISO 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 and scheduling process, as well as in real time, the ISO will examine all scheduled and actual flows on the grid and will adjust generation and loads subject to the ISO's dispatch as needed to maintain frequency, balance loads and resources and honor all reliability constraints. An important characteristic of the Proposal is that all market participants will be allowed to bid into the balancing market and all bids will be passed to and acted upon by the ISO, which will both enhance reliability and also allow constraints to be resolved economically and without discrimination. Market participants will have the maximum degree of commercial flexibility that would be possible without cost-shifting and consistent with the limits of reliability and the unavoidable necessity to address the interactions in the transmission network.

The ISO also will establish an annual installed capacity requirement for LSEs based on standards developed by NERC, NPCC and the NYSRC. This requirement is intended to ensure long-term reliability by requiring sufficient resources to be secured in advance to meet projected peak loads and operating reserve requirements.

Finally, the creation of an ISO and separate PEs may lead to confusion when compared to some other proposals that have been discussed elsewhere or may be advanced in New York. It is absolutely essential to the Proposal that the ISO is administering the spot market, in the form of the day-ahead scheduling market and the real-time balancing market. The several PEs may perform many functions, including aggregating bids and passing the information to the ISO. But in the end, the ISO is the only entity that would have the information needed to recognize and accommodate the complex network interactions and balance the system in an economically efficient way consistent with the preferences of the participants and the reliability requirements of the system. *For fundamental reasons, the separate PEs cannot perform this function.* In fact, to provide a simple, transparent competitive market that is comparable and easy to use for all participants, large and small, it is essential that the ISO administer the spot market according to the principles of a bid-based economic dispatch and that anyone be free to participate in this market. The existence of such an ISO to support an efficient, competitive market will reduce the opportunities for some to profit from any other system that might look simple on the surface but would in reality be unnecessarily complex, opaque and inefficient. Therefore, the idea of an ISO administering an open spot market has been and will continue to be subject to relentless attack, long on slogans and short on analysis. No amount of rhetoric or obfuscation, rampant elsewhere on this point, should confuse the Commission or detract from its ability to do what is right and good public policy.

I. DESCRIPTION OF THE TRANSMISSION PROVIDERS' PROPOSAL[7]

A. Locational-Based Marginal Pricing (LBMP)

Energy Pricing Overview

On a constrained transmission grid, such as the one in New York, the marginal cost of electrical energy to meet load varies by location. The Proposal of the Transmission Providers recognizes the inescapable fact that the power supplied to an interconnected grid flows in response to the laws of physics, regardless of the contractual arrangements among the users of the grid. 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-strict-merit order, and the price to serve load in the constrained area will consequently increase, while the price in unconstrained areas will decrease.[8]

The Transmission Providers' 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

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7 This description reflects my understanding of the Transmission Providers' Proposal; however, the actual January 31, 1997 filings are the controlling documents.

8 This describes how prices an respond in simple constrained situations such as a load pocket with limited import capability. In other circumstances, the result can be more complex. Due to network interactions, even a single transmission constraint can produce a different price at every location.

lower-cost generation must be curtailed because of the constraints. Consequently, the Transmission Providers' Proposal determines not only marginal prices, but *locational* marginal prices. Under the Proposal, the ISO will publish hourly prices based on the average of the marginal cost of supplying electricity at each generation bus and load zone in the NYPP control area every five minutes. Thus, the Proposal extends the efficiency benefits of marginal cost pricing to the demands of electricity markets by taking into account the fact that the marginal cost of serving load varies by location and over time.

Locational prices arise naturally from a security-constrained economic dispatch and provide an efficient mechanism for pricing transmission usage. Under locational pricing the short-run opportunity cost of transmission between any two locations can be determined from the corresponding difference in LBMPs.[9] The system thus provides an internally consistent pricing structure for energy and transmission. The principles underlying locational spot pricing have been widely discussed and are well defined.[10] Under the Proposal, locational spot prices will be determined by the ISO's bid-based economic dispatch of loads and generation across the

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9 The opportunity cost or congestion cost is the LBMP difference adjusted for marginal losses.

10 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).

transmission grid.[11] Prices are based on the actual dispatch, and there is no computational difficulty in determining the price at every location in the real systems. The actual schedules and 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. Appendix A, Section 1, provides detailed examples that illustrate the calculation of LBMPs.

All suppliers in the centrally coordinated energy market will be paid the applicable locational price for the power they produce and all buyers in this market will pay the applicable locational price for power consumed. Locational prices paid to suppliers will be calculated at the locations where the generators inject energy into the grid. Prices paid by LSEs will be calculated for the zones from which the LSEs withdraw energy from the grid. These zonal prices for load will be calculated as the load-weighted average of locational prices within each zone. An initial set of zones will be defined to be consistent with major transmission interface configurations.

There is no distinction between LSEs and other market participants, and there is no distinction between those who use the spot market coordinated by the ISO and those who use

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11 Data describing the real-time dispatch will determine the locational marginal prices. At each substation bus in the NYPP bulk power transmission system where electric power is delivered by sellers and/or receipt is taken by buyers, deliveries and receipts will be measured (or in some cases estimated) and the measurement data will be transmitted to ISO computers. Actual power flows on the bulk power transmission facilities will be similarly measured or, in some cases, estimated. At 5-minute intervals, a Security Constrained Dispatch (SDC) program similar to that currently used by system operators to operate the bulk power system will be used to calculate locational prices. The SCD program also will have as an input the solved power flow; relevant bid data for all loads and all resources making deliveries to the ISO operated spot power market; and identification of binding transmission constraints. This information will be used to calculate the marginal cost of electricity at each substation in the ISO bulk power transmission grid in each 5-minute interval.

self-scheduled or bilateral transactions. Access to and payment for the services provided by the ISO will be the same for all participants.

The central energy market is entirely voluntary. Buyers and sellers are not required to bid into the centrally coordinated market. LSEs, for example, can arrange two-party ("bilateral") transactions for any portion of their needs so long as they provide their schedules at the appropriate time to the ISO for either the day-ahead market (through a PE) or the hourly-balancing market and pay for transmission based on the transmission usage charges determined by the ISO's dispatch. The energy price in such two-party transactions will be strictly a matter of negotiation between the buyer and seller. The pricing system thus can accommodate transactions that are perceived by buyers to have non-market value or benefit, such as the purchase of energy from "green" or environmentally friendly resources.

The ISO will coordinate the market in two phases, a day-ahead scheduling market and a real-time balancing market. These markets will work together to provide the ISO with the tools it will need to maintain reliability, but with minimal reliance on arbitrary administrative penalties or arbitrary rules restricting commercial flexibility. This combination of a day-ahead scheduling and real-time balancing market is referred to as the "two-settlement" system.

Day-Ahead Market for Unit Commitment and Dispatch

A day-ahead scheduling process or market will be established to enable the ISO to ensure that sufficient generating capacity is committed so that the system will operate reliably in real-time. LSEs, generators and transmission customers will all be permitted to participate in this market. In brief, a two-settlement system means that there are two points in time (day-ahead and real-time balancing) in which:

- The participants in the short-term energy and transmission market make bids or provide schedules to the ISO (through their PEs in the day-ahead market).
- The ISO uses the proposed schedules and bids to dispatch the system and ensure its reliable operation.
- The ISO determines LBMPs.
- The ISO arranges financial settlements with the PEs based on LBMPs.[12]

All LSEs will be required to submit load forecasts to the ISO through a PE on a day-ahead basis. These forecasts will be used by the ISO in its assessment of reliability but will not create any financial commitment on the part of the PE or LSE or any financial obligation by the ISO to the PE or LSE. The LSEs will have the option to schedule generation themselves to meet their needs or to submit demand bids (dispatchable or not) to the ISO (through a PE) and let the ISO commit units to meet their load. LSEs may, at their option, purchase all or part of their energy requirements in the day-ahead market, either through bilateral transactions or through participation in the centralized market coordinated by the ISO, or the LSE can choose to purchase these requirements in the real-time balancing market. Thus, LSEs can choose what portion of their expected load they wish to schedule day ahead through the ISO and which portion they wish to defer scheduling until the balancing market.

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12 Section 2 of Appendix A contains examples that illustrate the two-settlement system.

All generators that wish to participate in the day-ahead scheduling market will be able to submit bids consisting of their start-up, minimum generation and incremental running costs. These bids will be submitted through the generator's PE during the day before the actual dispatch and may cover any or all of the 24 hourly trading periods. There is no obligation by generators to participate in the day-ahead market but all generators have the option to do so if they wish to lock in a day-ahead price, concurrently with scheduling gas or committing their unit.[13]

Similarly, transmission customers wishing to schedule transmission in the day-ahead market will inform the ISO of bilateral transmission schedules (through their PE) and may, at their option, provide the ISO with incremental and decremental bids for deviations from these schedules. Although there is no obligation on the part of transmission customers to inform the ISO of their transactions in the day-ahead market, it is expected to be in the customer's interest to provide such information, especially if the transmission grid is constrained. In such a circumstance, the day-ahead scheduling process will provide the ISO with more time to adjust generation to take account of transmission constraints and thus reduce the transmission usage charges paid by the transmission customer. Thus, for example, if a particular bilateral transaction would, in conjunction with other scheduled supply and demand, result in a voltage problem at a particular location, then the least-cost method of accommodating that transaction might be to start a generator to provide reactive power. If the ISO is not aware of the bilateral transaction until 90 minutes before the real-time market, it could be too late to start the generator to provide reactive power. Instead, other higher-cost solutions, resulting in a higher transmission usage

13 Suppliers must submit either an inflexible schedule or a bid into the day-ahead market for any capacity that they have obligated in the installed capacity market.

charge, might be required to maintain reliability while accommodating the bilateral transaction. By scheduling transmission usage a day ahead, the transmission customer provides the ISO with greater flexibility to dispatch generation to accommodate the transaction, thereby reducing the expected cost of transmission for transmission customers.

Based on its assessment of feasible transmission flows, proposed bilateral transactions, generator and load bids provided by the PEs, and load forecasts provided by LSEs for reliability purposes, the ISO will develop a bid-based economic unit commitment and energy schedule.[14] The unit commitment process will simultaneously optimize the schedule for bid-in energy, regulation and operating reserves, subject to the commitment of sufficient capacity to meet the reliability requirements for the forecasted load over the following 24-hour period. This schedule will also be used by the ISO to determine the day-ahead prices that will be used by the ISO to price energy, transmission and TCCs in the day-ahead market, as described below. The ISO will publish the resulting LBMPs. The ISO will also provide all suppliers, loads and transmission customers with their accepted schedules, which will constitute financial commitments by and to the ISO. The day-ahead schedules are settled at the day-ahead LBMPs. These schedules become dispatch commitments for the hourly balancing market, as described below.

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14 Thus, in the case of fixed energy and transmission demands, the ISO will schedule generation and ancillary services so as to minimize the total cost (as bid) of accommodating these energy and transmission demands. That is, the ISO would not schedule a unit to meet load unless the alternative ways of meeting load would raise the total cost of meeting load (total cost includes running costs, start-up costs and minimum load costs). If some of the demand or transmission schedules were price sensitive, the ISO would maximize producer and consumer surplus, which means that the ISO would not schedule generation to meet load (or provide transmission) if the cost of the incremental generation required to meet that load (or provide transmission services) exceeded the value of that load (or transmission) as bid by the customer.

It is possible that there will be situations in which the total payments to a supplier for energy and ancillary services at the market prices determined by the ISO's day-ahead dispatch will not be sufficient to cover the bid in start-up, minimum-load and running cost bids of the supplier. In this case, the supplier would be compensated for its total bid-in costs that are in excess of its market revenues (from LBMPs), which in turn will be recovered from all loads and transmission customers in the real-time balancing market through an uplift charge.

Hourly Balancing Market for Energy

Suppliers, dispatchable loads and transmission customers that wish to participate in the hourly balancing market must submit energy-only bids or fixed schedules up to 90 minutes before the actual dispatch.[15] (This includes all bilateral customers who wish to make unscheduled transactions.) The ISO will use the hourly energy bids to operate the power system using a 5-minute Security Constrained Dispatch program. This dispatch of the system by the ISO will determine locational prices for each 5-minute dispatch interval, which are the settlement prices for the balancing market. Generator injections, LSE withdrawals and transmission injections and withdrawals corresponding to the day-ahead schedule will not result in any further settlements (other than uplift). Energy imbalances relative to a party's day-ahead schedule will be settled based on the locational prices in this balancing market. Thus, flexible generators that are directed by the ISO to generate above their day-ahead schedule will be paid the balancing market price for

15 It is not necessary for non-dispatchable loads to bid into the real-time market as they will simply pay the real-time price for the power they consume.

these additional injections.[16] Similarly, a flexible generator that is directed by the ISO to back down below its day-ahead schedule will in effect buy power at the balancing market price to cover its day-ahead schedule.[17]

LSEs and customers will pay the balancing market price for withdrawals in excess of their day-ahead schedule. If their withdrawals are less than their day-ahead schedule they will sell the excess back at the balancing market price. Similarly, transmission customers whose real-time injections and withdrawals match their day-ahead schedule will pay no additional transmission usage charges but they will pay or receive the balancing market prices for any deviations from their day-ahead schedule.

Two-Settlement System

The combination of a day-ahead scheduling and market with a real-time or balancing market comprises the two-settlement system. Supply, demand and transmission scheduled day ahead will be settled based on the day-ahead prices, as will TCCs. Deviations from the day-ahead schedules will be settled based on real-time or balancing market prices. In effect, the ISO's acceptance of the day-ahead schedules will create a set of dispatch commitments for day-ahead market participants. These commitments both entitle the participants to inject and withdraw the amounts at the designated locations corresponding to the day-ahead schedules and obligate the participants

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16 This would be profitable for the generator as the locational price in the hour would equal or exceed the generator's bid price under locational pricing and economic dispatch.

17 This would be profitable for the generator as it would be backed down by the ISO only if the balancing market price were lower than the generator's running cost bid. In this situation, if the generator's running cost bid reflects its costs, it will be better off buying power at the balancing market price to cover its day-ahead schedule rather than operating itself since the balancing market price would be less than its cost of generating power.

to make those injections and withdrawals or, alternatively, to pay or receive payment at the locational prices for any deviations from those commitments.

Since TCCs will be settled at the day-ahead prices, TCCs also will be converted into dispatch commitments. Some of the day-ahead participants will hold TCCs and some may not. Thus, the total set of dispatch commitments that are made in the day-ahead market represent a reconfigured set of transmission reservations that differs from that inherent in the full set of outstanding TCCs. The two-settlement system effectively allows automatic trading of the longer-term financial transmission reservations (TCCs) so as to accommodate near-term (day-ahead) market conditions and preferences.

In the two-settlement system, a transmission customer with a TCC will pay only for marginal losses if it schedules a transaction corresponding to its TCC in the day-ahead market and makes injections and withdrawals corresponding to its dispatch commitments in real time. This customer would be charged the difference in locational prices for its transmission usage; all but the losses component of this charge would be offset by payments arising from its TCC ownership. The net cost of scheduling the transmission in the day-ahead market therefore would be the marginal cost of losses; it would owe nothing more for transmission.

B. Transmission Services

Transmission Pricing for Investment Cost Recovery -- TSC

Under the Proposal, transmission owners will recover their total transmission revenue requirement primarily through a Transmission Service Charge (TSC) to be paid by all power purchasers in the state as well as by parties wheeling power through or out of the state. Each utility's TSC will be based on its embedded cost of transmission, with certain important adjustments described below. LSEs will be responsible for paying the TSC of the utility in whose transmission district their load is located.[18] Transmission customers wheeling through or out of state will pay a flow-weighted average of the TSCs based on the transmission districts from which the power leaves the state. All customers paying a TSC will be entitled to access to the transmission system in the state and to obtain transmission service at a transmission usage charge based on the locational prices.

Transmission Usage Pricing -- Congestion and Marginal Losses

The Proposal establishes a transmission usage price equal to congestion charges plus marginal line losses. In effect, this is a spot transmission price paid by all users. When the transmission system is not constrained, the congestion component of this price will be zero. Users will pay the congestion charge at times when the unrestricted use of the transmission system would lead to physical flows that exceed the security-constrained limits of the system.

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18 Many of the New York utilities have noncontiguous service territories. To account for this, the Proposal defines a transmission district for each of these sub-areas, which can be used to associate specific customer load with a specific utility. In some cases, a transmission district may be associated with two utilities. In all cases, the TSC is based on the rolled-in embedded costs of the utility. The transmission assets in a transmission district are not used to calculate the TSC. As a result, all of a utility's transmission districts will have the same TSC.

Under the Proposal, all transmission users will pay these congestion costs. These payments will take one of two forms. First, parties entering into bilateral transactions (i.e., explicit transmission customers) will, through their PE, pay the ISO the difference in locational prices. This will be an explicit payment for spot transmission service for transferring power between the two locations when a transmission constraint is limiting transfers between them. Second, parties that bid injections and withdrawals into the day-ahead and hourly markets implicitly will pay this same congestion cost in the difference between the prices paid by load and received by generators. The revenue needed to make this implicit payment of transmission congestion costs is collected as a result of the PE's commodity trading activity. When the transmission system is constrained, the LBMPs from the day-ahead market (or from the hourly market) will allow the generators scheduling through the PE to be paid a low price for power that effectively is exported to an area where the LSE pays a higher price. The congestion cost component of the surplus from this trading can be identified. The PE's aggregate congestion rentals from all its commodity trading must be paid through the settlements system as the transmission charge for the trading that has been conducted through the PE.

The Proposal includes marginal line losses in the transmission usage price. Specifically, the transmission price from location A to location B will include the difference in the marginal line losses between the two locations. Such a charge reflects the additional energy lost in the form of line heating in transferring power between the two locations. Since marginal line losses exceed average line losses, such a charge will result in transmission revenues that exceed the average cost of the losses. The Proposal is for all transmission providers to credit the excess revenues in the calculation of the TSC, thereby reducing the TSC for all transmission customers. The transmission provider will not retain any of the excess revenues.

Payment of Congestion Rents to TCC Holders

In connection with the LBMP system, the Proposal calls for the creation of TCCs. TCCs will provide transmission users with the financial equivalent of firm transmission service. Any party may own or hold a TCC, including generation owners, LSEs, marketers, and others. The holder of a TCC is entitled to receive the congestion cost component of the day-ahead transmission usage charge between the two locations specified by its TCC for a specific number of megawatts. Because of this, the TCC becomes similar to firm transmission service through the following 3-step procedure. First, a TCC holder pays a fixed price for the TCC, which will initially cover a time period of up to six months under the Proposal. Second, the TCC holder pays the difference in locational prices for any transmission service actually scheduled in the day-ahead market. Third, the TCC holder is paid the congestion rentals associated with its TCC during each hour of the day-ahead market. Thus, if the TCC holder schedules transmission service that corresponds to the locations and quantities specified in its TCC, it effectively receives firm transmission service at the fixed price paid for the 6-month contract plus the cost of incremental losses in the day-ahead dispatch since the hourly payments for transmission service (steps 2 and 3, above) cancel each other, except for marginal losses. What remains is the equivalent of firm point-to-point transmission service -- payment of a fixed price for a 6-month contract that can be used to deliver power from one location to another.

The aggregate congestion charges collected by the ISO will be paid out either to holders of TCCs or to reduce the (TSC) access charges. The ISO will directly assign congestion rents to TCC holders according to their contracts. To the extent that the ISO collects congestion rents on transactions in excess of these directly assigned payments, the excess congestion rents will be allocated to transmission owners and used to reduce the TSC. None of the congestion rentals will be retained by the ISO and the ISO will not be able to profit by increasing the amount of congestion rents. Other revenues received by transmission owners from pre-existing transmission service agreements that are carried over into the LBMP system will also be used to reduce their respective TSCs.

Because TCCs will be purely financial instruments, they will impose no constraints on the actual dispatch. Thus, unlike must-take power contracts, must-run generation or strict physical transmission rights, TCC ownership alone will not affect either transmission access or transaction scheduling. The bid-based economic dispatch by the ISO will be governed by the physical configuration of the grid without regard to TCC ownership. Furthermore, TCC ownership will not confer operational control over, or an exclusive right to use, any transmission facility; in fact, TCCs will not be defined with reference to particular transmission facilities. Instead, a TCC owner will simply own an entitlement to receive the congestion rents associated with two specified locations for a specified number of MWs, without reference to any particular transmission path between those locations. 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.

Decisions to reserve the financial equivalent of firm transmission service by purchasing a TCC will typically occur well in advance of the actual hour in which service is used. Nonetheless, it is important to understand that these reservations do not permanently allocate transmission capacity and that actual use of the transmission system need not conform to these reservations. TCC holders may schedule their actual use of the system to correspond exactly with their TCCs, in which case they would receive a payment for their TCCs that would correspond to the day-ahead congestion payments. Alternatively, a TCC holder may choose not to schedule use corresponding to its TCC ownership but instead choose simply to collect any associated congestion payments made by those who do schedule.

In effect, the ISO's coordinated scheduling and dispatch, the collection of congestion payments from scheduled users, and the crediting of such payments back to the TCC 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 day-ahead opportunity cost of transmission. Failing to charge for transmission congestion associated with spot transmission 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 TCC owners for the congestion rents would have the same effect, as the TCC owner would then have little or no incentive to forgo use of transmission capacity for low-valued purposes.

TCC Auction

All transmission capacity in excess of the capacity associated with certain existing agreements (described below in more detail) will be sold in a semi-annual auction for TCCs. The sale of TCCs in an auction will ensure that the particular combination of TCCs most highly valued in the market is made available to those market participants that value them most highly. All market participants that can demonstrate creditworthiness will be permitted to participate in the auction. Participants will be able to bid to purchase TCCs, and the determination of the winning bidders will be non-discriminatory.

It is my understanding that under the Order 888 provisions, existing and prospective uses of the transmission system to meet native load would exhaust the available transmission capacity in New York. However, the Transmission Providers' Proposal would not reserve all of that capacity as under Order 888. Rather, the capacity on the system, except for capacity included under specific contracts or connected to specific facilities, would be made available for a periodic TCC auction. This capacity, in addition to the long-term TCCs that could be obtained for any expansion of the transmission grid, would be available to all participants in the market on a comparable basis. Hence, the proposed auction appears to go beyond the Order 888 requirements in making transmission capacity available consistent with pre-existing commitments.

The TCC auction initially will be conducted twice a year and the TCCs will be awarded for a six-month duration. After the market matures, TCCs for the existing system with longer durations could be sold if there is sufficient interest. In addition to any long-term TCCs obtained through expansion of the system, the longer-term TCCs would provide their owners with long-term insulation against transmission price volatility, which could be valuable to generators, LSEs or traders seeking to make investments in new generation or to enter into long-term contractual arrangements. Additional transmission capacity will become available in future TCC sales, as existing agreements are terminated, or as facility reservations are no longer required for own load.

Bids into the TCC auction will indicate the amount of TCCs desired (in terms of MWs), the injection location, the withdrawal location, and the price the bidder is willing to pay for the TCC. A version of an optimal power flow program will be used to determine the winning bidders, as described in Appendix B. The TCCs made available through the auction combined with any pre-existing rights agreements will be required to be simultaneously feasible in a contingency-constrained dispatch. The market-clearing price of each point-to-point TCC awarded in the sale will be determined in a manner analogous to that used to calculate prices in a least-cost energy dispatch. Each winning bid will pay the market-clearing price for the TCCs it is awarded.

C. Pre-existing Transmission Arrangements

In general, there will be no strictly physical transmission rights allocated on the transmission system under the Proposal, because physical transmission rights are replaced with TCCs. This section deals with exceptions to this general rule, which are required to honor certain existing transmission arrangements.

All currently existing wheeling agreements among the transmission providers, except for wheeling agreements associated with a particular transmission facility, a particular generation facility, or a particular power supply contract, will be terminated when LBMP is implemented.

Transmission providers and others currently receiving transmission service under a wheeling contract associated with a particular transmission or generation facility or power supply contract will be permitted either to keep such contracts in force or to convert them into TCCs.

If a transmission customer elects to keep the current contract in force, it will receive service identical to the service it currently receives under its existing agreements. That is, it will be permitted to inject the amount of power specified in the contract at the injection location specified in the contract, and to withdraw that amount of power at the withdrawal location specified in the contract without being charged any congestion rents for doing so, so long as the transaction is scheduled day-ahead. Transmission customers currently do not receive any compensation for transmission capacity available under their contact which they do not use. Accordingly, if the transmission customer keeps its existing rights and transacts fewer megawatts in a given hour than permitted under its contract, it will not receive any compensation for the unused transmission capacity.

Likewise, if the transmission customer injects or withdraws energy at locations other than those specified in the current contract, it would be required to pay congestion rents between the actual injection and withdrawal locations, because this would mirror the provisions of current wheeling agreements, which are limited to injections and withdrawals at locations covered under the agreement. Finally, the physical right to inject and withdraw energy under these existing contracts may not be transferred. These transition arrangements correspond to and are intended to preserve the existing contract rights of the parties.

Recipients of transmission service under existing wheeling contracts also will be permitted to convert their rights under these contracts to TCCs. The owner of such a TCC would be paid the congestion rent associated with the current contract's withdrawal and injection buses for the amount of power specified in the current contract. (If this congestion charge were negative, the TCC holder, like all TCC holders, would be required to make a payment to the ISO.) The owners of these TCCs will have the right to transfer ownership of the TCCs in the secondary market.

If the recipient of service under a current wheeling contract does not schedule and make injections and withdrawals in each hour exactly matching the amount it is entitled to transmit, the financial consequences of electing to convert its transmission rights to TCCs would differ from the financial consequences of maintaining its current rights. For example, if it converts its rights into TCCs, it will receive congestion rents regardless of its physical use of the system. So if a recipient of transmission service under a current wheeling contract converts its rights into TCCs and subsequently only injects and withdraws power corresponding to half of the transmission capability it would be entitled to use, it would continue to receive congestion rents from all of its TCCs. This differs from the current rights, whereby if only half of the physical rights are used, the party is not entitled to any congestion rents associated with the unused portion.

A number of parties other than the transmission providers currently receive transmission service under wheeling agreements in New York. These parties have options that parallel those of the transmission providers. These other parties may maintain their existing rights, in which case they will receive transmission service according to the terms of their current contract in the same manner as specified above. They may also convert their contractual rights into TCCs corresponding to the injection and withdrawal locations and transmission capacity specified in the current agreements. They would also be permitted to convey their rights under those TCCs to others, should they desire to do so.

The amount that wheeling customers (both transmission providers and others) pay for their service will be unaffected by their decision to convert their current rights into TCCs or not. Current wheeling customers that do not terminate their agreements will continue to pay the rates they currently pay, receiving either transmission rights or TCCs in exchange. The duration of these payments will also be unaffected by the decision to convert rights to TCCs or not. If a transmission provider under a wheeling contract tied to a particular transmission facility elects to continue its contract, the contract will remain in force until the termination of the relevant transmission facility agreement; similarly, contracts tied to a particular generation unit will remain in effect until that generating facility is retired, and contracts tied to particular power supply contracts will remain in force until that contract is terminated. Wholesale customers (munis) that make payments under existing contracts would not pay the TSC for energy transactions that are covered by their existing agreements.

All users of the transmission system would be charged the component of the transmission usage charge that is the difference between the marginal cost of losses in the withdrawal zone and the marginal cost of losses at the injection bus. Many currently existing wheeling agreements may include the cost of losses in the tariff paid to the transmission provider. However, the transmission providers have agreed that with the exception of external third party agreements, the recipient of transmission service would be required to make any payments for marginal losses. In the case of third party contracts, the contractual terms will not be changed, so the third party will continue to pay for losses as specified in the contract. Instead, the current transmission provider will pay for any differences between marginal losses and the losses specified in the contract.

Finally, the Transmission Providers serve their own load with existing rights. These are called Facilities Reservations in the Proposal. These rights will be converted to TCCs and later released to the ISO when no longer required. The congestion rents that each Transmission Provider receives from the TCCs it acquires through its Facilities Reservations will be deducted from the TSC paid by all load. TCCs acquired through facilities reservations therefore serve to reduce the TSC paid by all loads.

D. Installed Capacity Requirement

The ISO will establish an installed capacity requirement based on standards developed by the NYSRC in conjunction with NERC and NPCC. This requirement is intended to ensure long-term reliability by requiring sufficient resources to be secured in advance to meet projected peak loads and reserve requirements. The requirement will be established annually and will apply to all LSEs serving retail load in New York State. The New York Proposal requires each LSE to procure capacity commitments sufficient to meet its locational needs for the next year. All generation capacity procured in accordance with this annual requirement must make its availability status known to the ISO in the day-ahead market, either through a flexible bid or an inflexible schedule.

E. Ancillary Services

The proposed model provides for the provision of unbundled ancillary services, including those ancillary services that are defined in FERC Order 888. All ancillary services must be coordinated through the ISO. Regulation and operating reserves may be provided either by the ISO or procured by parties themselves (self-provision). In addition, these ancillary services will be provided at market-based pricing, while the others, because of the nature of the particular service, will be provided at regulated embedded cost pricing. The ISO will schedule and purchase ancillary services as part of its bid-based economic dispatch.

In order for a participant to self-provide an ancillary service, it must place the generating unit (or portion of a unit) providing that ancillary service under the control of the ISO, so that the ISO can dispatch it to perform that ancillary service as necessary. All self-providers would be subject to the same performance requirements as all other providers of ancillary services, and would be subject to the same penalties for failure to perform. If a participant self-provides an ancillary service and meets the ISO's performance requirements, its charge for ancillary services will be reduced by the value of the ancillary service it self-provided. The value of the self-provided service will be determined by the market-clearing price for each ancillary service. Hence, self-provision of ancillary services will be the same as sales to the market, and the ISO will coordinate these sales and purchases on a comparable and non-discriminatory basis.

Each of the ancillary services in the Transmission Providers' Proposal is described in greater detail in Appendix C.

F. Uplift

The Proposal has made a provision for the recovery of certain costs that are not included in the calculation of the LBMPs. These costs are recovered by a separate pricing component, uplift, that would be paid in addition to the LBMP charge for energy or transmission usage. Uplift is used to recover costs in three major categories: the net cost of the ISO's emergency external transactions, shortfalls in the within-day collection of congestion rentals, and any minimum generation or start-up costs in excess of LBMP revenues.

The net cost for emergency transactions is not included in the ordinary calculation of LBMP and so, must be recovered separately through uplift. In such cases, the ISO will collect uplift to cover shortfalls in congestion rentals. This may occur, for example, when a transmission line has an unexpected outage during the day, leaving the ISO with more dispatch commitments to settle than it has transmission to provide. As a result, the revenues collected by the ISO through congestion cost pricing may not be adequate to honor all day-ahead dispatch commitments. No uplift is collected, however, to cover congestion rent shortfall that arises in settling TCCs in the day-ahead market. If there are insufficient congestion rents day-ahead, both TCCs and MWAs are curtailed on a comparable basis.

The third type of uplift recovers energy generation costs of generating units committed by the ISO in the day-ahead market that exceeds the LBMP revenue that the generators earn in that market. This uplift is used only to recover costs that are not recovered automatically in the LBMP. For most occasions the total amount of revenue needed by each generator scheduled in the day-ahead market to cover both its running, minimum generation and start-up costs (as reflected in each generator's bids) should be recovered through the revenue the generator earns based on LBMPs calculated based on running costs alone. This would happen if the bid-in running cost of the marginal generating unit were high enough, relative to the running costs of units with start-up and minimum generation costs, to cover each generator's total costs. However, marginal cost pricing, by itself, sometimes may not support an efficient solution to the unit commitment problem because of fixed minimum generation and start-up costs. This is discussed in greater detail in Appendix D. In this circumstance, the LBMPs would not provide adequate revenue for each generator to recovery minimum generation and start-up costs, and the ISO would compute the shortfall for each generator separately based on the day-ahead schedules and LBMPs. The resulting uplift will be charged equally to LSEs based on the MWhs they actually withdraw from the grid during the day.

G. Summary of Proposal

Under the New York Proposal, all users will have comparable options and receive comparable pricing and scheduling treatment. All users will be able to acquire TCCs, 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 ISO for supply and demand. The ISO will dispatch 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. All of these considerations work to promote economic efficiency, as discussed below.

II. THE PROPOSED SYSTEM WILL SUPPORT SYSTEM RELIABILITY

The proposed system builds upon the existing operational procedures used for maintaining reliability in New York. The ISO will be responsible for operating the New York bulk power system in accordance with industry reliability criteria, as specified by the proposed New York State Reliability Council (NYSRC). The NYSRC will be responsible for developing criteria consistent with those of NERC and NPCC. The ISO will have all of the operational capabilities for discharging this responsibility as does the current New York Power Pool (NYPP). Nothing in the Proposal degrades the ability of the ISO to maintain reliability or to respond to emergencies.

Under its current rules, the NYPP does not engage in a centralized unit commitment process. Instead, the individual utilities are responsible for committing an adequate number of generating units to serve their own load. Under the Proposal, the ISO will maintain reliability conducting a centralized security constrained unit commitment and dispatch as part of the day-ahead market. Through the operation of this market, the ISO will have sufficient lead time to ensure that sufficient capacity is on-line to maintain system reliability.

In addition, each LSE must provide a forecast of its next-day load to the ISO and each generation resource obtained through the installed capacity market must make its availability known to the ISO either through a flexible bid or an inflexible schedule. These safeguards are intended to provide the ISO with the information it needs to ensure that an adequate number of generating units are committed for the next-day's market. The economic information obtained through the bidding process and the absence of restrictions on who can provide bids to the ISO will allow the ISO to maintain reliability at the lowest bid-in cost.

The Proposal has several additional features that are expected to assist the ISO in operating the power system in a reliable manner. First, the locational-based marginal pricing (LBMP) system will, as a basic matter, provide appropriate price signals to all market participants. A generator that is needed in constrained areas will be paid an appropriately high locational price if needed for reliability purposes. This will provide an economic inducement to generators that a regulated market cannot match. Likewise, LSEs or customers in such a constrained area will have an incentive to decrease their energy consumption either in anticipation of expected high market-clearing prices or through dispatchable bids that can be submitted to the PEs and the ISO. These market forces will be a formidable engine assisting the ISO in maintaining reliability.

Second, the coordination of the day-ahead and balancing markets will provide the ISO with a well defined set of resources that can be used to evaluate and deal with transmission constraints effectively. The ISO can request, or in emergencies order, units to start up in constrained areas if needed to maintain reliability and it can assure each such generator that its participation will be appropriately compensated.

III. THE PROPOSED SYSTEM WILL PROMOTE EFFICIENCY AND LEAD TO LOWER COSTS

The proposed system effectively converts the existing New York Power Pool structure from a shared-savings market to a competitive, bid-based market. Overall, the Proposal encompasses five separate markets for five different time horizons. From the longer to the shorter time period, these are markets for: (1) installed capacity; (2) TCCs; (3) day-ahead unit commitment and dispatch; (4) energy balancing and dispatch; and (5) regulation service to provide automatic generation control during 6-second intervals. Three of these markets in particular (for TCCs, day-ahead commitment and dispatch, and the balancing dispatch) are closely inter-related. Together, they comprise a system of bilateral transactions and voluntary pooling arrangements for energy trading and unit commitment that will promote competition among all generators and loads while ensuring that reliability is maintained under a bid-based economic dispatch.

The markets have been designed to be mutually consistent and share several fundamental characteristics. First, except for the installed capacity market for LSEs, participation in each market will be voluntary. Bilateral arrangements can be made over virtually any time horizon. In addition, no one has to buy TCCs, no one has to bid flexibly into the day-ahead market (although generation capacity obtained in the installed capacity market is required to enter either a bid or an inflexible schedule in the day-ahead market), and no one is required to bid flexibly into the balancing market. Second, all of the markets are conducted and cleared through centralized, bid-based auctions that are open to any qualified participant. Third, all of the markets use the same definition for transmission service and apply the same standards for assessing the capability of the transmission system. The basic standard is that all energy flows on the grid must be simultaneously feasible while maintaining grid reliability. Fourth, all of the markets provide efficient price signals that promote the participation of the least-cost suppliers (in the sense of the lowest offers to sell in the market) and the highest valued users (in the sense of the highest offers to purchase from the market). Fifth, all of the markets have been designed to provide comparable treatment for all wholesale power market participants.

Perhaps most importantly, the foundation of all of the markets is a system of locational-based, transparent prices for energy and transmission. These LBMPs emerge from the auctions that are conducted for each of the central markets and represent the market-clearing prices for the auction-based trading that occurs over and above any pre-existing commitments. Examples of such pre-existing commitments could be bilateral energy transactions in the balancing market, or bilateral unit commitments in the day-ahead market. The locational prices will respond as market conditions change over time and also from one geographic location to another. This LBMP system is the key to an efficient energy market that includes bilateral transactions and it ensures comparable treatment for all users of the system. Likewise, TCCs are defined so that transmission prices are fully integrated with this set of efficient energy prices. That is, the locational basis of the transmission pricing associated with the TCCs is the same as the locational basis of the energy prices. Similarly, units are committed in a way that accounts for the locational consequences of asking generation units to incur start-up costs or to provide operational reserves. This set of interrelated markets accommodates competition, transmission limitations, and reliability all at the same time. The numerical examples in Appendix A illustrate how the LBMP works and help in understanding why the proposal approach promotes economic efficiency.

A. Overview of the Efficiency of the Proposed LBMP

The LBMP method is consistent with efficient supply and demand for power. Because the energy markets (both the day-ahead and the balancing markets) determine the bid-based economic dispatch of grid resources to meet load, the resulting set of locational prices generally equates the marginal cost of supplying an increment of load at each location (as defined by generator bid prices) with the load's marginal willingness to pay for additional power at that location. All those who are willing to pay at least the locational price for power are supplied with power at that price and, conversely, any flexible load that is not willing to pay as much as the locational price can reduce its demand and avoid payment. Since all LSEs or customers pay the locational marginal price, only customers willing to pay the true marginal cost of supply will take the power, unlike a system based on average-cost prices where the marginal cost of supply can be greater than the average-cost price paid by consumers thereby encouraging uneconomic consumption and removing incentives to reduce congestion. Similarly, all suppliers willing to sell power at the locational marginal price are accommodated in the market, while those unwilling to supply power for such a price are not required to produce. Consequently, the set of locational prices corresponds to an efficient equilibrium in which no load or generator is dissatisfied with the resulting consumption and production schedule and dispatch, assuming that the market participants are acting as competitors and cannot exercise market power.[19]

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19 Importantly, generators will be paid the market price at their location rather than their bid price. Such a system permits generators to bid their costs rather than their estimate of the market price yet ensures that they will be paid the market price. Pricing systems that pay generators their bids rather than the market price have several disadvantages. First, under such a pricing rule, generators would seek to bid the market price rather than their costs, reducing economic efficiency. If generators seek to bid the market price, the inability of generators to consistently forecast market prices would lead to mistakes which would raise consumer prices and producer costs. Thus,

By pricing congestion directly through the LBMP prices, the Transmission Providers' Proposal avoids the need to sweep congestion costs into an "uplift" and the many problems this would create. Using an uplift to recover congestion costs is a much-criticized feature of the system used in England and Wales. 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.[20] 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 for transmission capacity.[21] Additional discussion of uniform pricing rules is provided in Appendix E.

The energy markets (both day-ahead and the balancing market) can accommodate bilateral contracts and also can allow generators to participate in economic unit commitment and dispatch while selling their power through bilateral contracts. Under the proposed rules, a generator entering into a bilateral contract can always choose to self-schedule with the ISO (through a PE) and operate inflexibly (i.e., without price-responsive bids) in either the day-ahead or balancing

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suppliers that overestimate the market clearing price would not be scheduled and customers would not be served at least cost, raising prices. Such a bidding system would also create an artificial competitive advantage for market participants with superior access to information regarding market demands and transmission schedules, although these entities may be less efficient than other market participants on a level playing field. Finally, since all of the generator bids will tend to be quite similar under such a system, it would unnecessarily complicate the ISO's dispatch.

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

21 There are other examples of inefficiencies associated with postage stamp pricing including inefficient bypass of the central market. The bypass incentive is created because power prices in regions separated by transmission congestion cannot fully reflect the differences in regional costs, with the result that some low-cost suppliers that are not used in the central market attempt to find buyers on a bilateral basis outside of the central market. In England and Wales, this bypass problem was avoided by a no-bypass rule that forbids bilateral trading.

markets. This type of inflexible schedule is sometimes called a physical bilateral transaction.[22] In addition to scheduling an inflexible bilateral transaction, however, a generator could bid its power flexibly into either market through a PE by providing the appropriate incremental and decremental bids. By bidding into the centrally coordinated markets, a bilateral generator can take advantage of opportunities to fulfill its contractual obligation to its buyer at lower cost than by generating the power itself. If a generator with a contract to sell at a fixed price bids into the centralized market 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 central market at a price that is less than its own bid. The incentive to participate in the centralized dispatch promotes economic efficiency.

All users of the grid pay a spot transmission usage price (congestion charges plus marginal line losses) that promotes efficient grid usage. Bilateral transactions must explicitly pay this transmission price to the ISO through a PE. Participants in the central markets will pay this price implicitly through the LBMP system. The congestion charge component of this price is no higher than it must be in order to allocate limited transmission capacity to the most highly valued uses. If regulatory rules, for example, somehow limit the transmission price to be less than the true congestion costs, customers will schedule more transmission use than can be accommodated, in which case some other method must be found for rationing the limited capacity. Any such non-

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22 Parties to a physical bilateral transaction do not use the financial settlement arrangements of a PE to buy and sell power at the LBMPs. Instead, a transmission price must be paid, which is based on the LBMPs. Alternatively, the buyer and seller could arrange the same transaction through a PE if they wish. Since a PE would settle separately with the buyer and seller, the parties would need a contract specifying their financial arrangements with one another. This is sometimes called a Contract For Differences (CFD), which establishes a contract price for trades between the buyer and seller and indicates how the parties intend to compensate one another relative to the price used by the PE to settle their separate accounts.

price rationing rule would lead to other substantial difficulties and inefficiencies. Furthermore, such non-price rules typically require restructuring on customer choices. As In England and Wales, for example, a non-price transmission allocation rule would likely require substantial restrictions or prohibitions on bilateral transactions. So, the congestion pricing portion of the Proposal is needed to promote economically efficient use of the grid and to support bilateral transactions. The marginal line loss component of the transmission price likewise is needed for economic efficiency. Any system based on average line losses does not fully reflect the marginal cost of trading using the grid, and so will involve some degree of inefficiency. In addition, the computation of average line losses can be controversial because the calculation is sensitive to the selection of certain benchmarks, such as the swing bus. A straightforward way of avoiding these inefficiencies and complications is to charge for marginal line losses.

<u>Paying generators that choose to bid into the central markets a LBMP price will encourage new generators to locate where the power they produce would be the most valuable to the load on the grid</u>. Under the Transmission Providers' Proposal, the price that a generator will receive for marginal power delivered to the grid will be the bid-based locational marginal cost at the location where the power enters the grid. This will encourage new generators to locate where the locational price is high, which means that the cost of meeting load at that location is high. In contrast, pricing systems that would pay the same price to all generators, regardless of location, would not provide appropriate incentives for investors to locate new generation where it would be the most valuable for serving load. In addition, the proposed pricing system creates an

incentive for owners of existing generators to invest so as to be available during periods when high prices are expected, adding to efficiency.

The LBMP pricing approach also encourages the addition of new transmission to relieve grid congestion efficiently. The centrally coordinated markets will provide price signals to guide efficient transmission system expansion. Any LSEs or customers that face high prices due to transmission system constraints have an incentive to invest in transmission system expansion to relieve the congestion, as does a generator that is not fully dispatched or receives a lower price due to the same constraints. Pricing systems that are not locational do not provide customers or generators with a direct economic incentive for efficient expansion of the transmission system; instead, they must rely solely on traditional regulatory processes.

Charging LSEs the LBMP encourages new customer loads to locate where they can be supplied most cheaply. Under LBMP pricing, all LSEs are charged the bid-based marginal cost of supplying power at their locations. LBMP prices will be higher in areas where transmission constraints prevent cheap power from being imported. Large customers, in particular, therefore have an economic incentive to locate in unconstrained areas where power can be supplied most cheaply. If the price charged to a customer does not vary by location even though the transmission grid is constrained, buyers would have an uneconomic incentive to locate in areas where it is expensive to supply power since they would not pay the full additional cost that serving them imposes on the system dispatch. Customers also have an incentive to adjust their consumption patterns and to make investments on their premises so as to conserve during periods of peak usage when prices are high due to transmission constraints or other considerations. The hourly locational prices will encourage price-responsive load in effect to shift consumption to time periods and locations with lower prices. Such state-wide trade-offs are made possible by the LBMP system and go beyond those possible under the utility-specific, average-cost pricing that prevails today.

The Transmission Providers' Proposal provides price certainty for those who acquire certain transmission obligations, called TCCs. A TCC is a financial instrument that can be used to hedge transmission congestion costs whether or not actual grid usage matches the TCC. As discussed elsewhere, if grid usage does not match the TCC then congestion costs paid for use will be offset by the congestion rentals paid to a TCC holder, so that firm transmission service in effect is obtained at the price paid for the TCC itself. Alternatively, if grid use does not exactly match the TCC, then the TCC owner will still be hedged against congestion costs between the two locations referenced in the TCC.[23] This will enable customers and suppliers to efficiently hedge the congestion costs associated with their trades. These TCCs can be traded in a secondary market, allowing additional efficiencies to be achieved.

The LBMP approach does not introduce transmission pricing uncertainty. In the proposed LBMP method, prices are determined *ex* post, after the bids and schedules are submitted. Some observers have concluded that the *ex post* prices under LBMP means that prices are uncertain. This is not true as a general matter. Any eligible customer can obtain transmission service at a known price by buying a TCC, which can lock in a transmission price for up to six months. In

23 Under the LBMP system, the term "firm transmission service" no longer will be used. This is because the concept of non-firm service (where the utility interrupts the customer's use for economic reasons) is obsolete under LBMP and also because the Proposal is based on financial, as opposed to physical, transmission rights. The transmission pricing

addition, anyone can enter into a day-ahead schedule on the condition that the schedule be reduced based on price, which would give parties a substantial degree of price certainty in scheduling spot transactions. This could be accomplished by submitting to a PE an inflexible schedule from location X to location Y that would be withdrawn in part if the day-ahead LBMPs were greater than or less than the prices bid for withdrawals or injections.

It is true, however, that parties wishing to schedule day-ahead transactions without a TCC will not be able to observe the final spot transmission price before deciding whether to participate in the market, which is, of course, true for the spot price in any market. However, the magnitude of the price uncertainty is likely to be small. Secondary trading of TCCs and other forward contracts will establish a price that should approximate expected congestion costs, which is the same fundamental result that could be obtained by bilateral trading, if bilateral trading were capable of dealing with the network interactions. The remaining uncertainty that any system of transmission pricing must address is how to recover the difference between the grid's actual congestion costs and those that were expected in the day-ahead market. Any PE may offer fixed-price transmission service (in effect) and bear the associated risk of higher market-clearing congestion prices. So, if complete price certainty is important to a transmission customer, PEs will be willing to provide such a service at a market-determined premium that allows the customer to avoid the residual price uncertainty associated with obtaining the spot transmission service. The ISO, however, could not offer such fixed-price transmission service beyond TCCs without itself taking a position in the market and, in effect, undertaking a financial risk management

system administered by the ISO allocates transmission use to the highest valued uses in a non-discriminatory way using bid information from all transmission users.

business, which would be inconsistent with its charter as a not-for-profit organization that retains none of the congestion rentals.

The Proposal promotes reliability in part through continuation of an installed generation capacity requirement for New York LSEs. While some may believe that it is possible to maintain adequate installed generation to preserve current reliability levels purely through market incentives, the Proposal 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 Proposal 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.

Although a full analysis of market power is beyond the scope of this report, it is important to note that LBMP pricing itself helps to mitigate market power. While LBMP pricing alone cannot prevent the exercise of horizontal market power by generators, at the margin LBMP 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 customers located in constrained regions will pay the same prices that will be paid to similarly located generators, any exercise of market power by generators in a constrained region would provide customers with an incentive to enter into long-term contracts with competitive entrants, ensuring recovery of entry costs and thus facilitating entry. In addition, any exercise of market power by generators would lead to a demand response by customers that would reduce the profitability of exercising market power. In contrast, any Proposal other than LBMP that results in some form of average prices, such as average prices across the entire market, would dull the price signal, thereby reducing the responsiveness of demand and making it easier for a dominant generator to exercise market power.[24] Moreover, use of LBMP does not preclude or hinder the use of other measures that may be appropriate for mitigating particular instances of market power.[25]

B. Centralized Market for Unit Commitment and Dispatch

The Transmission Providers propose a pair of centrally-coordinated markets in which parties may make binding obligations that carry forward from the day-ahead market to the balancing market. Settlements in the day-ahead market are based on the locational prices from that market. Settlements in the hourly market are based on the 5-minute prices occurring during each hour's actual dispatch.

The Proposal will create an integrated market for energy, regulation, spinning and non-spinning reserves that will ensure that these and other ancillary services are acquired at least cost, and provides the ISO with unrestricted access to the resources it needs to balance the system and maintain reliability. In particular, the proposal does not impose any artificial restrictions on who may provide ancillary services, nor does it create artificial restrictions on the scheduling and bidding process that would create artificial limitations on the ISO's flexibility in scheduling resources to meet load at least cost. This system provides appropriate incentives for generators

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24 The Transmission Providers propose that load prices be averaged in a few zones, at least initially, where prices are expected to be similar. Metering is not currently available to measure and price the load of individual customers.

25 In a competitive market in which generators are paid the market price, the economically efficient bidding strategy would be for generators to bid their costs. This principle can be used by regulators to examine whether generators are seeking to exercise market power by comparing bids to costs, at least during a transition period while cost information remains available.

to follow the dispatcher's instructions during the hour. The separate consideration of start-up and energy bids eliminates speculation on the part of a generator's operator of whether or not it would be profitable to start up the unit. Likewise, the payments for operating reserves and regulation services relieves the operator of a generating unit from needing to second guess whether it would be profitable to produce energy rather than provide spinning reserves. Such speculation or second guessing likely would lead to inefficient decisions.

The coordination of the day-ahead market by the ISO serves two principal purposes -- it facilitates efficient grid usage and it ensures reliability. First, the efficiency of grid use is addressed through the system of TCCs and LBMPs. The transmission usage pattern associated with a TCC is effectively reconfigured as a result of the bids in the day-ahead market. The bids of suppliers and LSEs indicate the value attached to transferring power between and among grid locations. Some of these scheduled injections and withdrawals of power correspond to TCCs held by an interested party. Some do not. If the value of a bid to schedule grid usage not covered by a TCC exceeds the scheduling market of the TCC holder, it would be efficient for the non-contract usage to substitute for the TCC holder's usage since all parties would be better off. The ISO's day-ahead schedule effectively arranges for these types of efficiency-enhancing trades on a transmission grid that can exhibit complicated network interactions. These interactions require some type of central market coordination in order to reach an efficient outcome. This is provided by the ISO's scheduling algorithm that evaluates locational bids and transmission constraints simultaneously.

Second, system reliability is enhanced by a day-ahead market that requires the ISO to conduct a central market that accommodates the need for a day-ahead commitment of generating units. That is, the ISO will be able to assess the availability of generators and transmission facilities from the information available a day in advance, and have adequate time to take appropriate corrective action. The Transmission providers have concluded that hourly information at times could provide inadequate advance warning for the ISO to take actions to maintain reliability.

The unit commitment issue arises because some generator units must be started up (or committed) 12 or more hours before the time they will be needed to generate electricity. This means that it is not feasible to wait until the hour in which they will be needed to decide whether or not to start them. On the other hand, it would not be economic to simply start up all units that might or might not be needed, as appreciable costs can be incurred to start units up or to run them at minimum load until they are needed. Someone therefore must forecast load and generation and decide which units should be started up a day ahead (or kept available by running them at minimum load) in order to meet the next day's load.

The Transmission Providers propose that this commitment decision may be handled in either of two ways. First, any generator may make its commitment decision either on its own, through a bilateral contract, or in conjunction with traders in the PE through which it communicates with the ISO. In this case, the generator's bids to the ISO would not include any start-up or minimum load costs but would only include running cost bids (if the generator bid into the pool dispatch) or a schedule (perhaps with associated incremental and decremental bids) in the case of a generator purchasing transmission from the ISO. Second, any generator may also make its unit available for commitment by the ISO, by submitting both start up and minimum load bids to the ISO as well as its running cost bids. These start-up and minimum load bids would enable the ISO to determine whether or not it would be economic for the ISO to commit the unit so that it would be available to balance the system in real time.

The start-up costs and minimum-running levels of some generators introduce a significant complication into the process of determining economic dispatch. This is not a new problem. It is a complication that some tight power pools and individual utilities have routinely addressed in the past using cost-based information. The Transmission Providers propose to address the same issue using bid-based information. The technical difficulty introduced by start-up costs and minimum running levels is finding the combination of generation units that can meet a given level of load at the least bid-in cost. In this problem, fuel is a bid-in variable cost, while the start-up costs are bid-in fixed costs. Starting more plants may allow the PEs and the ISO to achieve fuel cost savings, but at the expense of higher fixed costs. Assessing the trade-off between fuel costs and start-up costs and minimum generation can be a complicated matter, especially in electricity markets with minimum running constraints and transmission constraints.

Finding an efficient solution to the unit commitment problem is substantially more difficult when transmission constraints restrain power flows from generation with cheap fuel costs or low start-up and minimum generation costs. When the grid is constrained, the trade-offs to be assessed in committing units include the electrical interactions between locations. That is, it may be necessary to meet demand at one location only by increasing the supply at a second location by two units while decreasing the supply at a third location by one unit, and so on. These types of trade-offs occur due to network interactions when constraints are encountered. These network interactions introduce additional complications when assessing the relative start-up costs of units at one location versus another. As grid usage changes, these trade-offs can be significantly different from one period to the next with the result that a trading pattern and unit commitment that achieves efficiency in one period may not be efficient in another.

In theory, a simple one-part energy pricing system may never support the least-cost solution in the presence of startup and minimum load costs. In practice, the Transmission Providers have made the judgment that these complications make it improbable that bilateral transactions could discover efficient patterns of the final unit commitment in combination with energy trading to accommodate such dynamic market conditions. Nor, from a public policy standpoint, would it be appropriate for generators that are direct horizontal competitors in the energy and ancillary services markets to exchange operating plans and enter into private discussions and agreements regarding their collective commitment decisions and operating levels. Instead, a degree of central coordination by the ISO is required to ensure that reliability is maintained, at least cost, within the framework of a competitive market. The ISO's unit commitment auction promotes competition through competitive bidding without wasting resources by committing or running units inefficiently, which is the likely result under rules that would prevent the ISO from coordinating a voluntary day-ahead market.

The day-ahead market will also schedule operating reserves and units that will provide reactive support and regulation service during the hour. By addressing unit commitment, energy dispatch, reserves and regulation in a single least-cost scheduling process, the ISO will be able to find the bid-based economic solution for this combined set of problems using any resource willing to participate. This will help to ensure that efficiency is not sacrificed by artificially restricting participation in these markets and thereby preventing competitive trade-offs from being assessed between and among them.

It is important to recognize that generators and traders are not required to make commitment decisions through the centralized market coordinated by the ISO. All generators can make their own commitment decisions and either provide the ISO with a bilateral transmission schedule for the output of the units they commit, or provide the ISO with running cost bids for the dispatch of committed generators at levels above minimum load. Because the Proposal permits any PE to make its own commitment decisions, traders that believe they can make more efficient commitment decisions than the ISO need not rely on the ISO for commitment. Nevertheless, the ISO's role in maintaining reliability requires that it be able to take into account all schedules, and the need to minimize the costs incurred in maintaining reliability requires that the ISO have the opportunity to commit units on a bid basis to balance load and maintain reliability. If centralization is not needed for the ISO to do its job, then its access to centralized information will not provide it with any advantage over decentralized PEs. If, on the other hand, the centralized unit commitment by the ISO provides important cost savings due to the ability to take account of transmission constraints, then generators likely to be affected by transmission congestion would indeed prefer to be scheduled by the ISO. This is not unfair, but merely indicates that failure by the ISO to rely on such a centralized unit commitment process to balance the system and maintain reliability would artificially raise the cost of using the grid. This might be good for some competitors who could profit from the inefficiencies, but it would not be good for competition nor would it be good public policy.

The structure of the day-ahead market therefore provides an opportunity for parties participating in bilateral transactions to bid the generation into the centralized markets on a flexible basis, to the extent that they wish. By bidding flexibly, a generator entering into bilateral transactions will be able profitably to increase its output beyond its bilateral scheduled amount during periods in which it can supply incremental energy more cheaply than the ISO's LBMP. Likewise, it may find it profitable to reduce its output from its bilateral schedule if energy purchased in the ISO coordinated dispatch can supply its load more cheaply than it can itself. Each bilateral participant can make its own judgment of the degree to which it wishes to participate in the ISO coordinated day-ahead dispatch. If it wishes to enter solely into bilateral transactions and to forgo the opportunity to participate in the auction-based markets, it may do so. The pricing system would not affect this choice. However, to the extent there are real cost-savings, there would be incentives for a bilateral generator to participate in the coordinated auctions, especially if it does so on a flexible basis. Such participation benefit all market participants, by reducing the costs incurred by the ISO to balance the system and maintain reliability and would also benefit the parties to bilateral contracts by reducing their costs and raising their revenues.

The significant feature of the day-ahead commitment by the ISO therefore is not that it forces any generator to participate in the day-ahead unit process coordinated by the ISO but that it permits generators that are uncertain whether day-ahead market prices would be high enough to justify commitment of their unit, to provide the ISO with bids and make the units available for commitment and dispatch by the ISO. This flexibility will benefit the participating generators by raising their revenues and reducing their costs, but also benefits all transmission grid users by improving reliability and reducing the costs the ISO incurs to balance the system and maintain reliability. A system that precluded generators from providing the ISO with bids for commitment would likely reduce reliability, raise the costs to grid users of operating the system and would likely violate comparability requirements. Thus, such restrictions would reduce reliability and raise grid costs in any hour in which a generator needed to maintain reliability at least cost was not available because as of its inability to forecast the ISO's need for its resources. Moreover, such restrictions would likely raise artificial barriers to the commitment of generation to support the transmission transactions of some grid users but not others.

Consider, for example, a generator that is sometimes, but not always, needed to provide voltage support. If this generator were precluded from providing the ISO with bids allowing the ISO to commit its unit when needed to support transmission schedules, the generator would only be available for use by the ISO to support voltage during those days during which the generator correctly forecasts that the ISO would need to call on it to maintain reliability at least cost. The generator's imperfect ability to forecast overall grid usage would mean that the unit often would not be available when it is economic to use it to support transmission schedules, thereby artificially raising prices in the constrained area and raising generator costs. While these kinds of restrictions would undoubtedly benefit large traders who might have an advantage relative to small traders in predicting the need for voltage support, precluding the ISO from making use of the information available to it to schedule voltage support when needed would reduce reliability, raise grid costs, and serve no pro-competitive purpose.

The same kind of forecasting problem and reliability impact can arise from transmission system stability limits. I understand that the transfer capability of the Central East interface depends on the number of units Sithe has operating, the number of Units committed at the Oswego complex, and various other system configuration parameters. The Proposal would permit the ISO to commit generation at Sithe or Oswego based on the bids of the generators when this commitment would be the least-cost method of providing transmission to support the schedules of bilateral and pool customers. No individual trader could accurately forecast the need to start these units to provide transmission support unless it had access to the schedules of all of its competitors, which it would not, and should not have. The ISO, of necessity, will review these schedules in its role of scheduling the system and maintaining reliability and is in the position to commit of units needed to maintain system reliability.

The Transmission Providers have therefore made the judgment that the ISO should include a unit commitment auction in its consideration of the day-ahead bids and schedules. This auction provides an efficient solution to the need to maintain reliability at least cost that can accommodate competition between generation units with varying levels of running costs and start-up costs. Without the ISO's ability to schedule resources day ahead, the ISO cannot maintain reliability at required levels and there is a non-trivial risk that the wrong units would be committed with the result that the bid-in expense of meeting a given level of demand would be higher than necessary.

The unit commitment issue can be viewed as an example of a problem that an economist would say includes economies of scale (fixed start-up costs) and network externalities. Such a problem could lead to an inefficient equilibrium if left to the competitive marketplace. On the other hand, the scale economy in this case is one that recurs every day for hundreds of generating units, suggesting that the marketplace may be able to arrange adequate, if perhaps imperfect, recurring solutions to accommodate this difficulty. In my view, it is reasonable to begin the transition to competition by making the conservative assumption that the unit commitment problem is best addressed in a central marketplace. The rapidly changing nature of the network interactions suggests that bilateral transactions may not be well equipped to deal with this problem, at least at the outset. If regulators or the industry determine with experience that bilateral markets would be adequate, there would be little or no such bidding into the ISO, and the unit commitment would automatically revert to the bilateral market.

The Transmission Providers propose that costs incurred by the ISO to commit units in both the day-ahead schedule and the real time dispatch that are not recovered in energy and ancillary services prices or assignable to individual grid users will be recovered in uplift, as discussed in Appendix D. The uplift for units committed by the ISO is allocated equally to all actually grid users because it is a cost incurred jointly to provide reliability and energy. The potential allocation problem can be illustrated by considering the costs of maintaining reliability through spinning reserves. If additional generators are committed to provide spinning reserve, total start up costs to be recovered in energy prices by generators will be larger, and energy prices will likely be lower than would otherwise be the case. The opportunity cost payments made to providers of spinning reserve may be inadequate to recover the start-up costs. If so, uplift payments would be needed to support the efficient provision of spin. While it may ultimately be possible to develop pricing algorithms that causally allocate uplift payments to each ancillary service or transmission transaction, these algorithms do not presently exist and, if some of these costs are truly joint, may never exist. Absent a current ability to causally allocate all uplift payments to particular services and customers it is necessary to recover these charges from all transmission grid users.

An alternative approach to a unit commitment auction conducted by the ISO might be for the ISO to enter into long-term contracts with the generators whose dispatch could be used to balance the system. One limitation of such an approach is that the set of generators whose dispatch might be the least cost method to balance the grid over the course of the year would likely encompass most or all of the generators connected to the grid. If all of these generators were provided such long-term contracts, this approach would in effect reinvent the vertically integrated utility under another name, rather than facilitating the development of a competitive power market. This expansion of the role of the ISO, and curtailment in the role of market forces, might be forestalled by imposing a regulatory limit on the number of generators that could enter into such dispatch contracts with the ISO. The difficulty with such artificial restrictions is that they would raise consumer costs because they would prevent the ISO from balancing the system at least cost in some periods and might also compromise reliability.[26]

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[26] Additional issues regarding unit commitment are discussed in Appendix D.

C. The Two-Settlement System

The relation between the day-ahead market and the hourly balancing market is addressed in the two-settlement system. The two-settlement system is to give parties the option of committing to make a trade as early as the day before delivery or as late as 90 minutes before delivery.[27] Parties that elect to make day-ahead dispatch commitments will have these converted into corresponding obligations in the balancing market. If a party decides not to participate in the day-ahead market, it will be obligated only for the trading commitments made in the balancing market and a share of any start-up and minimum generation costs of units committed by the ISO that must be recovered through an uplift charge. The sequential markets accommodate trading information that develops early, as well as that which develops closer to the delivery hour.

While day-ahead trading is optional, any dispatch commitments actually acquired are binding financial commitments. In effect, the ISO's day-ahead schedules become dispatch commitment in the balancing market. Participation in the day-ahead market means that the trader either (1) is obligated to take delivery as a buyer or to make delivery as a seller, or (2) is obligated to settle any differences at the prevailing hourly price. This financial-settlement requirement means that a supplier will buy (and pay the hourly price for) any power that it scheduled on a day-ahead basis but does not actually deliver in the balancing market, and that a buyer will buy (and pay the hourly price for) any delivered power that it did not schedule. Similarly, a supplier sells (and receives the hourly price for) any power actually delivered in the balancing market (at the ISO's instruction) that was not scheduled a day ahead, and a buyer sells (and receives the hourly price for) any power that it does not consume but had scheduled in the day-ahead market. So, all deviations from the day-ahead scheduled commitments are settled at the prices prevailing in the hourly balancing market for both buyers and sellers.

The effect of the two-settlement rules is different from a take-or-pay obligation in two ways. First, under a take-or-pay obligation, the buyer pays for shortfalls in its purchasing obligation at the same price paid for the remainder of its purchases. Under a two-settlement system, different prices are used to settle fulfilled and unfulfilled obligations. A party that deviates in the balancing market from its day-ahead schedule settles the difference at the second settlement price. This is justified because it is the market price of the deviation. A second difference is that a two-settlement system does not impose an inflexible purchasing obligation on buyers or an inflexible selling obligation on sellers as would a take-or-pay obligation. Instead, the quantities bought or sold by any party in the balancing market may deviate from the amounts it had scheduled in the day-ahead market. Any such deviations are cleared by imputing as a sale any unfulfilled buying obligations, and so on.

This conversion of day-ahead schedules into dispatch commitments is a fundamental safeguard against market manipulation. As proposed, the two-settlement system provides less opportunity for strategic behavior than a single settlement system because it requires market participants (PEs) to make financial commitments to their day-ahead schedules. Systems that do not require a financial commitment to day-ahead schedules would provide the opportunity for individual market participants to schedule transactions a day ahead – which, due to transmission

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[27] The actual closing time for each market must be early enough to allow for the administrative processing of bids, and

system interactions, affect the schedules of other parties – and then back away from the schedules in the actual dispatch without any potential financial consequence. Market participants engaging in such behavior could potentially affect the LBMPs that sellers receive, the LBMPs paid by buyers, and the congestion costs paid for bilateral transactions. In contrast, the settlement of the dispatch commitments under the voluntary two-settlement system provides appropriate price signals for those that have chosen to make day-ahead financial commitments by scheduling with the ISO and wish to change their schedules in the hour. In addition, if parties change their schedules, and adversely affect the cost or feasibility of the schedules of other parties due to network interactions, the settlement of the dispatch commitments provides the revenue for compensating those whose schedules are affected.

The day-ahead settlement of TCCs is another important consideration in this two-settlement system. Holders of TCCs are paid the congestion rentals based on the day-ahead prices. However, this does not impose any commercial restrictions on using the TCCs to hedge energy transactions.

Under the two-settlement system proposed by the Member Systems, charges to load scheduled in the day-ahead dispatch would be based upon LBMP prices computed in that dispatch. Payments to holders of TCCs would also be based upon LBMP prices computed a day ahead. In the example of a day-ahead dispatch used in Appendix A to illustrate the two-settlement system, East DC #1 schedules 70 MWh of load a day ahead, so it would be charged the day-ahead Eastern zonal LBMP of $45.81/MWh for 70 MWh, since Bus W (East DC #1's

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for the start up of committed units in the case of the day-ahead market.

location) is in the Eastern zone. East DC #1 also owns a TCC, so it would be paid the day-ahead congestion cost in the Eastern zone, minus the day-ahead cost of congestion at Bus B, for 70 MWh. (Each congestion cost is computed relative to the reference bus.) The Eastern zonal congestion cost is the load-weighted average of the cost of transmission congestion, relative to the reference bus, at each bus in the Eastern zone, weighted by load at that bus. In the example in the appendix, the day-ahead congestion cost in the Eastern zone is $9.74/MWh. The cost of congestion at Bus B is zero, so East DC #1 receives a payment of $9.74/MWh - $0/MWh = $9.74/MWh. East DC #1's net cost of serving its load is therefore 60 MWh x ($45.81/MWh - $9.74/MWh) = $36.07/MWh, very close to the $34.30/MWh day-ahead LBMP price at Bus B. (It exceeds the day-ahead LBMP price at Bus B because there are two components to differences in LBMP prices: differences in congestion costs and differences in the cost of marginal losses. While East DC #1 owns enough TCCs to insulate it completely from exposure to congestion costs for its 60 MWh load, TCC owners remain responsible for paying the cost of marginal losses. The marginal cost of losses in the Eastern zone is $1.77/MWh higher than at Bus B in this example, causing East DC #1 to pay $1.77/MWh more for the energy it consumes than it would have paid to purchase energy at Bus B.)[28] Thus, apart from the payment for marginal losses, the TCC provides a perfect hedge in this example for the congestion cost component of the LBMPs.

When a party's day-ahead schedule differs from its quantity in the balancing market, the TCC will not be a perfect hedge, but it nonetheless serves to hedge the day-ahead schedule. This

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28 Transmission-only customers can also hedge themselves against congestion costs by using TCCs. Appendix A also includes an example of a 25 MW bilateral contract between the North IPP, located at Bus L, and the Southeast DC, located at Bus V (in the Eastern zone). North IPP, which is responsible for paying the cost of transmission between Bus L and Bus V, owns 25 MW of TCCs from Bus L to Bus V, which enable it to ensure that its only cost to transmit

is illustrated in the two-settlement system examples in Appendix A. In the example, East DC #1 schedules the purchase of 70 MWh in the day-ahead dispatch. It pays $45.81/MWh, the day-ahead LBMP for the zone in which it is located (the Eastern zone), for this 70 MWh. (Part of this cost is offset by its ownership of TCCs, as discussed previously.) The appendix contains several different scenarios for balancing dispatches. In Balancing Dispatch Scenario 2, several loads in the Eastern zone consume more energy that they had purchased in the day-ahead dispatch. As a result, some high-cost units in the Eastern zone that had not been scheduled to operate are actually dispatched in the balancing dispatch, making the Eastern zonal LBMP increase to $71.25/MWh, well above the $45.81/MWh balancing dispatch zonal LBMP. East DC #1 is among the loads whose actual consumption exceeds its scheduled consumption, as it actually consumes 85 MWh. It would be charged the Eastern zonal balancing dispatch LBMP of $71.25/MWh for the 15 MWh whose consumption had not been scheduled a day ahead.

In other words, by scheduling injections and withdrawals matching its TCC in the day-ahead dispatch, the TCC holder (in combination with an energy trading partner) obtains dispatch commitments for these injections and withdrawals in the real-time dispatch. Because the congestion rents payable to the TCC holder offset the congestion costs between the injection and withdrawal points, the TCC holder pays no congestion component in its transmission price--only marginal losses and the TSC. The dispatch commitments entitle it to inject and withdraw the scheduled power at no additional cost in real time with deviations from the schedule settled at the balancing market prices. Thinking of it in this way, a party that submits a balanced schedule

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power (other than the cost of purchasing the TCCs) will be due to differences in the cost of marginal losses between Bus L and the Eastern Zone.

corresponding to a TCC that it holds accomplishes two transactions--both of which effectively are transmission transactions. By submitting the balanced power schedule, the party is buying transmission a day ahead and by settling its TCC, the party is selling the same transmission. This pair of transactions clearly net to zero because they are settled at the same transmission price. Accordingly, a TCC acts a perfect hedge for a corresponding balanced schedule of power transactions.

Alternatively, TCCs can be used in other ways. For example, TCC holders that do not schedule a matching set of injections and withdrawals in the day-ahead dispatch effectively would release that transmission capability for reconfiguration and sale to others in the day-ahead market and would receive the congestion rents when the TCC is settled in the day-ahead market. So, holding a TCC without a day-ahead schedule is equivalent to selling transmission in the day-ahead market. Likewise, TCC holders that schedule injections and withdrawals matching their TCCs in the day-ahead market but who schedule no injections or withdrawals in the balancing market effectively release that transmission capability for sale to others in the balancing market and would receive the difference in locational prices associated with their dispatch commitments in the real-time market. So, holding a TCC, entering a corresponding day-ahead schedule and then not dispatching in real time is equivalent to selling transmission in the hourly balancing market.

The reasoning from the ISO's perspective is the same as that previously discussed from the scheduling party's perspective, except that the role is reversed from transmission customer to that of the transmission provider. That is, when the ISO settles a TCC, it is effectively buying transmission service. Conversely, when the ISO accepts a set of schedules in the day-ahead market, it is effectively selling transmission service. In particular, the ISO aggregates all day-ahead schedules, whether they are individually balanced or not, and designs an overall balanced schedule. This aggregate balanced schedule is equivalent to the ISO selling a simultaneously feasible set of claims for point-to-point transmission services. From the ISO's perspective, assuming it settles TCCs at the first settlement prices, it effectively would sell transmission at these day-ahead prices when it accepts the day-ahead schedule and it would buy transmission from the TCC holders at the same day-ahead prices. By using the same spot transmission prices for both the buying and selling, the ISO generally will clear its account.[29]

Some have suggested that the ISO should both make day-ahead commitments and settle the TCCs at the balancing market prices. Although this idea may have some initial appeal, it would create an inherent contradiction. Specifically, the TCCs are a complete set of claims for using the transmission system. Likewise, the day-ahead schedules become dispatch commitments and represent a second complete set of claims for using the transmission system. Under the first settlement of a two-settlement approach, the TCC claims are extinguished at the time of the day-ahead auction and replaced by a follow-on set of dispatch commitments. In contrast, if both TCCs and dispatch rights were settled in the balancing market, the TCC claims and the dispatch-right claims effectively would co-exist during the period between the day-ahead and hourly markets. Such an idea cannot be made to work without imposing unacceptable financial risks on the ISO.

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29 In some instances, the ISO may receive some revenue despite the fact that it effectively has bought and sold transmission at the same prices. This has to do with the revenue adequacy issues that I have discussed elsewhere. Basically, the ISO can receive excess revenue either because it does not have to buy as much transmission as it sold (the TCCs did not exhaust the feasible capacity of the grid) or because some of the transmission that it does buy is not as valuable as other transmission it was able to sell in the day-ahead spot market (the transmission constraints may shift between the time of the 6-month TCC auction and the day-ahead market indicating that market value has shifted as well). This excess revenue would be not be retained by the ISO, but would be used to reduce the TSC.

That is, if TCCs were settled at the second settlement prices in the balancing market, the ISO effectively would be required to sell transmission at the day-ahead prices and then to buy it back by settling TCCs at the balancing prices. If the balancing prices reflect more transmission congestion than was anticipated in the day-ahead market, transmission prices will be higher and the ISO would incur a financial loss by having to buy transmission (i.e., settle TCCs) at a higher price than the previous day's selling price. Such a requirement clearly places an unacceptable financial risk on the ISO since it would have no good way to hedge or control unexpected price changes that will occur between the day-ahead and hourly markets as a routine matter.[30]

Overall, the proposed two-settlement system will promote economic efficiency in several ways. First, the scheduled use of the transmission system effectively is arranged so as to achieve the lowest bid-in costs. In contrast, a system based solely on private trading of *physical* rights is unlikely to identify all efficient trades when the transmission system is constrained. Second, the two-settlement system provides an incentive for parties to participate in the day-ahead market since it creates an ability to lock-in prices for the day-ahead period. The day-ahead market will be useful for LSEs that have the ability to respond to prices with some lead time. They may bid flexibly into the day-ahead market and, if they do not bid high enough and their load is not scheduled, they will have 24 hours to make changes to their real-time operations (e.g., sending a shift home). If they are scheduled, they will have "locked-in" a price that they are willing to pay. Similarly, a generator bidding into the day-ahead market will be scheduled only if market prices

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30 Such an arrangement also would create opportunities for strategic manipulation whereby a party could withhold information from the day-ahead market in order to induce a particular price change in the dispatch market that would be favorable to its position. Clearly, this would be an unacceptable basis for a neutral market facilitator, such as the proposed ISO.

equal or exceed its bid cost. Hence, by bidding into the day-ahead market the generator can learn whether it will be economic for it to pay the costs to bring its plant on-line for the following day. If it is economic to do so, the generator is scheduled and locks in to a price that equals or exceeds its bid costs. In addition, the day-ahead energy market would be compatible with the operation of natural gas markets, an important consideration for gas-fired generators.

Finally, the collaborative discussions in New York also have considered a possible three-settlement system that would provide for an additional settlement an hour before the actual dispatch. An additional set of deadlines would be established for accepting bids into the hour-ahead settlement and for posting the hour-ahead LBMPs. Rules would also need to be written to describe how the hour-ahead settlement would be integrated with the day-ahead and balancing markets. The rules that would be consistent with the two-settlement system would allow parties to carry dispatch commitments from the day-ahead market forward into an hour-ahead market, where they would be settled based on the prices and quantities determined in the hour-ahead market. The resulting dispatch commitments made in the hour-ahead market would, in turn, carry forward into the balancing market and would be settled based on balancing market prices and quantities. An important consideration in designing such a system is that the centralized settlement process, i.e., the process for determining dispatch quantities and locational prices, should be consistent between the three markets.

Assuming that the three-settlement system operated according to this description, the principle features that promote economic efficiency are the same for both the two- and three-settlement systems so my basic assessment would be the same for either approach. The decision about whether to proceed with the third settlement could, therefore, be based on an evaluation of commercial costs and benefits. The costs of such a system include the one-time expenses of developing the software and the on-going operating costs of running the third settlement. The benefits are the value that market participants may place on having the option to lock-in prices an hour before the dispatch, which depends on the timing and rules of neighboring electricity markets and gas markets. A reassuring point is that a third settlement can be viewed as an addition to, rather than a fundamental alteration of, the proposed two-settlement system so that if it is not included in the initial software implementation, it most likely could be added at a later date.

D. Transmission Service Charges and Transmission Congestion Contracts

The need for TSCs arises because the congestion revenues and marginal loss charges collected by the ISO from grid use would 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 total congestion-related revenues arising from short-term opportunity cost pricing of transmission typically will 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 applies to all grid users that recovers the remaining embedded costs of the transmission grid.

Separate TSCs for each utility means that customers located in different parts of the state may pay a different TSC for transmission service. The Proposal adopts this approach in order to avoid cost-shifting between and among the New York utilities. To attempt to change the existing allocation among the IOUs of the statewide transmission revenue requirement as a part of competitive restructuring would result in immediate cost-shifting in which case some loads would pay more and some would pay less than their historical share of statewide transmission costs. This would greatly complicate the transition to a statewide tariff. The utility-based TSC avoids such cost shifting.

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. 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 necessarily 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 TCCs are financial obligations. The holder of a TCC from point A to point B is obligated to receive a payment equal to the congestion rents between the two points, which is the price at point B minus that at point A adjusted for marginal losses. If the congestion rent is positive, the TCC holder receives a payment from the ISO, which is the most likely circumstance. However, if the congestion rent is negative, the TCC holder is obligated to make the indicated payment to the

ISO.[31] The reason for making TCCs obligations is that it is a straightforward way of defining[32] financial rights to the full capacity of the transmission system that can be carried forward from the 6-month TCC auction to the day-ahead first settlement.

Externalities and Loop Flow

The ISO'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 parallel or loop flow effect 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, the loop flow effects would result in shifts in cost responsibility, because loop flow can create externally imposed costs, such as out-of-merit generation, 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, which is inherent in a free-flowing network. The free-flowing New York electric grid is an asset that for reliability reasons should be preserved, not abandoned, in the transition to a more competitive electricity market.

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31 If the TCC holder, together with its energy trading partner, effectively schedules a balanced power transaction that corresponds to its TCC, the payments made to the ISO for spot transmission service will exactly offset the receipts from the ISO for payment of the congestion rentals associated with the TCC, even when the congestion rent is negative.

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Theoretically, property rights for the capacity of 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 such 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.[33]

Under the Proposal, the ISO's central coordination will deal efficiently with the externalities caused by loop flow.[34] Using locational prices derived from market participants' voluntary price offers the ISO will coordinate an efficient allocation of the costs of transactions to those responsible for those costs. In addition, ISO will administer a system of transmission rights (TCCs) that will efficiently allocate scarce transmission and appropriately compensate TCC holders.

Financial Versus Physical Rights

The TCCs have an advantage over alternative definitions of firm transmission service in that they are financial rights that can be traded without affecting in any way the ISO's determination of the

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33 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).

34 That is, the New York ISO can deal with parallel flows that would occur within the New York grid in the absence of an ISO. Of course, a New York ISO by itself cannot deal with regional loop flow beyond the boundaries of New York.

units to commit a day-ahead or the energy to dispatch within the hour. In contrast, a system based on strictly physical transmission rights would rely on bilateral or *ad hoc* multi-lateral trading of the transmission rights in order to achieve an hourly dispatch. In practice, it could be difficult, if not impossible, for private parties to trade physical transmission rights in a way that economizes on fuel and start-up costs. This is because of strong network interactions that complicate the trading of physical rights. As illustrated in Appendix F, these interactions affect the degree to which capacity between one pair of locations can be substituted for capacity between another locational pair without violating the reliability constraints. As a result, it is not generally possible to substitute capacity on a one-for-one basis between grid locations. And since these network interactions themselves change as grid usage changes, it would be very difficult for sequential trading of bilateral physical rights to result in a reconfigured set of rights that exhausted the aggregate capacity of the grid as a whole. Some rights would be left on the table. This means that decentralized, independent, private trading of physical transmission rights is likely to leave many efficient deals unconsummated because the parties will not be able to identify all trading opportunities without an intermediary that can combine knowledge of the current network interactions with information about the parties' willingness to pay.

By contrast, TCCs and the day-ahead market conducted through the PEs and administered by the ISO effectively provide the intermediary service that solves this problem. The scheduled LBMP from the day-ahead market can be thought of as finding a configuration of spot transmission usage that best accommodates the bid-in preferences of the market participants in the aggregate. This pattern of spot transmission usage will differ from the pattern associated with the

TCCs, which were obtained from past TCC auctions or grandfathered rights. The ISO is able to ensure any party willing to hold its transmission rights as a TCC that it, the ISO, can find a spot usage of the transmission corresponding to the party's TCC that is at least as valuable or more valuable than the party could find on its own. It does this, in effect, by finding multi-lateral trading opportunities that are inherent in the centralized day-ahead market.

Transmission Obligations versus Transmission Options

The obligatory nature of the TCCs simplifies the computation of engineering feasibility that any system of transmission rights must possess. An alternative would be to define transmission rights that would give the holder the option to schedule a power transfer or to receive financial compensation. Such a right would be in effect a TCC option, in contrast to a TCC which obligates the holder. The TCCs will be revenue adequate whenever the total congestion payments made to the ISO equal or exceed the congestion payments required for the holders of the TCCs. For the case of the TCC obligations, the simple test is the simultaneous feasibility of the TCCs, a test equivalent to that applied to point-to-point reservations.[35] To determine the revenue adequacy of a set of transmission rights that includes both TCC options and obligations, however, the resulting network of TCC options and obligations must be tested for all possible combinations of how parties might choose to exercise their options. Practical complications associated with this type of computational test currently would prevent it from being fully implemented in the time

[35] 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).

frame of the Transmission Providers' Proposal, but it might be possible to accommodate in the future.[36]

I recognize that the current industry practice is based on transmission service that is optional (in the sense that a firm transmission customer currently would not be obligated to actually use or sell the service) and that TCCs may be perceived as a substantial departure. Nonetheless, the industry is not likely to be able to move forward into a competitive environment with its previous transmission practices, in my view. First, the amount of unbundled transmission service in use today (almost all of which gives the customer the option of not using the service in its contract) is much smaller than the amount that will be used in tomorrow's market, especially if retail choice becomes a reality. Now, transmission service in support of native load can absorb almost all of the burden when optional use of the transmission service stresses the grid. That is, utilities today frequently redispatch their systems (the increased fuel costs of which are paid by native load) to relieve potential transmission overload problems, many of which may be caused, in whole or in part, by loop flow from optional wholesale transactions. Soon, the retail load will add to this problem and will not be available to absorb such stress. Second, utilities are currently willing to redispatch when loop flow creates a constraint on their systems and they generally defer to one another when claims are made that service is not available because it must be held in reserve for retail users. While these practices have been adequate in the past, competition will change this. Third, it is important to consider that under current industry practice firm

[36] Pre-existing transmission contracts that are not converted to TCCs (Modified Wheeling Arrangements) are physical options contracts and must be accommodated under the proposal. This limited use of options can be implemented with some probably small effects on revenue adequacy; however, a more general availability of options could not be handled using existing software.

transmission service is not only optional on the part of the customer, but also is interruptible on the part of the utility. In the future, the market will be less tolerant of such interruptions and will demand that greater certainty be given that firm service is indeed firm. The way to do this for the obligation type of TCC is clear, but remains to be worked out for TCC options.

If the industry makes optional transmission service available, a way must be found to check for feasibility that is acceptable to all parties. Due to the effects of counterflow on the system, it is almost certainly the case that the number of options that can be held while maintaining reliability would be less, perhaps substantially so, than the number of obligation TCCs.[37] In itself, this is not a problem, since a MW of a TCC option may be more valuable than a MW of an obligation TCC. Ideally, the industry would offer both options and obligations and let the market decide.

A further argument in favor of obligation TCCs is that they can accommodate retail competition as readily as wholesale competition. The TCC options, on the other hand, cannot be managed in the context of retail competition without substantial additional work. For example, assessing the engineering feasibility of obligation TCCs is equally easy regardless of the number of such TCCs. In contrast, the difficulty in assessing feasibility increases dramatically with the number of optional TCCs because all possible combinations of their potential use must be examined.

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37 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).

Finally, and perhaps most importantly, an obligation TCC from location A to location B can be decomposed so as to go through an intermediate location without changing its economic value. For example, an A-to-B TCC obligation could be converted into two TCCs obligations--one from A to intermediate location Z, and another from that intermediate location Z to the final destination B. The value of the two TCCs (A-to-Z and Z-to-B) will always equal that of the original TCC (A-to-B) because each TCC is an obligation that must be met regardless of whether the economic value of the congestion is positive or negative between any pairs of locations. This decomposition would facilitate the creation of market hubs, with TCCs reconfigured automatically as being to-and-from the hub. In contrast, this type of decomposition cannot be arranged for TCC options, because the economic value at the intermediate point Z may not itself be intermediate to the economic value at the source and destination locations. In such a case, the value of the original TCC would be increased by dividing it into two parts with both treated as options, since the holder of this new option would have more options and a greater ability to avoid negative congestion rentals. Obligation TCCs can provide a bridge that can accommodate either retail or wholesale competition, as policymakers decide these matters in the next few years. A system to provide TCC options on a basis consistent with competition could be designed when it is needed in the future.

Transmission Expansion Process

The availability of TCCs also should improve the transmission expansion process by making better information available to market participants and protecting investments in transmission upgrades. Under the New York 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 LBMPs and by the costs of upgrades. The role of planning and regulation would be narrower, addressing the unavoidable interactions in the transmission grid. To a greater extent than occurs today, investment 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 TCCs could provide price certainty for those that pay for the expansion without affecting the allocation of the existing transfer capability of the transmission grid.[38]

The efficiency benefits that flow from the use of locational pricing and TCCs can be illustrated by considering the limitations of a single-price electricity market, such as that utilized in England and Wales. 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 England and Wales, 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

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

particular grid expansions to those whose market activities will create the need for those expansions.[39]

These problems are alleviated under the New York 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 TCCs 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 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. TCCs 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 grid transmission capacity; in

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39 The British have partially mitigated this problem by giving NGC (the National Grid Company, the ISO 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

exchange, they should be able to reserve TCCs corresponding to the capacity associated with the expansion. These incremental TCCs would have no effect on the feasibility of previously allocated TCCs. Thus, those who reserve transmission service in this way would be granted rights to locational compensation offsetting any future congestion costs, thereby ensuring that transmission use by others would not deprive them of any benefits of the expansion.

Well-defined transmission rights in the form of TCCs are vital to the creation of a long-term transmission market. Without TCCs, 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 rents. 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 TCCs. The transmission owner, as a regulated monopoly, could build the lines in exchange for a payment that covers the capital cost and a regulated return. Under this arrangement, the consortium would

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reduction in uplift costs, but only by making the monopoly NGC/SO a larger player with its own commercial interests bear the financial risk since 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 ISO. The ISO, for example, would need to verify that the newly created TCCs would be feasible and consistent with the obligation to preserve the existing set of reserved 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 TCCs.

Despite the potentially 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 region-wide implications. This suggests a continued role for a regional transmission assessment, perhaps done by an ISO. For example, an ISO 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 but rather would be limited to the coordinating role of validating the new TCCs created by the expansion and the lack of

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in the market and increasing the importance of the regulatory formula that determines NGC's revenue and incentives.

degradation of existing TCCs. 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 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 would be able to agree to finance a grid expansion that appears to be beneficial for the system as a whole. As a backstop, an alternative regulatory method of approving and financing transmission investments could be necessary. Thus, any interested party could propose a project and an allocation of its costs among those grid users who would benefit, consistent with sections 211 and 212 of the Federal Power Act. Any proposed expansion also would have to meet the requirements of Article 7 of the New York Public Service Law.

Unregulated Financial Products and TCCs

The existence of TCCs as financial hedges would not preclude, and would likely facilitate, the development of a wide variety of unregulated financial products for transmission service. These possibilities are not addressed by the Proposal but could well emerge from the market. In particular, unregulated secondary markets for transmission service may coexist with and would likely be facilitated by the availability of TCCs which would provide firms that offer these services with a mechanism to hedge their risks. Such a product could be offered by any market participant and need not be regulated by FERC. Firms offering unregulated transmission hedges could acquire TCCs in the initial auction or from the secondary market and repackage these hedges for LSEs on any terms they found economically attractive. In a market with TCCs, unregulated providers of transmission hedges could offer a variety of hedges for combinations of injections and withdrawals. Operating as PEs, they could offer transmission service by nominating their customers' power into the grid and paying to the ISO 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.

While all transmission service purchased directly from the ISO would be priced on a spot basis (although potentially hedged by TCCs), 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 TCCs. Indeed, one can think of TCC ownership, rather than physical transmission asset ownership, as constituting the core assets of such unregulated transmission service providers.

E. Transmission Auction

The Proposal includes provisions to grandfather certain rights to use the transmission system that presently exist for certain contracts or certain facilities. This continuation of existing rights is a necessary feature for the transition, both as a matter of equity and to accelerate the movement to a more competitive market. Failure to honor such established rights would likely result in substantial delay in implementation of the proposal. However, these grandfathered rights apparently leave a certain amount of transmission capacity that can be made available for the market that goes beyond the requirements of Order 888 in that it not all the capacity that could be set aside under Order 888 will be subject to the grandfathering provisions. This available capacity must be allocated as TCCs.

The Proposal calls for a TCC auction every six months and longer-term TCCs for the existing may be made available as the market matures. These TCCs will be separate from any long-term TCCs created as a result of grid expansion, as discussed above. The TCC auction will offer financial contracts for transmission service that can be accommodated above that needed to honor certain pre-existing transmission contracts and own-load facilities reservations. TCCs that are available in excess of these grandfathered rights will be auctioned for each six-month winter and summer season. The proposed auction will have the objective of finding the highest valued set of bids for simultaneously feasible TCCs. As such, the auction determines a set of mutually consistent TCCs that creates the highest possible value for the auction participants as a whole.

The objective of the auction, then, is to allocate the available TCCs so as to promote economic efficiency. Such an auction differs in important ways from an ordinary auction of artifacts. The set of TCCs that will be auctioned, for example, need not be defined beforehand. This is because the amount of transmission obligations that can be sold in one direction partially depends on the amount sold in some other direction. So for example, if an additional 100 MWs of TCCs are sold from point A to point B, it could be the case that 50 fewer MWs could be sold from point C to point D. This type of network interaction means that many combinations of TCCs are feasible. Because of this, the auction needs to be structured so as to not pre-judge which pattern of TCCs might be preferred by customers, but instead to allow customers to decide this as part of the auction process itself. Accordingly, the auction will find the highest aggregate value over all potential holders of TCCs by assessing the tradeoffs between selling more obligations in one direction at the expense of selling fewer in another. Any initial allocation that does not address these strong network interactions would fall short of achieving the highest possible valuation of the transmission system as a whole. In effect, the proposed auction assesses multi-lateral tradeoffs among many combinations of point-to-point obligations in order to promote efficiency in the TCC allocation that is made every six months.

The proposed TCC auction will be conducted using computer software that performs an optimization similar to an optimal power flow. Such an approach will ensure that the collective set of TCCs awarded in the auction is simultaneously feasible when combined with the pre-existing transmission rights that have been grandfathered. The rules governing such an auction have not been determined at this time.[40] The Proposal indicates that the auction must be open to all eligible parties and conducted in a non-discriminatory manner.

F. Ancillary Services and Uplift

The treatment of ancillary services as procured largely from the market is consistent with the objectives of non-discrimination and competition. In the main, ancillary services would be joint products with energy and efficiency requires that the purchase of the services be coordinated with the dispatch. In addition, the location and character of ancillary services such as spinning reserve and reactive support may have a complex relation to the dispatch of energy both by location and for the changing configuration of generation. In executing the coordinated procurement of ancillary services, the ISO can purchase from any willing supplier at non-discriminatory prices. To the extent that the costs of the services cannot be directly attributed to individual customers at the margin, the costs would be joint and would be recovered through the various ancillary services payments spread across customers.

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40 Additional issues regarding potential ways of conducting a TCC auction are discussed in Appendix B.

In addition, the uplift would necessarily include other costs that could not be directly attributed, such as the cost of start up and minimum load in any cases where the market-clearing locational prices do not by themselves provide sufficient revenue for some generators. Importantly, the proposed uplift component would be no larger than it must be in order to recover the minimum generation and start-up costs that the LBMPs cannot recover on a per-unit basis. That is, on those occasions when the LBMPs alone can support an efficient dispatch with sufficient margin to cover each generator's start-up costs, the ISO's uplift for minimum generation and these costs will be zero. In such circumstances, there would be no generator that the ISO had decided to leave out of the day-ahead schedule that has a combination of start-up and running costs that would reduce the overall costs of the unit commitment and dispatch. If such a generator existed, the ISO would have scheduled it in the day-ahead market in the first place. In addition, all generators with minimum generation and start-up costs that the ISO decided to include in the day-ahead schedule earn sufficient margin so that no such generator needs an additional payment that would need to be financed through an uplift charge. So, if an efficient solution can be found to the unit commitment problem that does not entail additional payments for fixed costs to any generator, the ISO will calculate a zero charge for this portion of the uplift under the Proposal. However, if the lowest cost solution reduced the market-clearing prices enough, it might result in a condition where the revenue could not cover all the costs of the generators with startup and minimum load costs. In these circumstances, no single energy price would be sufficient to support the least-cost solution and, exactly under these circumstances, some second payment must be made. Consequently, the proposed uplift is not expected to be any larger than it must be in order to promote the efficient solution to the unit commitment problem precisely when the unit commitment problem exhibits the special characteristics that require coordination through the ISO.

IV. THE PROPOSED SYSTEM MEETS FERC'S OBJECTIVES

The proposed system satisfies the Commission's objectives set out in Order 888, the Transmission Pricing Policy Statement, and other orders.[41]

A. The Proposal Provides Comparable Service

The Proposal provides for comparable service because all parties pay for transmission on the same basis and the non-price terms and conditions are the same for all parties. Under the LBMP pricing method, the price of transmission between any two locations on the New York grid at any point in time is the difference in the LBMP prices between the sending bus and the receiving zone, 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 access charges as users operating through the ISO's economic dispatch. Consequently, the proposed system of congestion pricing and access charges treats all parties identically.

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41 I believe that the Transmission Providers' proposal also is consistent with the guidance provided by the New York Public Service Commission in its May 20, 1996 Opinion and Order in Case 94-E-0952 to implement a "flexible poolco".

The initial allocation of transmission rights is based on existing contractual obligations and native load obligations. This approach intentionally treats parties differently, but the proposed treatment is consistent with the Commission's decision to respect existing contracts in Order 888.

B. The Proposal Has No Pancaking

The Proposal does not involve pancaked transmission rates since any party may obtain state-wide transmission service between any two points on the New York grid at a statewide price. An eligible customer pays a single TSC, not multiple TSCs. The customer pays the TSC of the utility associated with the customer's transmission district. That is, the transmission district serves to identify which utility provides transmission service to a particular customer. In addition, a single tariff for ancillary services is available statewide.

C. The Proposal Is Consistent with the CRT NOPR

The proposed system establishes clearly defined point-to-point transmission rights in the form of tradable financial obligations. The Proposal is quite consistent with the Commission's CRT NOPR.[42] Features of the Transmission Providers' Proposal that are consistent with the Commission's Proposed Rule include:

- Transmission service is defined as flexible point-to-point service
- The service is tradable in a secondary market thereby allowing parties to arrange efficiency-enhancing trades

- Service feasibility is evaluated using the single standard that all scheduled use of capacity reservations must be simultaneously feasible

- Capacity reservations can be used to deliver any type of power product, such as firm or non-firm power

- Reservations may be modified on an as-available basis as long as the reservations held by others are not degraded

- Opportunity cost pricing is implemented by a system of congestion pricing

- A holder of a reservation does not pay congestion costs (in the sense that any congestion charges paid are rebated), while a party not holding a reservation pays the congestion charge

In sum, the Transmission Providers' Proposal should be viewed by the Commission as a transmission tariff that goes beyond the Order 888 *pro forma* tariff to offer the type of transmission service envisioned in the CRT NOPR.

D. The Proposal Is Consistent With The Commission's Transmission Pricing Policy

The Proposal is consistent with the Commission's transmission pricing policy both in its strict interpretation and the spirit of the policy in promoting open access and efficient pricing.

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42 Federal Energy Regulatory Commission, "Capacity Reservation Open Access Transmission Tariffs," Notice of Proposed Rulemaking, RM96-11-000, Washington DC, April 24, 1996.

The Proposal Is Not "And" Pricing

The Proposal also does not involve "and" pricing. First, no transmission owner collects more than its cost of service since all transmission congestion rentals are paid out to holders of TCCs and any payments of excess rentals to a transmission owner are used to reduce that owner's TSC. Each transmission owner will recover its cost of service partly through Transmission Service Charges (TSCs) paid by load-serving entities and partly through the revenues from the TCC auction. Each transmission owner's TSC will be set so as to recover its cost of service less (1) the revenue earned in the TCC auction, (2) any congestion rents not directly assigned to TCC holders, and (3) the difference between marginal and average losses.

Second, no customer will be charged both for a TCC and for transmission congestion. Once a TCC has been paid for, the holder is entitled to be paid the congestion rental, even if the holder decides not to schedule the associated power transaction.

Third, no customer will pay two prices for the same transmission service. All customers, however, will pay the TSC as an access fee. The payment of this fee entitles the customer, as a general matter, to access when the grid is uncongested, but it does not entitle the customer to access during congested periods between particular locations. To obtain access to the higher quality of service rendered by the grid during congested periods, the customer must pay a higher price. It is appropriate for a customer to pay an overall bill that has two parts--a fixed fee for non-congested service plus the market clearing price for the higher quality service during congested times.

Fourth, it is important to recognize that the access fee basically covers only that portion of the revenue requirement that cannot be collected from the auction of the TCCs. In this sense, the proposed TSC does not correspond exactly to the embedded cost pricing concept used by the Commission in its "or" policy. The adjustment of the revenue requirement for the TCC auction proceeds means that the combination of the TSC and the congestion price should more or less equal the revenue requirement. No over-recovery is involved.

In addition, the Commission's intent with its "or" pricing policy is to promote an efficient equilibrium in which customers will have an incentive to invest in additional transmission facilities to the extent justified by the congestion charges or opportunity costs. The Transmission Providers' Proposal is designed to promote this long-run outcome. This is because of two equilibrating mechanisms that can work in conjunction with the Proposal. First, the revenues from the TCC auction will tend to equal expected congestion costs, as a general matter, since the primary value to holding a TCC is the congestion rentals to be received. Second, if congestion increases in the future to the point where average congestion costs equals the incremental cost of expansion, the TCC auction then will tend to yield revenues that will approximate incremental expansion costs.[43] In such a case, the access fee would be used to collect only the difference between average grid costs and the incremental expansion costs since TCC revenues are subtracted from the revenue requirement recovered by the access charge. Consequently, the Proposal is consistent with the Commission's policy of promoting an efficient comparison between opportunity costs and expansion costs with the added feature that it incorporates a

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43 This is a hypothetical circumstance that may or may not materialize in the future. Currently, congestion rentals are expected to recover only a small fraction of the aggregate New York transmission revenue requirement.

method for recovering that portion of the revenue requirement that marginal cost pricing (as determined by an auction mechanism) cannot recover.

The Proposal Adapts the Commission's Policy to a Restructured Electricity Market

The above arguments summarize why I have consistently maintained that a transmission pricing system based on access charges for capital recovery of net fixed costs and congestion pricing for short-run capacity allocation, with compensation to TCC holders to cover their increased energy cost at the margin caused by the implicit sale of their transmission reservation, does not constitute "and" pricing.

The Commission's policy was crafted in the context of a substantially different structure for the electricity market. The Proposal here takes the foundation of the Commission's policy for open access and efficient pricing and adapts it to a dramatically restructured electricity market that goes much further in the direction established by the Commission. Others, however, may urge the Commission to take a different view and extend the Commission's prohibition against "and" pricing in ways that could result in substantial inefficiencies. In particular, the Commission may need to address the argument that would allege that an access charge is payment for access at any time, not just during uncongested periods, and that charging both a TSC and a congestion price to a transmission customer that does not have a TCC is a form of "and" pricing. In dealing with such an argument, I encourage the Commission to consider the possibility that there could be good versions of "and" pricing and bad versions of "or" pricing in the new context of an ISO and a fundamentally restructured energy market.

A good version of "and" pricing is one that recovers net fixed investment costs through a fixed charge that does not influence customers' usage decisions, while recovering opportunity costs through a per-unit price on usage. The Transmission Providers' Proposal has this character. The access charge is not recovered in any way that influences grid usage decisions, while grid usage is priced on a per-unit basis in a way that is no higher than needed to clear the market.

In addition to recognizing the literal compliance with the Commission's policy, it is important that the Commission evaluate this Proposal in the context of the changed circumstances in the industry. In the new ISO context, the access fee and congestion charges will be charged to all users, including load-serving entities on behalf of retail load. Previously, the Commission had evaluated transmission pricing proposals for "and" pricing for unbundled transmission customers only, with native load paying for residual revenue requirements. A fresh review is appropriate in this case since the previous distinction between unbundled wholesale transmission customers and native load is no longer applicable, and all customers are treated the same. As a result, at least some of the Commission's previously expressed concerns do not apply to the Proposal. In previous cases, the Commission stated that "and" pricing would benefit native load at the expense of unbundled wholesale transmission customers by recovering more than was needed to hold the native load harmless. Basically, the concern was that one customer class, unbundled wholesale transmission customers, would be charged two prices (so-called double dipping), while another customer class, native load, only would be charged a single price. Such a concern is clearly absent is this Proposal. The combination of the access charge for net fixed costs and the congestion charge is applied to all transmission customer classes, including the retail load of load-serving entities.

A second changed circumstance is that the Commission's previous reviews of "and" pricing involved traditional transmission pricing for which both fixed investment costs and opportunity costs were recovered on a per-unit wholesale transmission basis. Because of this, the Commission correctly concluded in its previous reviews that charging for both embedded costs and opportunity costs would lead to inefficient outcomes. This would occur because the customer would compare its per-unit usage price that included both embedded costs and opportunity costs to the utility's per-unit price that consisted of only opportunity costs, since its fixed costs were recovered through native load rates that were irrelevant to the utility's wholesale trading opportunities. This previous difference in the per-unit basis of the two rates could have caused inefficient choices as the Commission has noted. This fundamental circumstance is now changed in the Transmission Providers' Proposal. All per-unit prices for transmission in the day-ahead market are based on congestion costs only--no fixed investment cost recovery is at stake.[44] The Commission's prior concern about inefficiencies caused by "and" pricing are resolved in the Transmission Providers' approach.

Misapplication of the Commission's Policy Could Create Inefficiency and Discrimination

A wrong application of the Commission's policy to the changed market could contravene the Commission's own intent, creating inefficient pricing and violating the principle of comparability.

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[44] The Transmission Service Charge may be converted to a per-unit charge or load for billing purposes, but will not depend on transmission usage or the source of the power.

It is possible to formulate a bad version of "or" pricing. One way to do this might be to force fit the "or" approach into the congestion pricing framework of an ISO. Before I construct such a straw man, I'll briefly review the Commission's approach so that the reader understands the portion of the Commission's policy that I believe cannot be readily transferred to the ISO context.

Under its "or" pricing policy applied to opportunity cost, the Commission has previously allowed a utility to charge the higher of an embedded cost price or the opportunity cost price. For non-firm service, the comparison of the two prices was made on an hourly basis. For firm service, the comparison was made over a time period that could be as long as a year. This extended comparison was made by accumulating the total payments due under the embedded cost rate, and separately under the opportunity cost rate, and then charging a rate that ensures that the customer pays no more than the higher of these two accumulated totals.

Regardless of the merits of such an approach in the past, it clearly cannot be made to work in the congestion pricing context of the New York Proposal. The reason is that it would not be possible to determine the higher of embedded cost and congestion cost without first converting the embedded-cost access charge into a per-unit charge between locations. Such an approach would mean that the recovery of fixed transmission costs would influence and distort decisions about how the grid is used in support of the daily energy markets, which would be a source of major inefficiencies.

The market clearing congestion charge is a market-driven price that is determined so that all traders having a willingness to pay less than that price do not receive service. If some of those traders could claim to have already paid for congestion because of having paid the access charge

(TSC), they would not be willing to get off the system despite the fact that they value the service less than the market clearing price. Their continued presence on the system would serve to bid up the congestion price to a higher market-clearing level. The precise equilibrium that would result from such "or" pricing would depend on how the policy were implemented, but it would be an inefficient equilibrium in any event.

Two features of the proposal would be exceptionally difficult to reconcile with a strict version of "or" pricing that would require comparing the TSC with the congestion costs. These two features are the different settlement procedures for bilateral trade versus central market trade, and the differences in the utilities' TSCs. Before explaining the difficulties in each instance, imagine first that all trade is settled in precisely the same way, and that a uniform TSC prevails. In this counterfactual circumstance, a required comparison of the TSC and congestion costs may result in an acceptable outcome, but it would not further any of the Commission's goals either. This is because the required comparison of each hour's TSC payment with congestion prices would mean that no potential transaction would be voluntarily withdrawn from the transmission system at any congestion price less than the TSC, since the party to the transaction would not pay any additional costs until the congestion price exceeds the TSC. As a result, traders would bid up congestion prices to the point where the market would clear at a level that approximated the sum the TSC and the congestion cost, thereby defeating the intent of the policy to begin with. A well-implemented version of such a policy might be a benign, although circuitous, approach to recovering both embedded costs and congestion costs in a single price.

In practice, however, the effect of a required comparison of the TSC and congestion costs would severely disrupt the market. First, congestion prices are settled differently for bilateral transactions and commercial arrangements made through a PE. Bilateral transactions pay an explicitly congestion cost component in the transmission usage charge. The congestion cost is implicit in the LBMPs paid by the PEs, however. Only the explicit payment of congestion costs by bilaterals could be subjected to a TSC comparison requirement -- the implicit payment of congestion costs under the central market settlement system could not be treated in the same way, since there is no congestion cost price that could be used in such a comparison. As a result, this type of "or" pricing would work to the advantage of bilateral transactions since the transmission price necessarily would be smaller for bilateral arrangements than it would be for central market arrangements. Such a policy would artificially and heavily skew the market in favor of bilateral deals and would undermine the viability of the centrally-coordinated markets. These markets are at the heart of the Proposal and are the source of the efficiencies that can be created when the two forms of trade are treated comparably. For the restructured market, such a perverse adaptation of "or" pricing would make the pricing rule violate the comparability standard.

A second complication is the uneven TSCs paid by parties in various parts of New York. Parties paying a high TSC would be willing to bid higher for congested transmission service than others since they would not pay any more in actuality until the congestion charge exceeds their high access charge. A simple example can show the possible inefficiency. Suppose customer A is imputed to pay a per-unit access charge of 10 (which is the hourly portion of the customer's annual fixed access charge on a pro-rata basis) as a result the calculations that might be suggested by some in implementing the FERC "or" policy. In addition, customer A has value of 2 associated with using the grid during this hour. Another customer B pays an imputed per-unit access charge of 5, but values this hour's service at 7. Suppose that both cannot be accommodated. Customer A can bid the congestion price up to 10 without paying anything more than it already must pay as part of its access charge obligation. So, the equilibrium would be one in which customer A outbids B, who would be limited to a bid of 6. The market clearing congestion price would be represented by customer A bidding 7 (say), and the outcome would be inefficient. Customer A with a current value of 2 nonetheless would bid 7 and receive the service in favor of customer B who has a current value of 6, but who cannot bid enough to overcome the preference given to A's access charge. In these circumstances, A pays its access charge of 10 and wins the congestion auction by paying nothing, while B continues to pay its access charge of 5 as the loser in the auction. Nothing would be gained by conducting such an auction. The basic purpose of the auction to promote efficiency by ensuring that those with the highest willingness to pay receive service is not attainable by an "or" policy in the presence of unequal access charges.

It would be an impossible task to design an "or" pricing policy that compares embedded costs and congestion costs directly without undermining the determination of the market-clearing congestion charges to begin with. In other words, the old one-part transmission pricing rule would be inconsistent with a bid-based economic dispatch that stands at the center of a restructured, competitive electricity market. The best way to design rates in these circumstances would be to separate the mechanisms used to recover long-run investment costs from those used to determine the value of short-run congestion costs. The Transmission Providers' Proposal does this in a way that is consistent with the Commission's policy. The fact that the two types of prices have been separated in order to promote efficiency should not be interpreted as an impermissible form of "and" pricing.

To summarize, I do not view a system that has separate mechanisms for net investment cost recovery and opportunity cost pricing for implicit transmission trades as constituting impermissible "and" pricing. Quite the opposite; such a separation can promote the public interest if designed properly, as I believe to be the case under the New York Proposal. In contrast, it is possible to construct hypothetical versions of so-called "or" pricing that would not serve the public interest well. In deciding such issues, in addition to recognizing the basic consistency with the Commission's policy, the Commission can return to first principles, such as those enunciated in its Transmission Pricing Policy Statement, and avoid the simplistic argument that a pricing proposal is unacceptable merely because it includes two cost components.

V. OTHER ISSUES

A. Uniform Pricing Alternative to Locational Pricing

The principal alternative to the locational pricing embodied in the New York proposal would be some form of uniform pricing of power over the ISO's grid. This is the approach adopted in England and Wales. This alternative is evaluated in Appendix E. Such an approach will lead to substantial inefficiencies when grid congestion is large and important. For example, I understand that the Central-East interface within New York is frequently constrained and that the associated differences in marginal costs are substantial. This suggests that it is important to find a way of dealing with transmission constraints and rationing transmission use when they are binding. There are two ways to do this -- price rationing or non-price rationing. Price rationing is the efficient way to deal with the scarcity of transmission, just as it is for any scarce economic resource. And, a system of price rationing for transmission is nothing more than the congestion pricing of the New York Proposal. In contrast, non-price rationing would lead to several inefficiencies, depending on how it might be implemented. The lessons learned from the experience in England and Wales, as well as other potential inefficient consequences are discussed in Appendix E.

B. Economic Curtailment

Situations may arise in which the ISO could be unable to find feasible security-constrained dispatch based on flexible bids. This could occur because of contingencies, such as generator or line outages or because market participants have provided fixed schedules that cannot be simultaneously honored, even under normal operating conditions. To the extent possible, load shedding and generation curtailment should be accomplished in an economic manner. In the case of generation curtailment, this could be done through a system of bids submitted by generators indicating their willingness to be curtailed. These bids could be negative, in which case they would indicate the generator's willingness to pay not to be curtailed. The ISO would use these bids in its economic dispatch to select the generators to be curtailed. The curtailment would reflect the effect of generators at different locations on the loading of a particular transmission line. The ISO would choose generators to curtail so as to relieve the over-load condition at the least-cost.

Similarly, when end-use customers, especially large industrial customers, have the appropriate metering and communications equipment, economic efficiency would be promoted to the extent that load could be shed in the most economical manner. The ISO could help to coordinate such economical load shedding by accepting positive bids for customers indicating their willingness to be paid to be curtailed.

The details of how to accommodate these bids in the economic dispatch has not yet been worked out.

C. Sequential Auction

The New York proposal does not include any details on how the auction of TCCs would be conducted. This is an issue that will be addressed in the future discussions among the parties. The auction of TCCs can be substantially more complicated than other auctions because of the network interactions among power flows on the grid. It is anticipated, for example, that the auction would be sequential because this would allow participants to see where injections and withdrawals to and from the system are valued by other users of the system (due to network effects) and to modify their bids accordingly.

VI. CONCLUSION

The Proposal is a significant step towards the creation of a competitive spot market for power and transmission in New York that can form the foundation for the development of competitive markets in longer-term products on a wider regional basis. The Proposal includes voluntary coordinated markets for unit commitment and dispatch, and can accommodate bilateral physical transactions as easily as any other trade. Locational pricing will serve as a basis for the efficient supply of electricity in New York and beyond. The combined features solve the principal problems of transmission access for a competitive market while recognizing the realities of the electric system. The arrangements for the ISO and voluntary PEs will allow all wholesale market participants the flexibility needed for their trading activity.

I, William W. Hogan, do swear and affirm that the attached document, entitled "Report on the Proposal to Restructure the New York Electricity Market" was prepared by me or under my direct supervision, that the statements made therein are true and accurate to the best of my knowledge and belief, and that in any proceeding involving this filing, my testimony would be based upon and consistent with the statements and opinions expressed therein.

Signed and sworn to before me on this
29 day of January 1997.

Notary Public

MARY JANE ROSE
Notary Public
Commission Expires
October 18, 2002