Proxy Buses and Congestion Pricing of
Inter-Balancing Authority Area Transactions

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I. OVERVIEW

The most fundamental of all seams issues is the need of adjacent balancing authority areas to coordinate their net interchange. One aspect of this coordination involves the evaluation of the impact of incremental net interchange on congestion on transmission constraints within the scheduling balancing authority areas.[2] If there is no transmission congestion and no impact on system losses, the value of interchange power can be assessed merely by comparing the incremental dispatch cost within the receiving balancing authority area to the offer price of the imported power. If there is transmission congestion, however, then the scheduling of interchange power may not entail simply backing down the highest cost generation within the receiving balancing authority area but may require dispatching down a combination of low and high cost internal generation or even dispatching some high cost internal generation up out of merit to reduce flows on potentially overloaded transmission elements. Hence the evaluation of the value of interchange power requires assessment of the extent to which the imported power would allow the receiving balancing authority area to decrement high cost versus low cost internal generation.

Because power flows over all parallel paths from source to sink, an evaluation of the congestion impacts of imported power requires an assessment by the importing balancing authority area of the source of the imported power (i.e., the location at which generation would be incremented or decremented to support a change in net interchange). While all system operators carry out such an evaluation, they do not all use the same methods. Non-RTO system operators, for example, in some cases use ad hoc subjective methods to evaluate these congestion impacts, and these methods can be a source of concerns regarding the potential for discrimination. RTO system operators, on the other hand, tend to use model-based methods for evaluating such congestion impacts, particularly since under market-based systems, it is necessary for settlement purposes to either price interchange power or to price the transmission service used to deliver the power to load (including transmission congestion costs), as well as simply scheduling it.

All of the existing LMP based pricing systems currently utilize proxy bus mechanisms for analyzing and pricing the congestion impacts of interchange schedules. A fundamental feature of LMP pricing systems is that when transmission constraints are binding, location matters, and this is true for the location of external as well as internal generation. The location and number of proxy buses used by LMP pricing systems to model imports and exports has been a subject of

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[2] There are also mechanisms to account for the impact of interchange transactions on transmission congestion within control areas that are not on the contract path, i.e., parallel flows in balancing authority areas not involved in scheduling a transaction. This paper focuses on the impacts on the scheduling balancing authority areas.

continuing discussion and evolving practice since the initial implementation of LMP pricing in PJM on April 1, 1998.

This paper describes the purpose and operation of proxy bus pricing systems, discusses the issues relating to the choice of proxy bus location and the number of proxy buses, and reviews the evolution of the proxy bus systems employed by NYISO, PJM, and ISO-NE and discusses the reasons behind the changes over time in proxy bus design. The paper focuses on five important features of proxy bus pricing and scheduling systems:

- The purpose of modeling changes in scheduled net interchange with an adjacent balancing authority area as sourcing or sinking at a proxy bus is to approximate the combined effect on congestion within the modeling balancing authority area (i.e., the change in flows on binding transmission constraints secured by the modeling balancing authority areas) of all changes in generation in the adjacent balancing authority area that would occur in response to a change in scheduled net interchange between the modeling balancing authority area and the adjacent area.

- The appropriate number of proxy buses depends, in part, on the number of separate tie line schedules that are managed by the system operators.

- Defining proxy bus locations in excess of the number of tie line schedules managed by system operators introduces the potential for significant market inefficiency. The cost of this inefficiency will typically be borne, at least in part, by power consumers in one or both of the affected balancing authority areas.[3]

- If there are multiple balancing authority areas along a common interface, defining individual proxy buses for each balancing authority area can lead to significant inefficiency, even if there is a distinct interchange schedule with each balancing authority area. As above, the cost of this inefficiency will typically be borne by power consumers in the importing or exporting balancing authority area.

- Proxy bus pricing systems are typically based upon network models that include all or portions of the transmission system in adjacent balancing authority areas.

Two important themes that emerge from this discussion are:

- There is no single proxy bus location that will be ideal from the standpoint of modeling the impact of changes in scheduled interchange on transmission congestion over all hours of the year and over all system conditions. It will be necessary to choose a proxy bus that provides the best approximation of actual system impacts under likely system conditions.

- It will be difficult to assess ex ante the best location for a proxy bus and the ideal location may change over time with changes in the generation mix in external

[3] Depending on the details of the RTO market design, these costs could be manifested in higher energy prices, in congestion rent shortfalls, or in real-time uplift costs.

> regions, changes in dispatch and transmission scheduling practices in the adjacent balancing authority area, and changes in market participant behavior. The location of a proxy bus may need to be modified over time based on operating experience to reflect these kinds of changes in the operational environment.

Proxy bus pricing systems are used both to price interchange between market and non-market regions and between market regions that utilize coordinated redispatch, such as PJM and MISO. In order to keep the scope of this paper manageable, it focuses on proxy bus pricing as applied between regions that do not utilize coordinated redispatch.

Section II explains the role of proxy buses in valuing imports and exports in LMP markets and discusses the issues that arise in determining the appropriate number and location of proxy buses. Section III describes the proxy buses utilized by PJM, the NYISO and ISO-New England, and discusses how they have evolved over time to address the issues discussed in Section II. Section IV briefly discusses the establishment of proxy buses for controllable lines. Section V contains examples illustrating the issues discussed in Section II.

II. PROXY BUS PRICING IN LMP MARKETS

A. General Principles

A proxy bus in eastern LMP based transmission pricing systems is a location at which generation in an adjacent balancing authority area is modeled for congestion pricing purposes (for the purpose of analyzing the impact of changes in net interchange on transmission congestion internal to the scheduling balancing authority area) as incremented to support imports from and decremented to allow exports to that adjacent balancing authority area. More specifically, the proxy bus is the location at which the dispatch and pricing models assume that generation in the adjacent balancing authority area is increased to support exports from that balancing authority area and decreased to accommodate imports into that balancing authority area. Importantly, the proxy bus location is typically not a delivery or metering point for net interchange power, does not necessarily correspond to the location of the Balancing Authority Operator with whom transaction checkout is conducted, and is not used to enforce contract path scheduling limits.

In LMP pricing systems the proxy bus is typically not simply an interface scheduling location modeled as radially connected to the ISO-coordinated transmission system (unless, of course, the adjacent system is connected via a single radial line).[4] Except in the case of controllable lines, it is also not the location at which interchange flows are metered. Instead, the transmission grid model employed by LMP based pricing systems extends beyond the internal ISO-coordinated transmission grid and represents, sometimes in a simplified or equivalenced manner, the transmission network in adjacent dispatch regions. An increase or decrease in generation at an external proxy bus will therefore generally be modeled as potentially impacting the flows on

[4] Consistent with its zonal pricing model, the California ISO has until now represented external locations as radially connected to the California grid and not taken account of the impact of external transactions on interzonal congestion.

multiple free-flowing tie lines (lines connecting the balancing authority area).[5] External proxy buses are locations on this external transmission grid that have been selected by the modeling balancing authority area for calculating the likely impact on the transmission system flows of the modeling balancing authority area of the combined effect of all changes in generation in the external region that would occur to support changes in the level of scheduled net interchange with the modeling balancing authority area.

The distinction between internal generation and load that are modeled at their actual location on the grid, and imports and exports which are modeled at a proxy bus arises because, under current dispatch procedures, a system operator (regardless of whether that system operator is an ISO/RTO or a vertically integrated balancing authority area) typically does not control the location at which generation in an adjacent balancing authority area is increased or decreased to support changes in net interchange.[6] That is, if the system operator in balancing authority area A accepts schedules for an additional 100 MW of imports from adjacent balancing authority area B, the system operator of balancing authority area A would not determine which specific generating units in balancing authority area B would be incremented to support the 100 MW change in net interchange. This would be determined either by the system operator dispatching balancing authority area B or the entity scheduling generation to support the interchange schedule. The pattern of power flows over free-flowing tie lines, and the impact on transmission constraints internal to balancing authority area A associated with a change in scheduled net interchange between balancing authority areas A and B may, however, depend on the specific location at which generation will be incremented in balancing authority area B. In analyzing the impact of this change in net interchange on its transmission constraints, and thus in both analyzing reliability impacts and valuing the interchange power, the system operator dispatching balancing authority area A must therefore make assumptions regarding the location at which the generation in balancing authority area B would be incremented to support exports to balancing authority area A.[7]

An external proxy bus is, in essence, the location at which the system operator assumes (for the purpose of modeling the congestion impacts on transmission lines within its balancing authority area) that generation in the adjacent balancing authority area will be dispatched up and down in conjunction with changes in scheduled net interchange with that balancing authority area.[8] This

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5 It is important to recognize that these models do not assume that *all* generation and load in the adjacent dispatch region is located at the proxy bus. Generation and load may be modeled as spread out over the transmission grid of the adjacent dispatch system for the purpose of modeling loop flows. The proxy bus simply models the location at which *marginal* changes in generation are assumed to occur in response to marginal changes in net interchange.

6 An exception is that the location of generation supporting dynamic schedules is known, and the output supporting the dynamic schedule is metered so dynamic interchange schedules need not be priced at a proxy bus.

7 Conversely, in order to analyze the impact of increased exports on transmission congestion within balancing authority area B, the system operator of exporting balancing authority area B must make assumptions regarding the locations at which the system operator for balancing authority area A would decrement generation in response to an increase in imports.

8 The IDC used in the eastern interconnection to analyze the impact of loopflows associated with inter-control area transactions on off-contract path transmission systems for security coordination purposes (TLRs) also

is the case both for system operators in LMP markets and non-RTO system operators who also must use some set of assumptions if they are to analyze the impact of changes in net interchange on their internal transmission constraints. In an LMP market these calculated congestion impacts are also used to price imported and exported power, and to determine congestion charges on transmission schedules.

It is important in understanding the use of proxy buses to analyze congestion impacts to recognize that system operators cannot, in general, base their analysis of congestion impacts for a particular hour or dispatch interval on the observed flows on interregional tie lines attributable to a particular source of interregional transactions or to particular changes in net interchange during that period. This is because the flows observed on free-flowing interregional tie lines generally depend not only on net interchange between the directly interconnected balancing authority areas (and the location of the generation within those balancing authority areas used to support the change in net interchange) but also on the pattern of generation to meet load within each of the connected balancing authority area (which create loopflows through the adjacent interconnected balancing authority area) and the pattern of generation throughout the rest of the AC interconnection (which creates additional loopflows on the free-flowing tie lines). Thus, for example, the pattern of flows observed on the AC ties between PJM and NYISO depends not only on the location of generation used to support any change in net interchange between NYISO and PJM during a particular hour, but also on the pattern of generation and load within PJM (which would give rise to loop flows through NYISO), the pattern of generation and load within NYISO (which gives rise to loopflows through PJM), and the generation and load patterns throughout the rest of the eastern interconnection (which also gives rise to loopflows on the ties lines between NYISO and PJM).

Because the observed pattern of tie line flows depends on both unobserved loop flows arising from the dispatch and interchange of other balancing authority areas in the eastern interconnection and on the generation used to support scheduled interchange with a particular balancing authority area, it is not possible to directly determine from these total flows the location of the generation in the exporting balancing authority area that was used to support a change in net interchange or to identify the flows attributable specifically to the interchange schedule during a particular period. One can, however, analyze the relationship over time between changes in flows and changes in net interchange and draw conclusions regarding the typical location in an adjacent balancing authority area of the generation used to support exports or decremented to allow imports. Or, as discussed below, one can apply rules to the observed flows to calculate proxy bus prices that vary, albeit imperfectly, with changes in external generation sources and powerflows.

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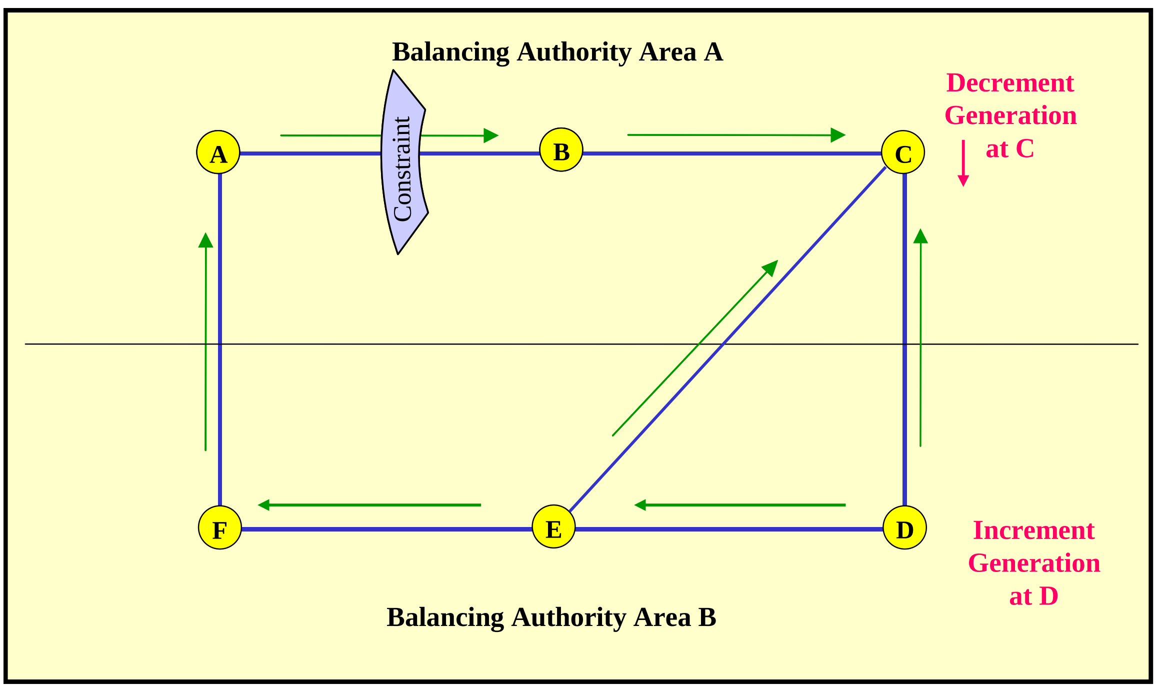
embodies a set of assumptions regarding the locations within a control area at which generation would be incremented or decremented to support a particular transaction. The scope of this paper is limited to the proxy bus mechanisms used by eastern RTOs; however, some of the limitations of the TLR process are related to the issues discussed in this paper.

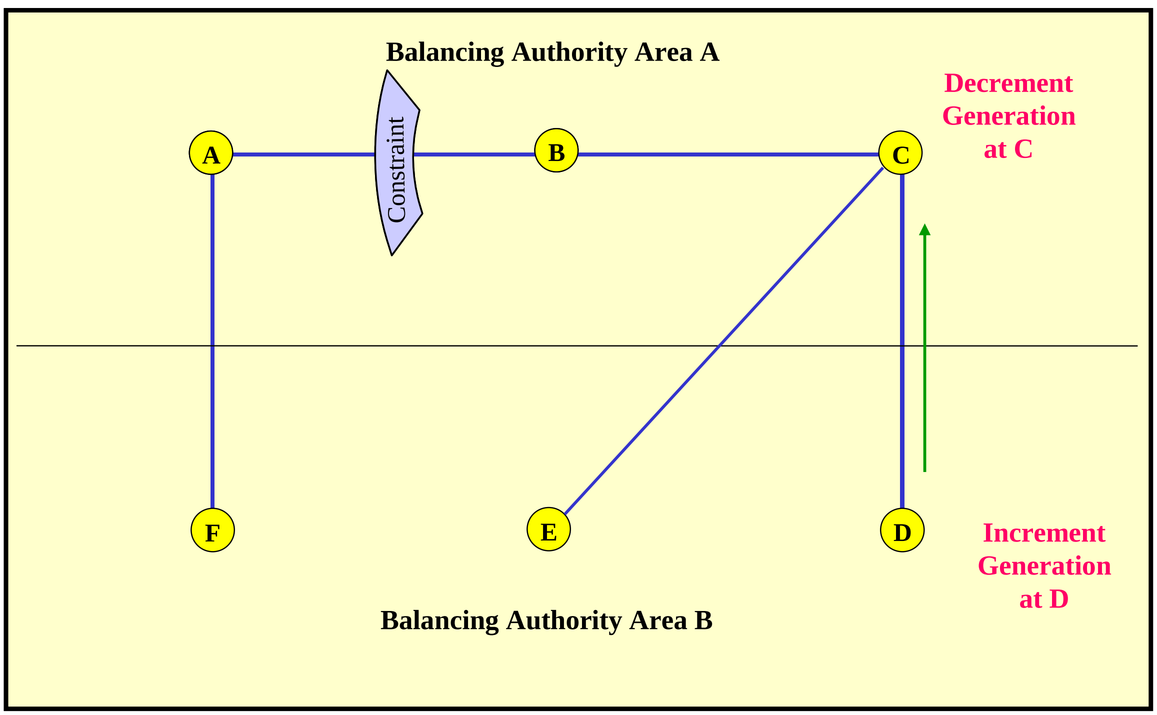
A proxy bus pricing system for scheduled net interchange also differs, except in the case of controllable lines, from modeling imports and exports as flowing over radially connected individual tie lines into the receiving balancing authority area. Under a proxy bus system, changes in scheduled interchange with an adjacent balancing authority area will be modeled for the purpose of analyzing impacts on internal transmission constraints as causing a change in the flows over all of the free flowing tie lines connecting the two balancing authority areas. Thus, as illustrated in Figure 1, if generation were incremented at D and decremented at C, the change in net interchange would cause power to flow over all of the parallel paths between D and C, including the transmission constraint between A and B. The value of an increase in net interchange with balancing authority area B supported by an increase in generation at D would be less than the value of an increase in net interchange supported by an increase in generation at C because more lower cost power at A, rather than high cost power at C, would have to be dispatched down to accommodate the impact of the imports on the constrained line A-B.

Figure 1
Proxy Bus Analysis of Congestion Impacts



Under a radial model of balancing authority area interconnections, on the other hand, the change in interchange would be scheduled to flow over individual tie line and the congestion impacts would be modeled based on this assumption. The external loops between F and E and E and D that were included in Figure 1 would be removed and locations D, E and F would be modeled as radially connected to North ISO, as shown in Figure 2. With such a model, if an increase in net interchange were scheduled over line D-C and high-cost generation at C decremented, there would be no impact on the flows over the line A-B, so the value of net interchange scheduled over the D-C line would be exactly the same as the value of power at C. The problem with this modeling approach from the standpoint of modeling congestion impacts for both reliability and pricing purposes is that while D is radially connected to C in the model portrayed in Figure 2, D is not radially connected to C in the actual power grid portrayed in Figure 1. As a result, in the real world, some of the net interchange scheduled on line D-C would in reality flow around over A-B to C, so balancing authority area A would find it necessary to back down some lower cost generation at A to accommodate the imports without overloading line A-B.

Figure 2
Radial Model Analysis of Congestion Impacts



Because external proxy buses are simply generation locations within a transmission network model, an LMP-based market system can calculate an LMP price for each external proxy bus. The LMP price at a proxy bus modeled by a given ISO will reflect the impact of net generation at the proxy bus location on transmission constraints within the region dispatched by that.[9]

[9] For regions that include the cost of marginal losses in location prices (currently NYISO, ISO-NE, MISO and PJM) the determination of the LMP price at a proxy price differs from the calculation of internal LMP prices in that the LMP price at the proxy bus includes the marginal cost of losses incurred on flows from the proxy bus to

Importantly, except in regions with coordinated dispatch (such as PJM and MISO) , the LMP price at the proxy bus will not reflect the impact of generation at the proxy bus location on transmission constraints within the dispatch region with which interchange is being coordinated, those constraint imports would be managed by the other system operator.[10]

PJM, NYISO, ISO-NE and MISO all use proxy bus methods to model and price net interchange with adjacent balancing authority areas.

B. Proxy Bus Pricing Issues

Important market design issues involving proxy buses in LMP based transmission pricing systems are the location selected for the proxy bus and the determination of the appropriate number of proxy buses for representing transactions with adjacent balancing authority areas or balancing authority areas.

The discussion below explains why in practice, except in the case of radially connected dispatch regions, no single proxy bus location will provide a perfect representation, under all conditions, of the changes in line flows associated with a change in scheduled net interchange with that balancing authority area. The location of the proxy bus in any single proxy bus pricing system is therefore necessarily a compromise that will not be ideal over all system conditions. There are, however, a number of elements of flexibility within a single proxy bus pricing system can be utilized to better approximate the actual system impacts of changes in scheduled net interchange.

This section then turns to a discussion of the problems that result from the use of multiple proxy buses to price a single interchange schedule over free-flowing ties with an adjacent balancing authority area. The choice of a single versus multiple proxy bus location for scheduling inter-balancing authority area transactions is an often misunderstood element of electricity market design. While it might seem that the introduction of multiple proxy buses that allows market participants to choose the proxy bus used to schedule their transactions might provide a better approximation of system impacts than a single proxy bus model, this is not the case; in fact, just the reverse will generally be the case. It is seen that such a multiple proxy bus design will likely provide market participants with financial incentives to schedule transactions such that the proxy bus used to schedule their transactions does not reflect the actual location of the generation that would be dispatched to support the transaction. Moreover, this effect is systematic, causing a system operator employing a multiple proxy bus system to price scheduled net interchange in a manner that incurs costs that must be recovered from market participants in uplift charges. Despite the approximations inherent in a single proxy bus system, no more than one proxy bus should be established to price a single interchange schedule with an adjacent balancing authority area.

the border of the balancing authority area using the proxy bus model, but includes only the cost of losses that would be incurred on transmission facilities within that control area.

[10] For the sake of simplicity, and because it is not relevant to current WECC practices, this paper does not discuss proxy bus pricing of interchange between regions that have implemented such market-to-market redispatch.

Finally, we turn to a related case, in which there is only one proxy bus for each adjacent balancing authority area or balancing authority area, but there are multiple, interconnected adjacent balancing authority areas or balancing authority areas scheduling interchange that impact a common interface. It is seen that this situation can give rise to many of the same problems as a multiple proxy bus system, and that these problems will likely become more acute as the level of pancaked rates falls or as the level of internal control area congestion rises. Thus, it can be necessary and appropriate to establish even fewer proxy buses than the number of interchange schedules established for a common interface.

Single Proxy Bus System

Under a single proxy bus system, all interchange scheduled with an adjacent balancing authority area is assumed to result in changes in net generation at the location of the proxy bus. Thus, increased imports from that balancing authority area are modeled as resulting in an increase in generation at the proxy bus location and decreased imports (or increased exports) are modeled as resulting in a decrease in generation at the proxy bus location. If there were no binding transmission constraints within the importing balancing authority area, the location at which generation would be increased in the adjacent dispatch area would be of no consequence to the area, as changes in the pattern of power flows would not matter to the importing balancing authority area from either a cost or reliability standpoint. This would also be the case if there were binding transmission constraints within the modeling balancing authority area but all generation within the adjacent balancing authority area had the same impact on these constraints.

The selection of the proxy bus location is important because a single proxy bus used to manage a single interchange schedule with an adjacent balancing authority area can fail to produce the optimal level of net interchange with respect to congestion impacts if three conditions hold:

- The proxy bus, and thus the assumed location of marginal generation in the adjacent balancing authority area, does not correspond to the actual location of marginal generation in the adjacent balancing authority area;
- The modeling balancing authority area has binding transmission constraints; and
- The change in flows on these binding constraints depends on the location at which generation is increased or decreased in the adjacent balancing authority area to support changes in net interchange.

If the modeling balancing authority area has binding transmission constraints and the change in flows on these binding constraints depends on the location at which generation is increased or decreased in the adjacent balancing authority area to support changes in net interchange, then the location of the proxy bus selected by the modeling balancing authority area matters. If the difference between the proxy bus location and the actual location at which generation is incremented in the other balancing authority area to support a change in net interchange is such that the actual change in generation has a less favorable impact on binding transmission constraints than would generation located at the proxy bus, then the proxy bus representation would cause the system operator to overvalue imports from the adjacent balancing authority area and hence to pay too much for imported power (or collect too little in congestion charges on the imports), likely scheduling more imports than is actually economic, or perhaps even feasible from a reliability perspective. This situation would result in real-time revenue inadequacy for the importing (modeling) ISO as day-ahead or hour-ahead schedules would have to be backed down or supported by out-of-merit real-time redispatch to eliminate the infeasibilities resulting from the import schedules, while the import price would have been set too high for the congestion charges on these imports to pay for this redispatch. For example, in Figure 1 above, if the proxy bus were defined at bus D, but generation were actually incremented at location F, an increase in imports from control area B would have a greater than modeled effect on the constraint A-B, allowing less generation at C to be dispatched down that would have assumed in determining the interchange price based on the proxy bus at D.

Alternatively, if the generation actually incremented to support changes in interchange has a more favorable effect on the binding transmission constraints than generation located at the proxy bus location, then the proxy bus price would be understated (i.e., not reflect the actual value of imports) and would tend to cause fewer imports to be scheduled than would be economic. This would correspond in Figure 1 to a situation in which the proxy bus was located at bus F, but generation were actually incremented at bus D, so that less power than modeled would flow over the constraint A-B, allowing more high cost generation at C to be backed down than was assumed in determining the interchange schedule or setting the interchange price. Under most ISO settlement systems this second kind of error would not be manifested in revenue inadequacy in ISO congestion rent settlements but would mean that load has not have been met at least cost.

In the single balancing authority area, single interchange schedule context, the choice of proxy bus location should be guided by several considerations. First, the location of load and fixed generation is irrelevant for the marginal analysis by the importing region of changes in line loadings in response to changes in scheduled interchange. The location of generation that is relevant to the pricing and scheduling of incremental net interchange and the selection of a proxy bus is the location at which marginal generation would be dispatched up or down in response to changes in the level of net interchange.[11] Thus, it is desirable that the location of the proxy bus used to model the impact of changes in scheduled interchange with an adjacent balancing authority area represent as well as possible the impact on tie line flows of dispatching marginal generation up or down in the adjacent dispatch area in response to changes in the level of net interchange.

Since each system operator would dispatch its resources to meet load, including net exports, at least cost, the generation that would be dispatched up to support exports would be the lowest cost undispatched generation, given load levels and transmission constraints within the exporting balancing authority area. The location of the lowest cost undispatched marginal generation in an adjacent balancing authority area is not fixed, but instead will depend on the level of load within the exporting balancing authority area and the location of transmission constraints within the exporting balancing authority area. As a result, the location of marginal generation within an

[11] The location of all external generation is potentially relevant to the estimation of total loopflows, which can have a material impact on which constraints are binding.

adjacent balancing authority area will move around with changes in load and transmission constraints so that no fixed proxy bus can ever provide a representation of marginal generation sources that is ideal over all hours of the year. Instead, the proxy bus location must be selected to provide the best approximation of the location of marginal generation within the adjacent balancing authority area at times when interchange is scheduled and transmission constraints are binding within the modeling balancing authority area.

In achieving this goal of defining a single proxy bus location that provides the best approximation of the location of marginal generation within an adjacent dispatch balancing authority area, a single proxy bus model has a number of elements of flexibility that can be utilized. First, the single proxy bus need not be defined as a single node. While the NYISO has historically defined its proxy bus locations as individual nodes, the single proxy bus used to model interchange with an adjacent balancing authority area could be defined as the weighted average of a number of nodes, rather than a single location. PJM applies such a practice as will be discussed in Section III.

Second, the location of the single proxy bus location is not necessarily fixed. One way to address the issues created by a shifting marginal source of generation would be to employ a proxy bus definition that also shifts around with changes in conditions. Such an approach can be difficult to implement in practice due to a lack of the necessary data regarding external conditions and the lack of predictability associated with a shifting proxy bus definition could potentially adversely impact the scheduling of interchange transactions by market participants. PJM has shown that such an approach can be implemented, having used such a shifting proxy bus to price interchange with the NYISO since 2001, as discussed in Section III below.

Multiple Proxy Bus Systems

Given the approximations inherent in a single proxy bus pricing system for interchange, an important market design issue involving proxy buses in LMP based transmission pricing systems has been the determination of the appropriate number of proxy buses for representing transactions with adjacent balancing authority areas. For example, if a system operator were to define two or more proxy bus locations for market participants to utilize in scheduling transactions over free flowing ties with a single adjacent balancing authority area with whom a single net interchange schedule is established, market participants would be able to choose which proxy bus to utilize for scheduling individual transactions between the balancing authority areas.

This ability of market participants to vary the proxy bus used for dispatch and pricing might at first appear to be useful in addressing the limitations of a single proxy bus system described above but this is not the case if there is a single interchange schedule with the adjacent dispatch region. In such a situation the system operators would dispatch the system without regard to the separate proxy bus schedules, since there would be a single interchange schedule. As a result, the use of multiple proxy buses to schedule a single level of tie line flows would simply provide market participants with a financial incentive to select the proxy bus used for transaction scheduling based on the prices at these proxy buses, without any effect on the actual power flows on the transmission system.

The establishment of multiple proxy buses for a single interchange schedule therefore does nothing to ensure consistency between the designated proxy bus and the actual location at which generation is dispatched up or down to support changes in net interchange. The central feature of a multiple proxy bus system for scheduling a single level of tie line flows that needs to be considered in assessing the operation of such a system is that the dispatch of the exporting balancing authority area is in general completely unaffected by which proxy bus has been designated by market participants as the source of export transactions. The system operator of the exporting region would simply dispatch its system at least cost to support the higher level of net interchange (i.e., to maintain the scheduled level of tie line flows).

The designation of a proxy bus for scheduling purposes by a market participant under such a multiple proxy bus system for scheduling a single level of tie line flows can therefore affect the pricing of interchange power by the modeling balancing authority area but the designation would have no impact on the tie line flows managed by the system operators nor on the location at which generation would be incremented or decremented to support the change in net interchange. If the transmission system in the modeling dispatch area were constrained, the value of the interchange power would depend on the location at which generation were incremented and decremented by the other system operator. Under a multiple proxy bus system for scheduling a single level of tie line flows, market participants would compare the prices associated with each proxy bus and select the proxy bus with the most favorable price.

For example, if market participants had the option of designating either bus D or F in Figure 1 as the source or sink for their transactions and bus D had the higher price, then market participants would designate bus D as the source when exporting power to Balancing Authority Area A and would designate bus F as the sink when buying power from Balancing Authority Area A. If locations D and F were merely used for transaction scheduling purposes, the offsetting transactions would not matter to the control area operators and some transmission owner would be collecting transmission charges on the offsetting transactions. If locations D and F are used to price power or congestion charges within a LMP market, however, such offsetting transactions that yield no net interchange flows could nevertheless require net payments by the system operator (the difference between the price at F paid for imports and the price at D charged for exports). The problem with such dual proxy bus single interchange schedule systems from the standpoint of the system operator and the consumers who will bear the resulting costs is that system operator will pay a premium for a proxy bus designation that has nothing to do with how the power will actually flow and thus has no value to consumers. Such a dual proxy bus system will be beneficial to entities that are able to schedule transactions to exploit the inefficiency of the system without having to bear the associated uplift costs but is not in the interest of consumers.

These problems arising from the use of multiple proxy buses to price a single interchange schedule are not hypothetical but arose for PJM on the NYISO interface during 2000 and early 2001. PJM initially used two distinct proxy buses, NYPP East and NYPP West, to price interchange with New York. The schedules for these proxy buses were completely unrelated to the schedules for the PAR controlled lines between PJM and New York, and aside from the PAR schedules, there was a single net interchange schedule between PJM and New York. While the schedules established for the two New York proxy buses had no operational significance, as predicted above, market participants took advantage of their scheduling flexibility to schedule exports to New York from PJM at the lower-priced proxy bus and schedule imports to PJM from New York at the higher-priced eastern proxy bus, operating a money machine that pumped money out of the PJM market, contributing to revenue inadequacy in real-time congestion rent settlements, until the pricing rules were changed as discussed in Section III.B below.

Multiple Balancing Authority Areas

The problem of money machines that create congestion rent shortfalls and raise uplift costs under multiple proxy bus systems discussed above arises because the multiple proxy buses allow market participants to define contract paths used for pricing do not reflect the actual power flows. The potential for inefficient scheduling incentives and revenue inadequacy under proxy bus systems is not limited to situations in which multiple proxy buses are defined for a single balancing authority area with a single interchange schedule, but can also arise in situations there is a single proxy bus in each balancing authority area but there are multiple adjacent balancing authority areas along a single interface.

If there are several balancing authority areas along a common interface with separate proxy buses and interchange schedules for each balancing authority area, market participants can schedule transmission along a contract path external to the ultimate delivery point for the power so that power sourced in a balancing authority area with a low proxy bus price would be delivered at a proxy bus with a higher proxy bus price. Suppose, for example, that Balancing Authority Area A in Figure 1 was a single balancing authority area, but that buses D, E and F were each separate balancing authority areas establishing separate interchange schedules with Balancing Authority Area A. If the transmission constraint on A-B were binding, the proxy bus price at D would be lower than the proxy bus price at F. Suppose, however, that the difference in proxy bus prices between D and F were larger than the transmission charges required to schedule transmission from D to E to F. Then market participants buying power at D would not schedule the power to flow from proxy bus D into Balancing Authority Area A and sell the power at the Proxy bus D price, but would instead buy transmission service from D to E to F and then sell the power into Balancing Authority Area A at the Proxy Bus F price.

Similarly, if a load in control area F wanted to buy power from Balancing Authority Area A, rather than paying the high price at Proxy Bus F reflecting the need to support those exports with high cost generation at C because of the transmission constraint on the line A-B, the load could buy power at bus D, at the lower price reflecting the more favorable impact on the A-B constraint of power delivered to load at D, and then schedule transmission along the contract path from D to E to F. The load would thereby pay the load bus D price for power actually sinking at bus F and having a less favorable impact on the A-B transmission constraint than power sinking at bus D.

The net effect of two such transactions would be that Balancing Authority Area A would be buying power at the high price at F and selling power at the low price at D, but rather than getting the favorable powerflows over the A-B constraint that would be associated with incrementing generation at F and decrementing generation at D, there would be an increase in generation at D and a decrease in generation at F, which would increase flows over line A-B, requiring the balancing authority area to back down low-cost generation at A and dispatch up higher-cost generation at C.

This potential for inefficient scheduling incentives with single proxy buses but multiple balancing authority areas is also not hypothetical as it basically describes the situation that arose for PJM in scheduling transactions with AEP and VACAR during 2002, as discussed below in Section III.B below.

III. EVOLUTION OF EASTERN PROXY BUS PRICING SYSTEMS

A. NYISO Proxy Buses

The NYISO initially had four proxy buses, one each for modeling interchange with ISO-NE, Ontario, PJM and Hydro Quebec.[12] Since NYISO start-up, four additional proxy buses have been added for the purpose of modeling the impact of power scheduled to flow over controllable lines (DC lines or PAR controlled lines) or in one case in order to separately model wheel-through transactions that are subject to special coordination rules between PJM and NYISO. These additional proxy buses are the proxy bus for the Cross Sound Cable from New England (June 7, 2005),[13] the 1385 line with New England (June 27, 2007), the Neptune line from PJM (July 1, 2007), and the Hydro Quebec wheel through proxy bus (July 1, 2007).[14]

New England Interface

The NYISO currently has three proxy buses for the purpose of modeling interchange with ISO-New England. Two proxy buses are used to model schedules over controllable lines between ISO-New England and NYISO (the Cross Sound Cable and the 1385 line). The third proxy bus, Sandy Pond, is used to model all transactions with ISO-NE that are not scheduled to flow over one of the controllable lines. Absent changes in schedules on the controllable lines, the NYISO models an increase in imports from ISO-NE as being supplied by increased generation at Sandy Pond, while increased exports from NYISO to ISO-NE are modeled as backing down generation at Sandy Pond.[15]

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12 See NYISO Technical Bulletin 37, May 19, 2000.

13 The Cross Sound Cable was initially energized following the black out in August 2003. The 2005 date is the point in time at which a separate proxy bus was implemented which allowed entities other than LIPA to schedule transactions on the line.

14 A proxy bus was scheduled to be activated for scheduling interchange on the Cedars-Dennison controllable line between Hydro Quebec and the NYISO on August 1, 2007; however, activation has been delayed until various regulatory issues relating to DOE regulations are resolved. Rana Mukerji, “Update on Northeast Seams Issues,” NYISO Business Issues Committee Meeting, December 5, 2007, p. 8.

15 See NYISO Technical Bulletin 37. Sandy Pond is the location of the ISO-NE end of a DC interconnection between Hydro Quebec and NEPOOL.

In addition to these flows over the free-flowing ties, transactions may also be scheduled between ISO-NE and Long Island on the Cross Sound Cable which is a DC line.[16] Power scheduled to flow over the Cross Sound Cable is modeled distinct from other net interchange with ISO-New England and as radially connected to Long Island (except for the contingency analysis of the Cross Sound Cable) because the amount of power flowing over this cable is determined by the cable operator, not by changes in generation in ISO-New England or in New York. The congestion impacts on New York are determined by the Cross Sound Cable schedule, rather than the location of the generation raised or lowered by ISO-NE to support the schedule.[17] Conversely, the congestion impacts on New England do not depend on the location at which the NYISO raises or lowers generation in response to changes in Cross Sound Cable schedules. Because the Cross Sound Cable is a merchant line with all capacity contracted for on a long-term basis by LIPA there are a number of special rules regarding the scheduling and pricing of power on the Cross Sound Cable that are not relevant to this paper.[18]

Since June 27, 2007 transactions between ISO-NE and NYISO may also be scheduled to flow on the 1385 line which is a phase angle regulator (PAR) controlled line between ISO-NE and Long Island.[19] Power scheduled to flow over the 1385 line is modeled distinctly from other net interchange between New York and ISO-NE and as radial to Long Island because the phase angle regulators can be used to ensure that the physical pre-contingency flows on the line correspond to the schedule.[20] Once again, the congestion impact of changes in interchange between NYISO and ISO-NE will differ depending on whether the power is scheduled to flow over the 1385 line or the remainder of the AC interface.[21]

All power scheduled to flow between ISO-New England and the NYISO is modeled as flowing over either one of the controllable lines or the lines making up the NYISO-ISO-New England interface. Because the Hydro Quebec control area is connected to ISO-NE and NYISO with DC lines, there are no loopflows through Hydro Quebec associated with the schedules between NYISO and ISO-New England, all scheduled net interchange flows over the lines on the NYISO ISO-New England interface.

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16 See NYISO Technical Bulletin 141, revised June 17, 2007, “Scheduling Transactions at the Proxy Generator Bus Associated with the Cross-Sound Scheduled Line.”

17 This is the case as long as the outage of the Cross Sound Cable is not a binding contingency. If the Cross Sound Cable were to trip out of service, the power scheduled to flow over the cable would instead flow over the free-flowing ties between ISO-NE and New York. See “Controllable Lines” Concept of Operation, New York Independent System Operator, January 8, 2003. The transfer capability of the Cross Sound Cable is small relative to other transmission contingencies on the NYISO-ISO New England interface so this outage contingency is not a practical consideration.

18 See NYISO Technical Bulletin 141 and the NYISO Filing letter in docket ER05-727-000 March 25, 2005

19 See NYISO Technical Bulletin 161, June 13, 2007, “Scheduling Transactions at the Proxy Generator Bus Associated with the Northport-Norwalk Scheduled Line.”

20 Changes in PAR settings can be necessary to hold line flows to the scheduled level and PARs can exhaust their ability to hold pre-contingency flows to the schedule.

21 As in the case of the Cross Sound Cable, this is true as long as the outage of the 1385 line is not the binding contingency. Since the scheduling limit on the 1385 line was initially set at 100MW (see NYISO Filing letter in ER07-806-000 April 27, 2007), the outage of the 1385 line would be far smaller than other contingencies on the NYISO-ISO-NE interface.

It is important to recognize that the location at which the NYISO models the New England proxy bus for the purpose of analyzing congestion impacts is not necessarily the same as the point of delivery or interconnection. While the proxy bus location and the point of delivery are the same for the controllable lines (the Cross Sound Cable and the 1385 line),[22] they are quite different in the case of the free-flowing tie lines between New York and New England. While the NYISO models internal congestion impacts with a proxy bus located at Sand Pond, internal to ISO-New England,[23] the actual point of delivery for power flowing over the free-flowing ties is the point at which the transmission lines cross the New York-New England border.[24]

PJM Interface

The NYISO currently has two proxy buses for the purpose of modeling interchange with PJM. One proxy bus is used to model schedules over the Neptune line between PJM and Long Island. The other PJM proxy bus is Keystone and it is used to model all transactions with PJM that are not scheduled to flow over the Neptune line.[25] If the schedules on Neptune do not change, the NYISO will analyze the congestion impacts of a change in net interchange between PJM and NYISO through a change in generation at Keystone.[26]

Thus, when an additional MWh of imports from PJM is scheduled in the NYISO day-ahead market, the NYISO's security-constrained unit commitment software (SCUC) models that import as if it were supported by a 1 MWh increase in net generation at Keystone, and the day-ahead LBMP price for that import is the price at Keystone. Underlying this modeling decision was the NYISO's expectation in 1999 that PJM's least cost dispatch would usually entail raising generation on a unit located somewhere in Western Pennsylvania, not in New Jersey. The selection of the NYISO PJM proxy bus was therefore intended to roughly reflect the region of PJM in which generation would usually be raised to support an export schedule to New York or decreased in response to increased imports from New York.

Until June 6, 2007, the NYISO day-ahead, hour-ahead and real-time dispatch software models treated phase angle regulator (PAR) schedules on the tie lines between NYISO and PJM as fixed; that is, they assumed that the PARs would be moved to hold flows to the schedule and thus that the schedule on the PAR controlled line was independent of the overall level of net interchange.

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22 "Coordination Agreement between ISO New England Inc. and New York Independent System Operator," January 1, 2006, p. 3 and Schedule A, pp. 24-25. http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/NYISO_ISONE_Crdntn_Agrmnt_1_1_06.pdf

23 NYISO Technical Bulletin 37.

24 "Coordination Agreement between ISO New England Inc. and New York Independent System Operator," January 1, 2006, p. 3 and Schedule A, pp. 24-25. http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/NYISO_ISONE_Crdntn_Agrmnt_1_1_06.pdf

25 Keystone is the location of a large coal-fired generator in Western Pennsylvania.

26 There are also a number of PAR controlled lines between PJM and NYISO for which separate proxy buses have not been established because the impact of the PAR controlled flows is accounted for in other ways. First, the ABC lines into New York City and the JK lines into New Jersey are PAR controlled and used to implement a wheeling agreement between Con Ed and PSEG. Second, the Ramapo PAR is used to control flows between NYISO and PJM.

Since most of the tie lines between NYISO and PJM in eastern PJM are PAR controlled, the assumption of fixed schedules on the PAR controlled lines meant that most imports from PJM were modeled as flowing into the NYISO on western transmission lines, lowering the value of these imports and also meant that the pattern of inter-regional flows did not vary much in NYISO models with changes in the location of the incremented or decremented generation in PJM, because most of the flows were determined by the assumed or actual PAR schedules.

A change in modeling assumption was introduced during 2007 which specified the fraction of NYISO-PJM interchange that would be modeled as flowing over the JK, ABC, and 5018 PAR controlled lines.[27] This change in modeling tended to raise the value of power imported from PJM when transmission constraints are binding in eastern New York. The scheduling of power over the ABC and JK lines is also governed by the PSEG-Con Edison wheeling agreement and the recently devised procedures to better implement that agreement.[28]

Back in 2000 and 2001 some market participants suggested that the NYISO should establish a separate Eastern PJM proxy bus and model import supply at the Eastern PJM proxy as having an impact on New York transmission constraints of a generator being raised in Eastern PJM. Had the NYISO established dual PJM proxy buses, market participants would undoubtedly have scheduled imports into New York as sinking at the Eastern PJM proxy bus (so they would be paid a high price for the imports) and exports to PJM as sourced from the Western PJM proxy bus (So they would be charged a low price for the exports.) This ability to choose the proxy bus price would have raised the proxy price paid by the NYISO for imports that were scheduled for delivery at the NYISO's Eastern PJM proxy bus. This higher payment would not have changed the location of the generation raised by PJM to support exports, however, NYISO market participants would have paid the higher Eastern PJM proxy price for generation flows that, if the NYISO's expectations regarding the PJM dispatch are correct, would actually have come from Western Pennsylvania and would have required backing down cheap Western New York generation, rather than displacing expensive Eastern New York generation. The imports scheduled from this proxy bus would have raised, not lowered, the cost of meeting load in New York.

Since July 1, 2007 transactions between PJM and NYISO may be scheduled on the Neptune line which sources in New Jersey and sinks on Long Island.[29] Because the Neptune line is a DC cable, the flows on this line can be controlled separately from the overall level of interchange on the PJM interface and the flows on the line will vary with schedules. The flows on the Neptune line are therefore modeled as radially connected to Long Island, except for the purpose of modeling the outage of Neptune itself.

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[27] NYISO Technical Bulletin 152, revised May 8, 2007, "PJM Proxy Bus Pricing and Scheduling." Michael Martin (NYISO), "PJM Proxy Bus Pricing Enhancements – Post-Implementation Review," MIWG October 17, 2007, located at http://www.nyiso.com/public/committees/documents.jsp?com=bic_miwg&directory=2007-10-17&cols=5&rows=5&start=1&maxDisplay=999.

[28] See PJM Market Monitoring Unit, "2005 State of the Market Report," pp. 199-203; "2006 State of the Market Report," pp. 189-190, located at http://www.pjm.com/markets/market-monitor/som-reports.html. "Joint Compliance Filing of NYISO, PJM and PSEG," Docket EL-02-23-00, February 18, 2005.

[29] See NYISO Technical Bulletin 162, July 10, 2007, "Scheduling Transactions at the Proxy Generator Bus Associated with the Neptune Scheduled Line."

The NYISO models all scheduled net interchange between PJM and the NYISO as flowing over either the Neptune line or one of the AC lines connecting PJM and the NYISO. Thus, for the purpose of modeling congestion impacts on the NYISO transmission system, the NYISO does not take account of the loopflows around Lake Erie and through Ontario associated with PJM to NYISO schedules. This assumption is inaccurate but it has so far provided a workable approximation for the NYISO, probably because this assumption is not material for calculating flows on constraints in eastern New York and transmission constraints in western New York rarely bind. These assumptions would be material for calculating the flows over lines between New York and PJM, and between New York and Ontario. Those interfaces are scheduled based on scheduling limits in part because allowance must be made for substantial loop flows unrelated to NYISO transactions.

As in the case of ISO New England, the location at which the NYISO models the PJM proxy bus for the purpose of analyzing congestion impact is distinct from the point of delivery or interconnection in the case of the free-flowing ties. While the NYISO model's internal congestion impacts with a PJM proxy bus located at the Keystone generation plant, the actual points of delivery for power flowing over the free-flowing ties are different.[30] While two of the common meter points are at Homer City, the proxy bus is not located radially at the end of the Homer City transmission lines but at the Keystone generator.

Hydro Quebec Interface

The NYISO currently uses two proxy buses to represent transactions scheduled with Hydro Quebec. The first proxy bus is Chateauguay, which is the location of the main interconnection with Hydro Quebec. The second proxy bus is an additional proxy at Chateauguay that is used to model wheel through transactions with Hydro Quebec.[31] Both proxy buses are modeled as located at the same place electrically, having exactly the same shift factors on all constraints. The second proxy bus is used only for the scheduling of wheeling transactions in excess of the 1,200 MW NYISO first contingency. The Hydro Quebec-NYISO interconnection differs from the Ontario, PJM and NEPOOL interconnections in that there is no AC interconnection between the transmission system serving Hydro Quebec and the NYISO.

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30 "Joint Operating Agreement Among and Between New York Independent System Operator Inc. and PJM Interconnection, LLC," May 2007, p. 4 and Schedule A, p. 32. http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/nyiso_pjm_joa_final.pdf

31 See NYISO Technical Bulletins 37 and 158 revised July 23, 2007; NYISO filing in docket ER07-669-000 March 28, 2007. Net imports to the NYISO from Hydro Quebec are normally limited to 1200MW which is the largest contingency for the NYISO control area. If imports from Hydro Quebec at Chateauguay exceed 1200MW, the loss of the connection with Hydro Quebec would become the largest contingency, changing the reserve requirements for the NYISO. Procedures have been worked out between Hydro Quebec, NYISO and PJM, however, that permit the NYISO to schedule up to 1200MW of net imports from Hydro Quebec plus additional wheel through transactions to PJM, whereby in the event of the loss of the Hydro Quebec connection, the wheelouts to PJM will also be cut, so that the NYISO's single largest contingency remains 1200 MW. See NYISO Technical Bulletin 158. The additional proxy bus was added at Chateauguay to enable the NYISO to better implement this treatment of wheel through transactions.

Ontario

The final NYISO proxy bus is Bruce, the NYISO proxy bus for transactions with the Ontario IESO.[32] Symmetric with the NYISO's modeling of PJM, the NYISO models effectively assume that Ontario is radial to the NYISO with no loop through Michigan.

The NYISO is potentially exposed to inter-balancing authority area contract path scheduling impacts for power originating in MAIN which could schedule a contract path to New York either through Ontario or through PJM. Since generation at the PJM proxy bus has a more favorable impact on Central East than generation at Bruce in Ontario, it is likely that most entities scheduling imports into NYISO from MAIN originally chose a contract path coming in through PJM, rather than through Ontario, although the power actually flowed through both Ontario and PJM. This type of contract path scheduling has to date not been an issue for the NYISO. This may in part have been because both the PJM and Ontario proxy buses are electrically well to the west of Central East, however the differences between the shift factors of the PJM and Ontario proxy buses on Central East are not insignificant.

Historically, it may have been the case that most scheduling of MAIN generation into the NYISO was along a contract path through PJM, but that the impact of such MAIN imports was limited by the cost of scheduling contract path transmission from MAIN into NY under pancaked tariffs in the Midwest, so that few such imports were scheduled. It may therefore be the case that with the reduction in pancaked tariffs in the Midwest following the implementation of the MISO energy markets, the NYISO may over time see an increase in generation schedules that have contract paths through PJM, but that if accepted by NYISO, will cause incremental generation to be dispatched in MAIN or even MAPP.

Such a change in generation patterns could make it desirable for the NYISO to move its PJM proxy bus further west, potentially even into ECAR, to reflect the actual location of incremental generation and bring modeled flows on Central East more in accord with actual flows. On the other hand, the expected 2008 operation of PARs controlling Ontario to Michigan power flows, may not only obviate the problem of contract path scheduling into the NYISO but may also make the impact of other loopflows on Central East more predictable.

As in the case of ISO-NE and PJM, the location of the NYISO's proxy bus is distinct from the points of interconnection at which power is delivered from one transmission system to the other. The points of interconnection are on the international border between Ontario and New York.[33]

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[32] NYISO Technical Bulletin 37. Bruce is the site of substantial nuclear generation.

[33] See "Interconnection Agreement Between Independent Electricity Market Operator and the New York Independent System Operator, Inc." May 1, 2002, pp. 4, 5 and Schedule A, p. 29. http://www.nyiso.com/public/webdocs/documents/regulatory/agreements/interconnection_agreements/imonyiso.pdf

B. PJM Proxy Buses

PJM's proxy bus pricing system has undergone a number of changes since the implementation of LMP in 1998, reflecting the construction of a new DC line (Neptune), the westward expansion of PJM, and changes in proxy bus design. The focus of this paper is on the changes in proxy bus design, but the other changes will be briefly summarized for clarity. First, the construction of the Neptune line (a controllable line between PJM and New York) that became operational on July 1, 2007, resulted in the creation of an additional proxy bus for the scheduling of transactions on this line.

Second, the expansion of PJM has led to changes over time in the identity of proxy buses, also referred to as interface pricing points, as the identity of adjacent control areas has changed. PJM initially had two NYISO proxy buses, a First Energy proxy bus, an APS proxy bus and a VACAR proxy bus. When APS joined PJM in 2002, the APS proxy bus was eliminated, and Duquesne and AEP Proxy buses were added.

With the integration of Com Ed into PJM on May 1, 2004, the number of external pricing points rose from 6 to 23. The integration of AEP and Dayton on October 1, 2004 enabled PJM to eliminate many of these pricing points and the number of external pricing points fell to 9.[34] These were the Northwest (Wisconsin-Wisconsin Electric Power, Alliant East, Alliant West, and MEC); OVEC (Ohio Valley Electric Corporation-internal to PJM),[35] DLCO (Duquesne balancing authority area internal to PJM); NYISO; Ontario; MICHFE (Michigan Electric Coordinated System, First Energy); Southwest (Central Illinois Light, Indianapolis Power and Light, Ameren, Cinergy, East Kentucky Power Cooperative, LG&E and TVA) and Southeast (Carolina Power and Light, Duke Power, and Dominion Virginia Power). It is noteworthy that PJM has frequently used a single proxy bus for a balancing authority area having multiple points of interconnection with PJM and that in a number of instances PJM used a single pricing point for schedules with multiple balancing authority areas. Thus, while transactions with each external balancing authority area using the Southeast pricing point would have a contract path through that balancing authority area and be checked out with that balancing authority area, all of them would be settled at the same pricing point.

With the integration of Duquesne into PJM on January 1, 2005 the Duquesne pricing point was eliminated. On April 1, 2005 the MISO pricing point was created to reflect the creation of the MISO, and on May 1, 2005 Dominion was integrated into PJM and no longer part of the Southwest Pricing Point.[36]

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34 PJM Market Monitoring Unit, "2004 State of the Market Report," pp. 118-119, located at http://www.pjm.com/markets/market-monitor/som-reports.html.

35 Since the shutdown of the DOE facilities in OVEC in April 2003, the OVEC control area has contained more than 2,000 MW of generation and only token load. OVEC has a number of interconnection points with adjacent transmission systems but is represented as a single proxy bus by PJM for pricing purposes. PJM provides reliability coordination services for OVEC under an agreement that does not appear to be public. PJM Manual 37 Reliability Coordination, pp. 20-24, May 15, 2007.

36 PJM Market Monitoring Unit, "2005 State of the Market Report," pp. 170, 181, located at http://www.pjm.com/markets/market-monitor/som-reports.html.

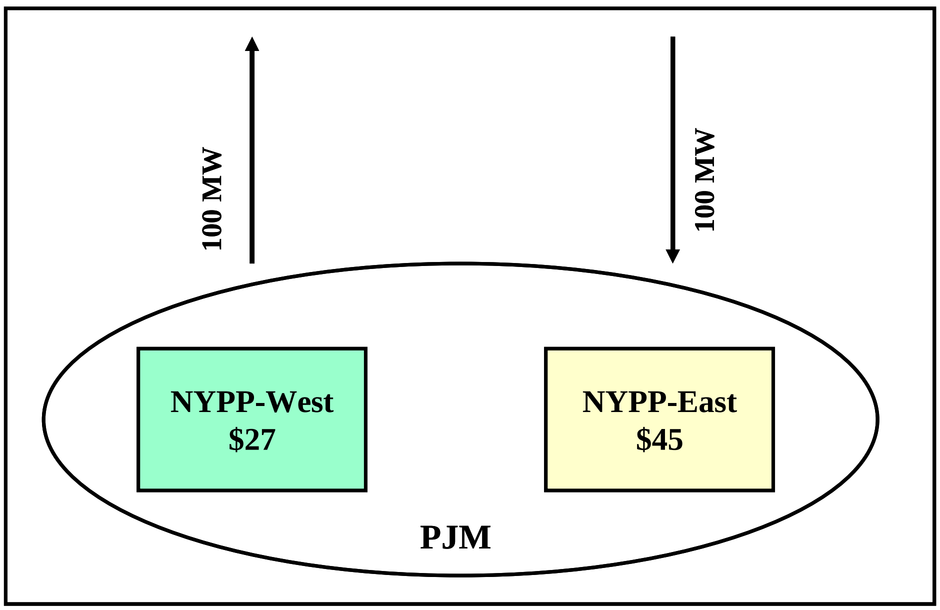
The third types of changes in PJM proxy bus design are those that are most relevant to illustrating and understanding the issues involving the appropriate number of proxy buses. These changes were not driven the construction of new lines or the expansion of PJM but were made in response to the scheduling practices of PJM market participants. There were seven changes of this type.

The first change involved the pricing of interchange with the NYISO. Until early 2001, PJM priced imports from and exports to New York based on prices determined for both a NYPP East and a NYPP West proxy bus.[37] Thus, PJM permitted market participants to designate either NYPP east or NYPP west as the source or sink of their transaction as shown in Figure 3. Moreover, the proxy buses were modeled as being at electrically distinct locations so that the price at the NYPP west proxy bus reflected the value of power delivered into or exported from western PJM, while the price at the NYPP east proxy bus reflected the value of power delivered into or exported from eastern PJM. When PJM was constrained from West to east, imports from the NYPP east bus would appear more valuable than imports from the NYPP west bus, and conversely, exports to the NYPP east bus would appear more expensive.

[37] It should be noted that neither of these locations was a point at which PJM and the NYISO metered net interchange (i.e., neither was a physical delivery point. For example, although NYSEG owns transmission lines extending down into Pennsylvania at Homer City (NYSEG used to own a share of the Homer City plant), PJM did not model imports from western New York as being delivered at the Homer City metering point, nor did PJM model its exports to western New York as sinking at the Homer City metering point.

Thus, if PJM was constrained from west to east, the proxy prices might differ as shown in Figure 3, with a PJM price at the NYPP east bus of $45/MWh, while the price at the NYPP west bus was $27/MWh. The fundamental problem with this dual proxy bus system for NYISO interchange was that since the NYISO was a single balancing authority area, PJM and the NYISO set a single interchange schedule and the designation of the source or sink of some transactions as being either NYPP east or west had no meaning for the dispatch of generation in either PJM or New York.

Figure 3
1999-2001 PJM-NYISO Proxy Bus Pricing



A fundamental problem with this dual proxy bus design for interchange schedules with the NYISO control area was that PJM and NYISO agreed upon a single interchange schedule. The fact that an export to PJM was designated to come from the NYPP East proxy bus had no meaning for the NYISO dispatch. Even if the NYISO had implemented a similar structure with a PJM east and PJM west proxy bus, those distinctions would have had no meaning for New York and PJM because they agreed upon a single interchange schedule and adjusted generation to support that single schedule. As a result of this dual proxy bus structure, in 2000 a market participant could schedule a 100MW export to NYISO from the PJM NYPP west bus and pay $27/MWh for this power and simultaneously schedule a 100MW import to PJM at the PJM NYPP east bus and be paid $45/MWh for the power, yet for the purpose of the PJM and NYISO check out and dispatch, nothing would happen. PJM would simply pay out a net of $1800 for transactions that netted to zero.

By late 2000 and early 2001, PJM and NYISO market participants had figured out that it was profitable to designate NYPP west as the sink for all exports, resulting in a lower price paid to PJM, and to designate NYPP east as the source for all imports, resulting in a higher price paid by PJM. PJM for example, calculated that over the period December 2000- February 2001, 97% of the transactions scheduled at the NYPP west proxy bus were exports from PJM and only 3% were imports, while 87% of the transactions scheduled at the NYPP east proxy bus were imports and only 13% were exports.[38] During the same hour, therefore, PJM was potentially selling power at a low price for exports sinking at NYPP west and buying power at a high price for imports sourced at NYPP east, yet there might be no net interchange with the NYISO.

Some market participants suggested that PJM's difficulties would somehow be addressed if the NYISO were to establish separate proxy buses for eastern and western PJM. Had the NYISO set up such a PJM East proxy bus, market participants could have exploited the price differentials between the NYISO Eastern and Western PJM proxy buses in the same way they exploited the dual PJM buses for the NYISO, with schedules that would have imposed uplift costs on New York customers without delivering any energy. It was this kind of inefficient scheduling by PJM market participants that caused the PJM ISO to implement a single proxy bus pricing system on the NYISO Interface in early 2001.[39]

In early 2001 PJM recognized that the dual proxy bus system for an interface with a single interchange schedule was exposing PJM consumers to significant real-time congestion rent shortfalls (and thus uplift costs) and the dual proxy bus was replaced on April 1, 2001 with a single proxy bus for the NYISO interface, consistent with the single interchange schedule agreed upon by PJM and the NYISO. Under this system, the PJM proxy bus for NYISO was initially based on an 80-20 weighting of generation located at Roseton and Dunkirk. Thus, an incremental MW of exports from PJM to NYISO was modeled as backing down .8 MW of generation at Roseton and .2 MW of generation at Dunkirk.[40]

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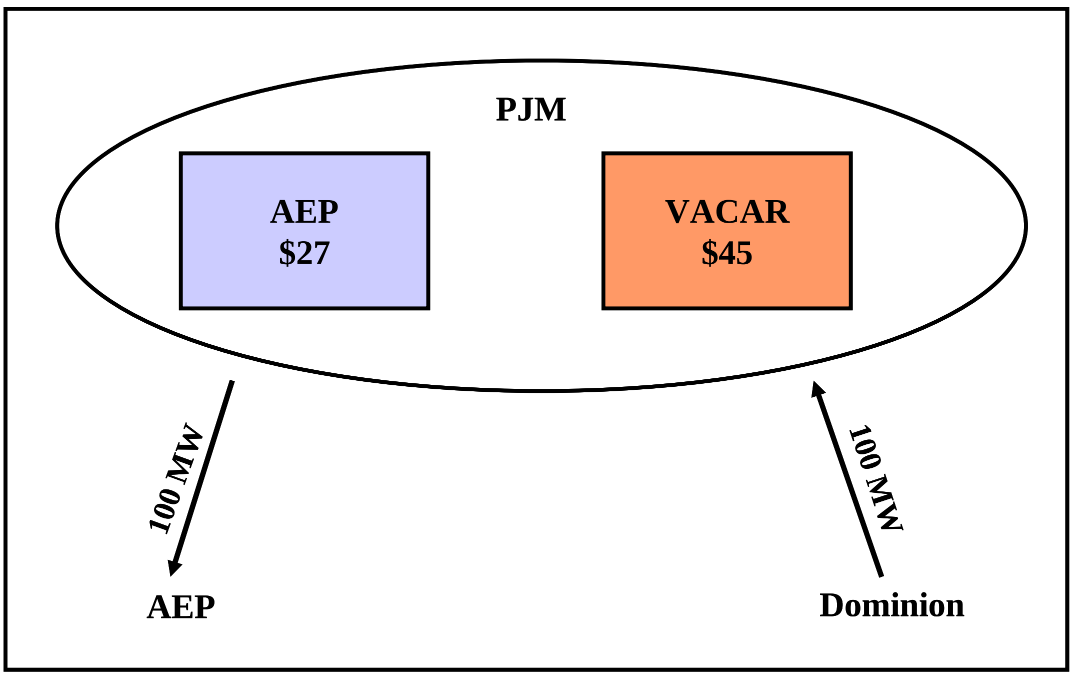
38 Andy Ott, "Congestion Charges and Loopflow," p. 5.

39 See Andrew L. Ott, "Congestion Charges and Loop Flow."

40 The proxy bus still did not coincide with any of the metering points for interchange between PJM and New York. See pjm.com/markets/energy_market/downloads/2008053_aggregate_definitions.xls

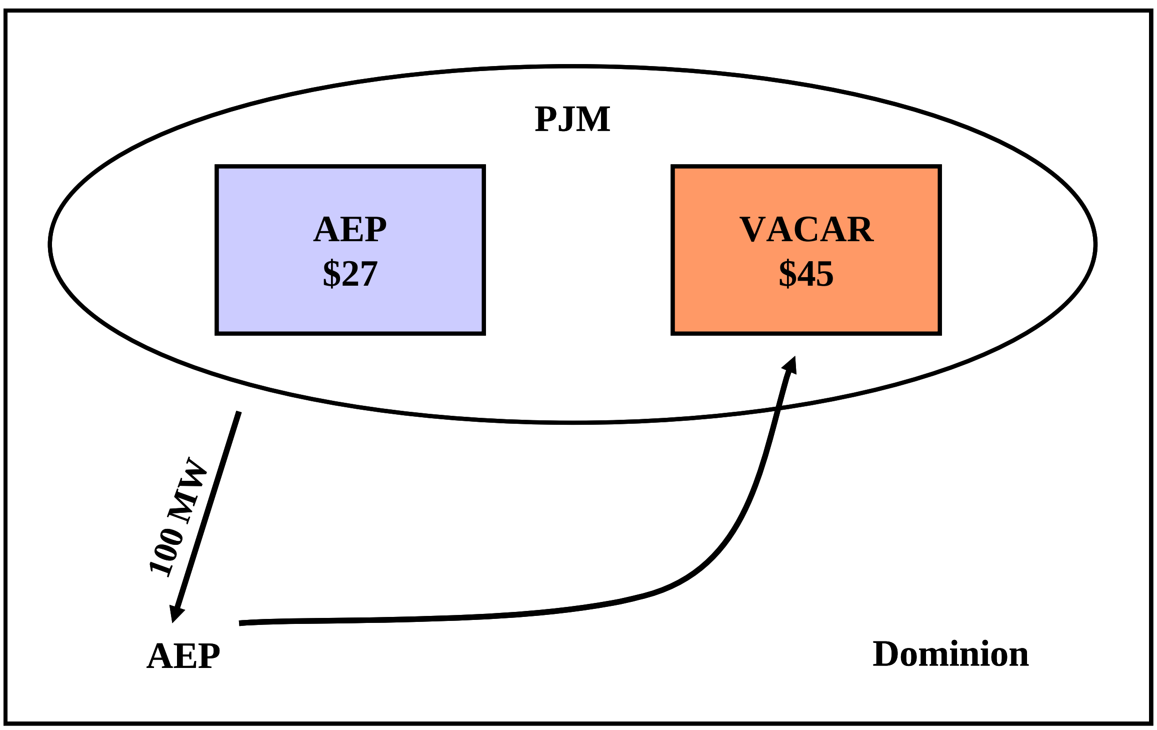
The next change in PJM proxy bus design arose not to correct problems arising from having multiple proxy buses for scheduling transactions with a single balancing authority area but from the more complex problem discussed in Section II of having individual proxy buses for individual balancing authority areas along an interface with multiple balancing authority areas. After APS joined PJM on April 1, 2002, PJM had separate proxy buses for VACAR and AEP, along its southern and western edge. Dominion (VACAR) and AEP were separate balancing authority areas so the separate proxy bus schedules had operational significance. If 100 MW imports were scheduled and cleared checkout between Dominion and PJM, then Dominion would raise its generation by 100 MW relative to its load, while PJM would lower its generation by 100 MW relative to its load, resulting in a net flow of power between the two balancing authority areas (along all parallel paths). Similarly if 100 MW of exports were scheduled and cleared check out from PJM to AEP, then PJM would raise generation by 100 MW and AEP would lower generation by 100 MW relative to its load, as illustrated in Figure 4.

Figure 4
PJM Interchange Scheduling with AEP and Dominion



The net effect of the two transactions would in effect be to raise generation in Dominion and lower generation in AEP which would produce favorable (east to west) flows through PJM when west to east constraints were binding in PJM. The difference between the $45/MWh price paid for imports from Dominion and the $27/MWh price at which power was sold into AEP would reflect the value to PJM of the flows created by raising generation in VACAR and lowering it in AEP. The problem that arose was that interchange schedules sourced in Dominion and sinking in PJM or sourced in PJM and sinking in AEP did not necessarily cause generation to rise in Dominion and fall in AEP. Suppose that the transaction sinking into PJM from Dominion was in fact sourced in AEP along a contract path from AEP into Dominion and then into PJM as illustrated in Figure 5. In this case, PJM has paid $18/MWh for transactions that had no net impact on PJM net interchange or congestion. These kind of transactions were profitable any time the price spread between PJM's AEP and VACAR bus rose above the cost of purchasing transmission along the contract path from AEP into VACAR and then into PJM.

Figure 5
Contract Path Scheduling into PJM via Dominion



In 2002 PJM found, based on e-tags, that many transactions being scheduled as sinking at the PJM VACAR interface were actually sourced in Main or ECAR and being scheduled on a contract path for delivery into PJM from VACAR. Thus, market participants were scheduling transactions along a contract path Main –VACAR – PJM, rather than along the contract path MAIN-PJM, presumably because the transmission charges to schedule along the contract path into VACAR were less than the difference in the PJM LMP price between the AEP and VACAR proxy buses. This contract path delivery location entitled the transactions to be paid the VACAR proxy bus price, but the actual electrical impact of the transactions on PJM constraints was much more like power delivered on the AEP interface.[41]

In response to this problem PJM provided, effective July 19, 2002, that transactions scheduled to sink at the VACAR proxy bus but having an e-tag indicating an ECAR or MAIN source would be paid the price for the AEP bus, rather than the VACAR proxy bus.[42]

In terms of the example in Figure 1 above, this would be equivalent to checking for tags on transactions coming in from bus F and paying the D Proxy bus price any time the tag showed an origin at D for transactions scheduled to sink at bus F. As suggested in the discussion in Section II, the limitation of PJM's initial approach was that traders could simply break their transaction into two parts, buying in balancing authority area D and selling in balancing authority area F system, then buying in balancing authority area F and scheduling a transaction into Control Area A at the F proxy bus. In terms of the actual change in generation, this would be identical to a single transaction sourced in control area A. PJM market participants may have responded in just this manner to the initial PJM rules, leading to the increased divergence between actual and modeled flows that caused PJM ultimately to combine the AEP and VACAR proxy buses as discussed below.[43]

Third, PJM shifted in January 2003 to calculating proxy bus prices for the NYISO interface using weights based on the proportion of power flowing over two tie lines on that interface. Thus, rather than the NYISO interface being priced based on the fixed 80% 20% weights established in 2001, the weights varied based on the proportion of power flowing over the two tie lines between NYISO and PJM in real-time.[44]

Fourth, effective March 1, 2003 PJM combined the AEP and VACAR proxy buses and assigned transactions sourced in a particular balancing authority area to a pricing point without regard to the contract path.[45] The problem addressed by this change was again that arising from multiple proxy buses on a common interface. The 2002 changes addressed the problem of individual transaction scheduled along a contract path from AEP into VACAR and then into PJM by using

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41 PJM Market Monitoring Unit, "Report to the Federal Energy Regulatory Commission, Interface Pricing Policy," August 12, 2002, located at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/200208-report-ferc1.pdf.

42 PJM Market Monitoring Unit, email to Energy Market Committee, August 1, 2002; "Report to the Federal Energy Regulatory Commission, Interface Pricing Policy," August 12, 2002 and email to Energy Market Committee, August 27, 2002. PJM Market Monitoring Unit, 2002 State of the Market Report, pp. 56-60, located at http://www.pjm.com/markets/market-monitor/som-reports.html.

43 PJM Market Monitoring Unit, "Report, Interface Pricing Policy, February 28, 2003, located at http://www.pjm.com/markets/market-monitor/downloads/mmu-reports/20030301-interface-pricing.pdf. PJM, "PJM Interface Pricing Changes," no date.

44 PJM Market Monitoring Unit, "2003 State of the Market Report," p. 106, located at http://www.pjm.com/markets/market-monitor/som-reports.html. PJM, "Dynamic Interfaces," January 22, 2003. "PJM Interface Price Definition Methodology."

45 PJM Market Monitoring Unit, "2003 State of the Market Report," pp. 95-96, 101-102; PJM Market Monitoring Unit, email to Energy Market Committee, January 9, 2003 "Report on Interface Pricing Policy," February 28, 2003.

etags to identify transactions sourcing outside VACAR and to determine the pricing for such transactions. Etags do not reveal where generation was actually incremented or decremented, however. To understand this, suppose that instead of a single transaction along the contract path from AEP into VACAR into PJM as portrayed in Figure 5 there were two transactions with distinct tags, one transaction from AEP sold into VACAR and another transaction sourced from VACAR and sold into PJM. The etag source of the transaction that is checked out with PJM would be VACAR, yet the net effect of the two transactions is that generation is raised in AEP, not in VACAR. Given its inability, even using etags, to distinguish interchange schedules that would produce an increase in generation within VACAR from those that would produce an increase in generation in AEP, PJM combined the interfaces for pricing purposes. PJM continued to separately conduct its check out with each control area, but for the purpose of pricing the impact of transactions on its internal transmission constraints, PJM switched to using a single pricing point, eliminating the inefficient scheduling incentives of market participants that had arisen from the dual pricing points.

Fifth, on August 1, 2003 PJM established a separate proxy bus for transactions with e-tag sources in Ontario, reflecting the differential impact of these transactions on PJM, compared to other transactions with a contract path over the NYISO interface.[46] The problem addressed by this change is that while a direct contract path schedule from the Ontario IESO balancing authority area through the NYISO into PJM might provide the highest netback to Ontario sellers, if generation were raised in Ontario, part of the power would flow around through Michigan, impacting western PJM constraints. Using the Etag to distinguish transactions sourcing in IESO from those sourcing in NYISO is similar to the approach initially used with AEP and VACAR and may ultimately be rendered ineffective by entities scheduling separate transactions sourced in Ontario and sinking in the NYISO and sourced in NYISO and sinking in PJM.

Sixth, on October 1, 2006, PJM's southeast and southwest interface pricing points were consolidated and separate proxy buses established for the pricing of imports and exports. The origin of this problem was in the westward expansion of PJM when separate proxy buses were established for the Southwestern balancing authority areas (Cinergy, TVA, etc.) and the Southeastern balancing authority areas (Duke, etc.). While these new proxy buses spanned groups of balancing authority areas, transactions scheduled from these regions turned out not to have distinguishable impacts on PJM transmission constraints, again because power scheduled to flow from the Southeast region into PJM, could in reality be supported by generation increases in the Southwestern region, scheduled along a contract path into the Southeast region and then into PJM. When PJM was constrained from west to east it and the Southeastern proxy bus price rose relative to the value of power from the Southwestern proxy bus, PJM found that import transactions were sourced with contract paths from the Southeast, but the actual powerflows over its lines were from the Southwest. Moreover, this was the case even though the application of the Southeast proxy bus price was based on the source balancing authority area on the transaction etag. As in 2002, etags were ineffective in identifying the actual location at which generation would be raised.

[46] PJM Market Monitoring Unit, "2003 State of the Market Report," p. 102.

Another feature of this change in proxy bus definition was that PJM used different bus weights to price imports and exports at the new proxy bus. This likely reflected a PJM judgment that during the conditions in which PJM would likely be exporting to this region, generation in the region of the export proxy bus would be on the margin, while during the conditions in which PJM would likely be importing from this region, generation in the region of the import proxy bus would likely be on the margin.[47]

Finally, during early 2007 PJM entered into Interface Pricing Arrangements with Duke Energy (January 5, 2007),[48] Progress Energy Carolinas (February 13, 2007)[49] and the North Carolina Municipal Power Agency Number 1 (March 19, 2007),[50] under which Duke, Progress and the North Carolina Municipal Power Agency can buy and sell power to PJM at prices calculated for generator nodes on their system (rather than the South IMP or South EXP proxy bus price).[51]

These agreements have a number of provisions limiting the circumstances in which the DECGen, PECGen, and NCMPAGen proxy prices will be applicable but the essence of these agreements is that these proxy bid prices will only be applicable if these entities are not purchasing power outside their balancing authority area. The point of these restrictions is that if these entities are not purchasing power from outside their balancing authority area, then any increase in exports to PJM must be supported by an increase in generation located within their balancing authority area. Conversely, any decrease in imports from PJM must be supported by a decrease in generation within their balancing authority area.

The DECGen, PECGen and NCMGen prices are not applicable when the relevant entities are purchasing power located outside their balancing authority area because in those circumstances there is no assurance that generation will increase within the Duke, Progress or North Carolina Municipal Power Authority balancing authority areas to support these exports to PJM.

The DECGen, PECGen and NCMGen proxy bus prices are apparently applicable when the relevant entities are selling power to buyers other than PJM located outside of their balancing authority area. If sales to PJM were accompanied by a reduction in sales to other balancing

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47 Stan Williams, "Uncompensated Parallel Flow (Loopflow) Update," August 8, 2006. PJM Market Monitoring Unit, "2006 State of the Market Report," pp. 169, 177-178, 195-199, located at http://www.pjm.com/markets/market-monitor/som-reports.html; PJM Southeast and Southwest Interface Pricing Point Consolidation Approach," August 31, 2006, located at http://www.pjm.com/etools/oasis/downloads/interface-pricing-point-consolidation.doc.

48 Andrew L. Ott letter to Lance C. Stotts re: Duke Energy Carolinas Interface Pricing Arrangements, January 5, 2007, located at http://www.pjm.com/documents/downloads/agreements/duke-pricing-agreement.pdf.

49 Andrew L. Ott letter to Robert Caldwell re: Progress Energy Carolinas, Inc. Interface Pricing Arrangements, February 13, 2007, located at http://www.pjm.com/documents/downloads/agreements/pec-pricing-agreement.pdf.

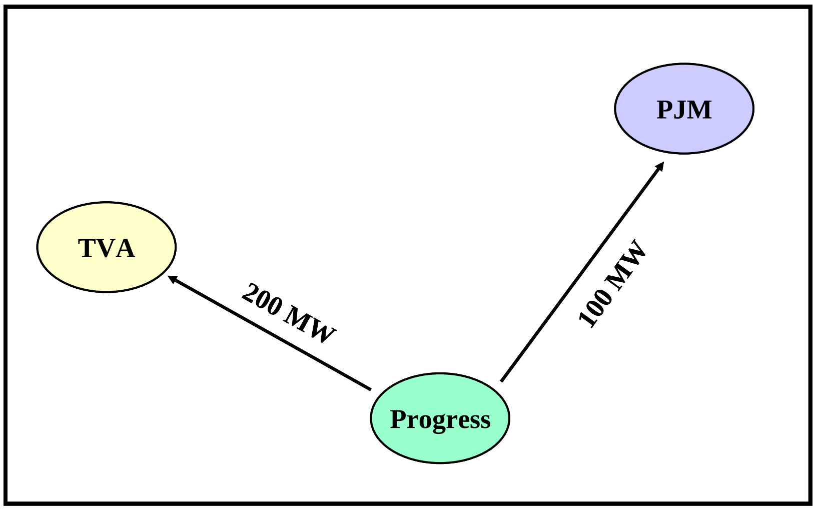
50 Andrew L. Ott letter to Clay A. Norris re: North Carolina Municipal Power Agency Number 1 Interface Pricing Arrangement, March 19, 2007, located at http://www.pjm.com/documents/downloads/agreements/electricities-pricing-agreement.pdf .

51 These agreements were also discussed in the 2007 State of the Market Report, pp. 212-213, , located at http://www.pjm.com/markets/market-monitor/som-reports.html.

authority areas, the net effect on PJM would be the same as if the import were sourced in the other balancing authority area.

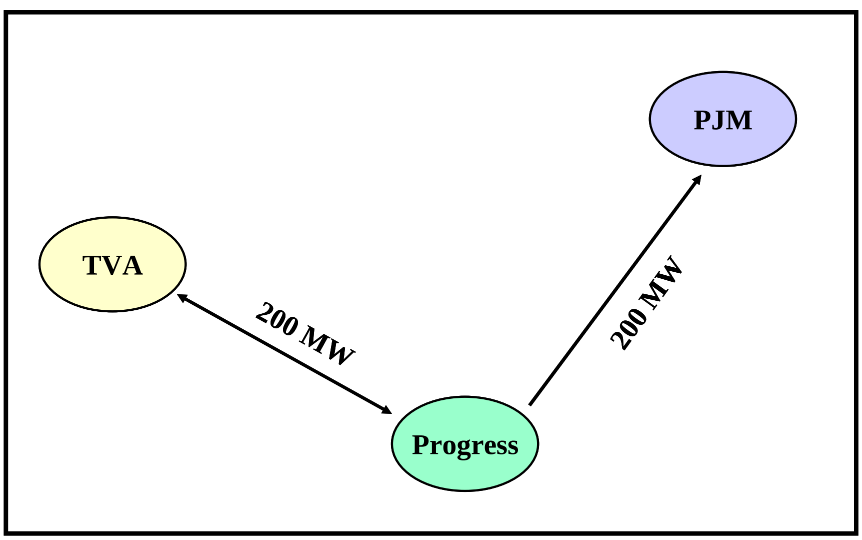
For example, suppose that in hour 1 Progress Energy was selling 100 MW to PJM and 200 MW to TVA, as shown in Figure 6.

Figure 6
Hour t Interchange Schedules



Now suppose that in hour 2 Progress Energy increased its exports to PJM to 200, offset by a 100 MW reduction in its exports to TVA, as shown in Figure 7.

Figure 7
Hour t+1 Interchange Schedules



The net change between hour 1 and hour 2 is a 100 MW increase in TVA generation, yet the PECGen price would apparently apply under the interface pricing agreement.

Perhaps the reason for the lack of provisions governing exports from the relevant control areas is a combination of an expectation that market prices will generally disfavor such exports and the likelihood that such exports to TVA would be providing PJM with favorable counterflow on its west-to-east constraints so it may not be in the interest of PJM transmission customers to discourage such exports. These considerations may not apply in other contexts, so other entities considering the use of provisions similar to PJM's interface pricing arrangements may need to have rules for periods in which exports as well as imports are occurring.

Under the agreements, Duke, Progress and the North Carolina Municipal Power Agency No. 1 agreed to provide confidential and auditable data to PJM concerning their load, aggregate system generation, aggregate energy sales and purchases on a one-minute or shorter basis.[52]

One principle that PJM adhered to throughout these changes in proxy bus definitions is that while these changes were implemented prospectively for the pricing of interchange transactions, PJM continued to calculate prices for the original proxy bus definitions and previously sold FTRs sinking at the original proxy bus locations continued to be settled based on these prices for the original proxy bus location.[53]

On the other hand, even more than in New York, the PJM experience shows the need to change proxy bus definitions over time, both to reflect the addition of controllable lines, changes in PJM boundaries and to improve pricing based on experience and the behavior of market participants.

C. ISO-NE Proxy Buses

The ISO-NE currently has six proxy buses for interregional schedules, three with the NYISO, two with the Hydro Quebec, one with New Brunswick.[54]. The ISO-NE proxy bus for its AC inter-connects with NYISO is located at Roseton. Like the NYISO, ISO-NE has a separate proxy bus located at Shoreham on Long Island for power scheduled to flow on the Cross Sound Cable, which is a controllable line (DC), and also has a separate proxy bus for schedules on the PAR controlled 1385 line connecting ISO-NE and Long Island. ISO-NE also has separate proxy buses for two distinct its DC interconnects with Hydro Quebec at Highgate and Sandy Pond. Finally, it has a proxy bus located at Keswick for deliveries from New Brunswick.

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[52] See the agreements cited in footnotes 51-53.

[53] See for example, "PJM Southeast and Southwest Interface Pricing Point Consolidation Approach" August 31, 2006.

[54] "ISO New England Calculation of TTC for External Interfaces and ATC for PTF Interfaces," Version 2.0, Issued on December 15, 2007.

IV. CONTROLLABLE LINES AND PROXY BUSES

The problems of applying multiple proxy bus pricing systems to scheduling a single level of tie line flows arise because the actual real-time flows are not affected by the proxy bus scheduling decision. This is a characteristic of schedules over open ties for which there is a single schedule for net flows over all of the tie lines. These problems do not arise for schedules over controllable lines if the system operator or line operator holds the actual flows over the line to match the schedule.

If the system operators dispatch generation to maintain separate tie line schedules and move generation up and down at different combinations of locations in order to increase or decrease flows on those tie lines, then the impact of these changes in schedules would be best modeled by establishing separate proxy buses for changes in interchanges over the distinct tie lines or sets of the lines. For example, if the system operators dispatch generation to maintain a separate tie line schedule on a controllable line, then market efficiency is improved by establishing a distinct proxy bus location for that line.

This practice has been followed by PJM, NYISO and ISO-NE, which have all established additional proxy buses to price schedules over controllable lines (Cross Sound Cable, 2005; Neptune, 2007; and 1385 Line, 2007).