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Proxy Buses, Seams and Markets

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I. OVERVIEW

The most fundamental of all seams issues is the need of adjacent dispatch areas to coordinate their net interchange. Under market-based systems, it is also necessary to value interchange power. All of the existing LMP based pricing systems currently utilize proxy bus mechanisms for representing and valuing interchange power. A fundamental feature of LMP pricing systems is that location matters, and this is true for external as well as internal generation. The location and number of proxy buses used by LMP pricing systems to model imports and exports has therefore been a subject of continuing discussion. This paper explains and describes proxy bus pricing systems and discusses the issues relating to the choice of proxy bus location, as well as the number of proxy buses. The paper focuses on four important features of proxy bus pricing and scheduling systems:

- Proxy bus pricing systems based upon network models that include the transmission system in adjacent dispatch areas.
- The purpose of modeling changes in net interchange at a proxy bus is to approximate the combined effect of all changes in generation in an adjacent dispatch area that would occur in response to a change in scheduled net interchange.
- The appropriate number of proxy buses depends 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.

These features are relevant today with all transactions scheduled by market participants and will continue to be relevant under virtual regional dispatch in which ISOs also play a role in coordinating net interchange.

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II. PROXY BUS SCHEDULING SYSTEMS

A. General Principles

A proxy bus in LMP based transmission pricing systems is a location at which imports from, and exports to, adjacent dispatch regions are modeled for pricing purposes. That is, the proxy bus is the location at which the dispatch and pricing models assume that generation in the adjacent dispatch region is increased to support exports from that dispatch area and decreased to accommodate imports into that dispatch area. In LMP pricing systems the proxy bus is not simply an interface scheduling location modeled as radially connected to the ISO-coordinated transmission system (unless, of course, the adjacent system is radially connected).[1] 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 be modeled as potentially impacting the flows on multiple tie lines (lines connecting the dispatch regions).[2] External proxy buses are locations on this external transmission grid that have been selected for representing the likely impact on transmission system flows of the combined effect of all changes in generation that would occur to support changes in the level of scheduled net interchange.

The distinction between internal generation and load that is 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 does not control the location at which generation in an adjacent dispatch region is increased or decreased to support changes in net interchange. That is, if the system operator in region A schedules an additional 100 MW of imports from adjacent dispatch region B, the system operator of region A would not determine which specific generators in region B would be incremented to support the 100 MW change in net interchange. This would be determined by the system operator dispatching region B. The resulting pattern of flows over the tie lines, and the impact on internal transmission constraints may, however, depend on the specific location at which generation will be incremented in dispatch region 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 of dispatching region A must therefore make assumptions regarding the location at which the system operator for dispatch region B would increment generation to support exports to dispatch region A. In an LMP system, an external proxy bus is, in essence, the location at which it is assumed that generation in the adjacent dispatch region will be dispatched up and down with changes in scheduled net interchange.

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1 The California ISO uses this alternative approach to representing external scheduling locations.

2 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 will be modeled as spread out over the transmission grid of the adjacent dispatch system, thus potentially giving rise to loop flows. The proxy bus simply models the location at which *marginal* changes in generation are assumed to occur in response to changes in net interchange.

It is also important in understanding the role of proxy buses to recognize that system operators cannot use the observed actual flows on interregional tie lines to assign a source for interregional transactions or changes in net interchange. This is because the flows observed on interregional tie lines generally depend not only on net interchange between the directly interconnected dispatch areas (and the location of the generation within those dispatch areas used to support the net interchange) but also on the pattern of generation within each of the connected dispatch regions (which create loopflows through the adjacent interconnected dispatch regions) and the pattern of generation throughout the rest of the AC interconnection (which creates additional loopflows on the 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 net interchange between NYISO and PJM, 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). It is therefore not possible to infer anything from the pattern of tie line flows about the location of the generation in the exporting dispatch area that was used to support net interchange.

Because external proxy buses are generation locations in a model of the transmission network, an LMP based system can calculate an LMP price for each external proxy bus. The LMP price at a proxy bus will reflect the impact of net generation at the Proxy bus location on transmission constraints within the region dispatched by the ISO.[3] Importantly, under current pricing and dispatch procedures, 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 in which the proxy bus is located, because those constraints would be managed by a different ISO.[4]

PJM, NYISO and ISO-NE all use proxy bus methods to model and price net interchange with some or all adjacent dispatch regions.[5]

3 In the case of the NYISO the determination of the LMP price at the proxy price differs from the calculation of internal LMP prices in that the LMP price at the proxy bus does include the marginal cost of losses incurred on flows from the proxy bus to the border of the NYISO control area, but includes only the cost of losses that would be incurred within the NYISO.

4 Procedures are under discussion for taking account of constraints in adjacent control areas in the dispatch in some circumstances. See PJM and MISO Proposal, Congestion Management Seams Issue White Paper, Version 2a, January 14, 2003; PJM and MISO Congestion Management Seams Issue Update, NERC Operating Committee Special Meeting, February 4, 2003; PJM ISO and the Midwest ISO, Managing Congestion to Address Seams, April 16, 2003; and Michael D. Cadwalader, Scott M. Harvey, William W. Hogan and Susan L. Pope, "Market Coordination of Transmission Loading Relief Across Multiple Regions, November 18, 1998. The NYISO and PJM have implemented a limited redispatch program, the Interregional Congestion Management Pilot Program, described in Section 5.1.1 of the NYISO Services Tariff.

5 The California ISO uses a contract path model for scheduling interchange and does not use a proxy bus methodology.

B. NYISO Proxy Buses

The NYISO has had four proxy buses, one each for modeling interchange with ISO-NE, the IMO, PJM and HQ.[6] The NYISO proxy bus for ISO-NE is Sandy Pond. Thus, the NYISO models an increase in imports from ISO-NE as being supply by increased generation at Sandy Pond, while increased exports from NYISO to ISO-NE are modeled as backing down generation at Sandy Pond. Sandy Pond is the location of the ISO-NE end of a DC interconnection between HQ and NEPOOL. The NYISO proxy bus for PJM is Keystone. Keystone is the location of a large coal-fired generator in PJM. The NYISO proxy bus for HQ is Chateauguay, which is the location of the radial interconnection with HQ, and the NYISO proxy bus for IMO is Bruce, which is the site of substantial nuclear generation. Thus, when an additional MWh of imports from PJM is scheduled in the NYISO day-ahead market, 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. The selection of the NYISO PJM proxy bus was 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. In addition, the Shoreham bus will serve the functions of a proxy bus for scheduling flows on the Cross Sound cable.

The NYISO day-ahead, hour-ahead and real-time dispatch software models treat phase angle regulator (PAR) schedules on the tie lines as fixed; that is, they assume that the PARs are being moved to hold flows to the schedule and the schedule on the PAR controlled line is independent of the overall level of net interchange. Since most of the tie lines between NYISO and PJM in eastern PJM are PAR controlled, this assumption means that the pattern of inter-regional flows does not vary much in NYISO models with changes in the location of the incremented or decremented generation in PJM, because most of the flows are determined by the assumed or actual settings of the PARs. Since PAR schedules may significantly impact transfer capability with adjacent control areas, it is important to assume realistic DAM PAR schedules to ensure that DAM transaction schedules are realizable in real-time operation. These scheduling assumptions are consistent with the Security Coordinator obligation for predicting values of realistic forecast transfer capabilities. This PAR modeling issue is further complicated by the reality that the PARs between NYISO and PJM are not controlled by NYISO but by PSE&G and PJM.

C. PJM Proxy Buses

PJM currently has four proxy buses. A NYISO proxy bus, a First Energy proxy bus, an AEP-VACAR proxy bus, and a Duquesne proxy bus.

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. In early 2001, PJM moved to a single proxy bus for pricing imports from and exports to New York. Under this system, the PJM proxy bus for

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[6] See NYISO Technical Bulletin 37, May 19, 2000.

NYISO was initially based on an 80-20 weighting of generation located at Roseton and Niagara. 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 Niagara. In addition, prior to the 2002 operation of PJM West, PJM had three external proxy buses in the South and West, Vacar, APS and First Energy. When APS was incorporated into PJM West, the APS proxy bus was replaced by proxy buses for AEP and Duquesne. The AEP and VACAR proxy buses were then combined in early 2003 and PJM moved to dynamic determination of proxy bus weights based on line flows, and this approach is applied to the NYISO proxy bus as well.[7]

D. ISO-NE Proxy Buses

The ISO-NE proxy bus for its AC inter-connects with NYISO is located at Roseton. 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). ISO-NE also has proxy buses for 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.

III. PROXY BUS PRICING ISSUES

A. Overview

An important market design issue involving proxy buses in LMP based transmission pricing systems is the determination of the appropriate number of proxy buses for representing transactions with adjacent control areas or dispatch regions.

The choice of a single versus multiple proxy bus for scheduling inter-control area transactions is an often misunderstood element of electricity market design. In this section we first illustrate the operation of a single proxy bus system used to manage a single tie line schedule. In this example, it is seen that a proxy bus system can fail to produce the optimal level of net interchange if:

- The proxy bus, and thus the assumed location of marginal generation in the adjacent dispatch area, does not correspond to the actual location of marginal generation in the adjacent dispatch area;
- One or both of the dispatch areas have 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 dispatch area to support changes in net interchange.

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7 "Dynamic Interfaces," PJM Energy Market Committee, January 22, 2003; and PJM Market Monitoring Unit, Report Interface Pricing Policy, February 28, 2003.

We then turn to a discussion of the operation of multiple proxy bus systems. It is seen that multiple proxy bus systems provide market participants with financial incentives to schedule transactions such that the proxy bus does not reflect the actual location of the generation that would be dispatched to support the transaction. Moreover, this effect is systematic, causing a dispatch system employing a multiple proxy bus system to schedule a single level of tie line flows to incur uplift costs.

Finally, we turn to a related case, in which there is only one proxy bus in each adjacent control area or dispatch region, but there are multiple, interconnected adjacent control areas or dispatch regions. It is seen that this situation gives 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.

B. Single Proxy Bus System

Under a single proxy bus system, all interchange scheduled with an adjacent dispatch area is assumed to result in changes in net generation at the location of the proxy bus. Thus, increased imports from that dispatch area are modeled as resulting in an increase in generation at the proxy bus location and decreased imports (or increased exports) result in a decrease in generation at the proxy bus location. If there were no binding transmission constraints within the importing dispatch area, the location at which generation would be increased in the adjacent dispatch area would be of no consequence to the importing dispatch area, as changes in the pattern of flows would not matter to the importing dispatch area, while the exporting dispatch area would take its transmission constraints into account in its dispatch to support the increased exports.

A potential problem arises if one or both of the dispatch areas have 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 dispatch area to support changes in net interchange. If the difference between the proxy bus location and the actual location at which generation is incremented is such that the actual change in generation has a less favorable impact on the binding transmission constraint than does generation located at the proxy bus, then the proxy bus representation would cause the system operator to schedule more imports from the adjacent dispatch region than is actually economic, or perhaps even feasible. This situation would result in real-time revenue inadequacy for the importing ISO as day-ahead or hour-ahead schedules would have to be backed down or accommodated through real-time redispatch due to infeasibilities. 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 actually be economic. Under most ISO settlement systems this latter failure would not produce revenue inadequacy in ISO settlements but would mean that load has not have been met at least cost.

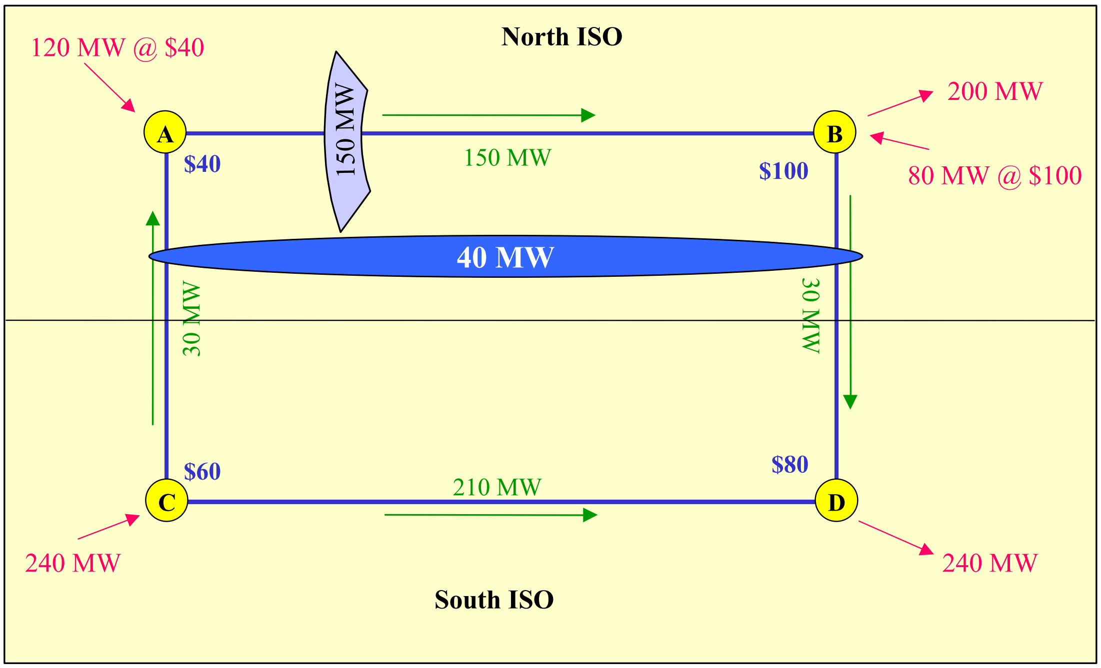
The choice of proxy bus location should be guided by several considerations. First, the location of load and fixed generation is irrelevant for the marginal analysis of changes in line loadings by the importing region. The only generation that is relevant to the scheduling of incremental net interchange and the selection of a proxy bus is the location at which marginal generation is dispatched up or down in response to changes in the level of net interchange. Second, it is desirable that the location of external proxy bus be consistent with representing the impact on tie line flows resulting from 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 available generation. The lowest cost undispatched marginal generation in an adjacent dispatch are not fixed, but instead depends on the level of load within the exporting dispatch region and the location of transmission constraints within the adjacent dispatch region. The reality is that the location of marginal generation within an adjacent dispatch region will move around with changes in load and transmission constraints and no fixed proxy bus can ever provide an exact representation of marginal generation sources.

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. PJM has taken a step in this direction with some of the changes it has recently introduced as discussed below.

The operation and limitations of a fixed single proxy bus pricing system can be illustrated with a simple example. Figure 1 portrays a simple 4-bus, two-ISO system, with prices calculated from the standpoint of the North ISO.[8] It can be seen that the line A-B within the North ISO is at its limit, and given this constraint, and given the generation offer prices at A and B, the value of injections at C and D would (from the standpoint of North ISO) be \$60 and \$80/MWh.

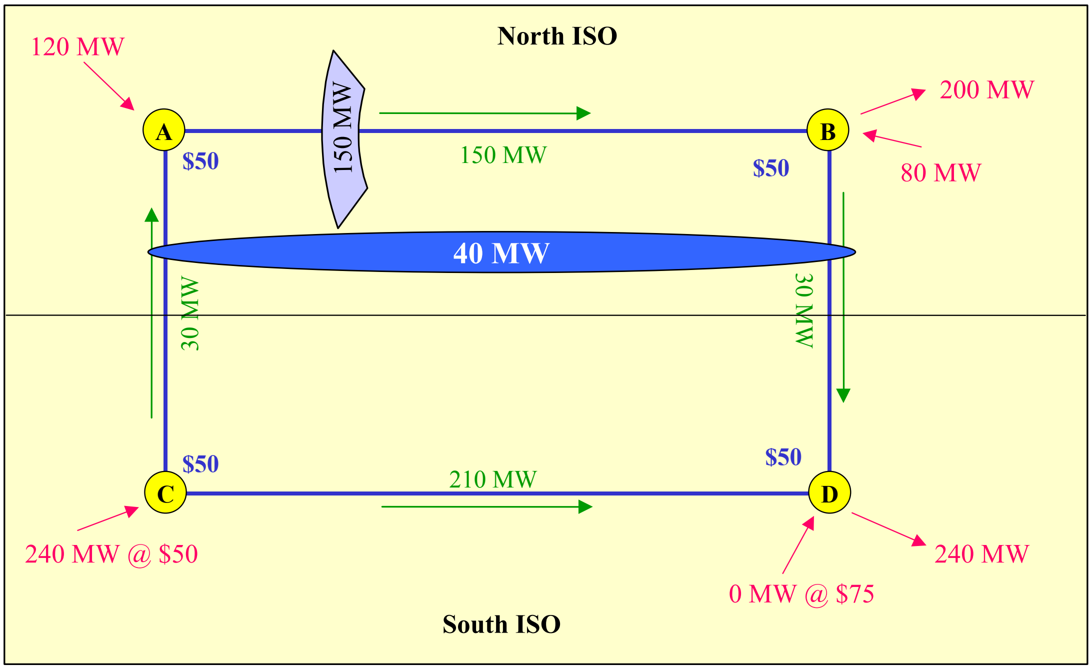
[8] For simplicity, all of the lines are assumed to have equal reactance and zero resistance and the example ignores post-contingency constraints.

Figure 1
North ISO Prices



No constraints are binding within the South ISO, and the LMP prices as calculated by the South ISO would be the same everywhere and equal to $50, set by a generator at C; as shown in Figure 2.

Figure 2
South ISO Prices



We begin by assuming that North ISO's proxy bus for South ISO is located at C. The value to the North ISO of exports from South ISO would then be determined by the LMP price at C, as calculated by North ISO. It can be seen in Figure 1 that the price at C would be $60, well in excess of the cost of marginal generation in South ISO, which is $50 generation located at C. Market participants would therefore schedule exports from South ISO to North ISO in the day-ahead market, until the 40 MW interface limit was binding as shown in Figure 3.

Figure 3
North ISO Proxy Bus at C
North ISO Prices

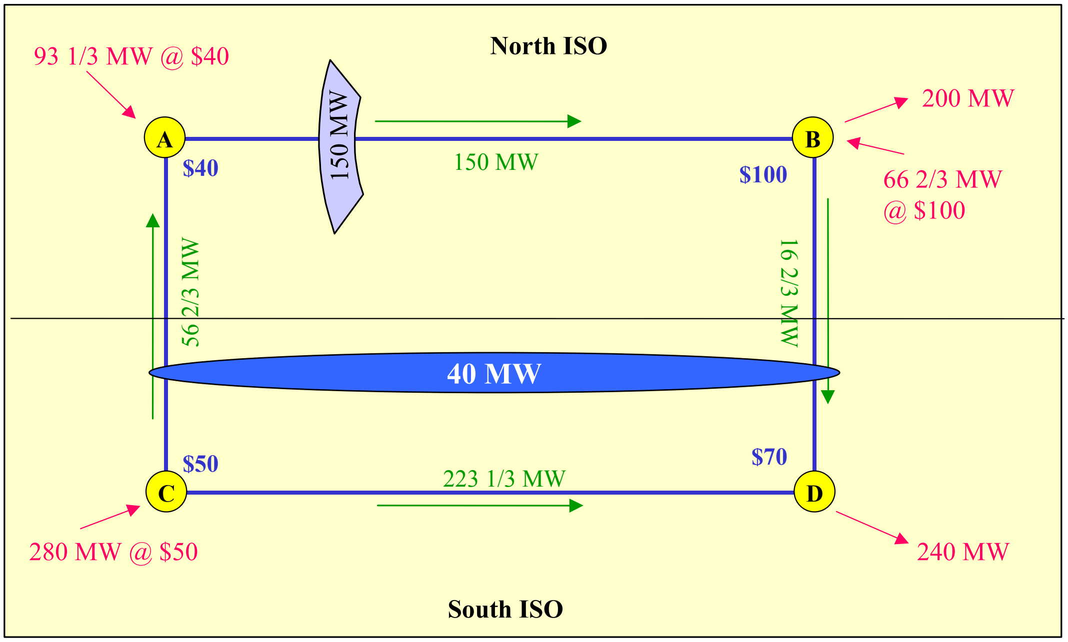


Table 4 shows that these imports would reduce the cost of meeting load in North ISO by $400.

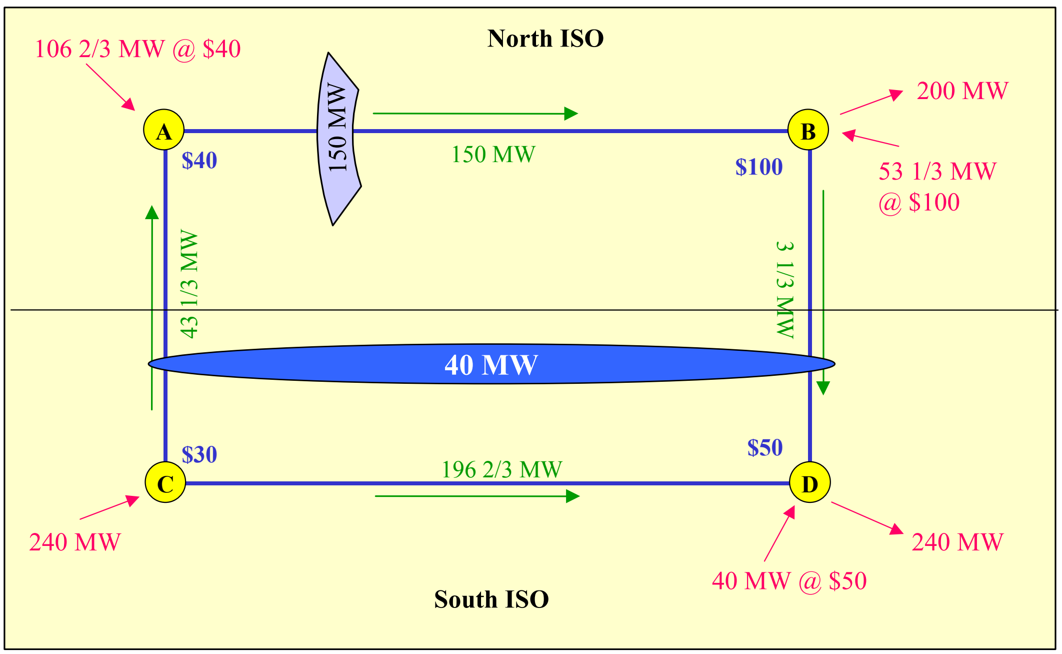
Table 4
Cost of Meeting Load
North ISO Proxy Bus at C

MWh	$/MWh	Total $
-26 2/3 MWh @ A	$40	-$1,066.67
+40 MWh @ C	$50	+$2,000.00
-13 1/3 MWh @ B	$100	-$1,333.33
Net 0 MWh		-$400.00

In real-time South ISO would dispatch its generation to support exports of 40 MW to North ISO. Since the lowest cost generation in South ISO is located at C, South ISO would dispatch up generation at C to support exports. In this case no problems arise under the single proxy bus system because the proxy bus is located at C and the marginal source of generation is also at C.

Now consider the circumstance in which bus D is defined as the proxy bus. The price at D would be $50,[9] and again 40 MW of imports would be scheduled from South ISO in the day-ahead market. The modeled flows would be as shown in Figure 5, and more high cost generation at B could be backed down than in the prior case.

Figure 5
North ISO Proxy Bus at D
North ISO Prices



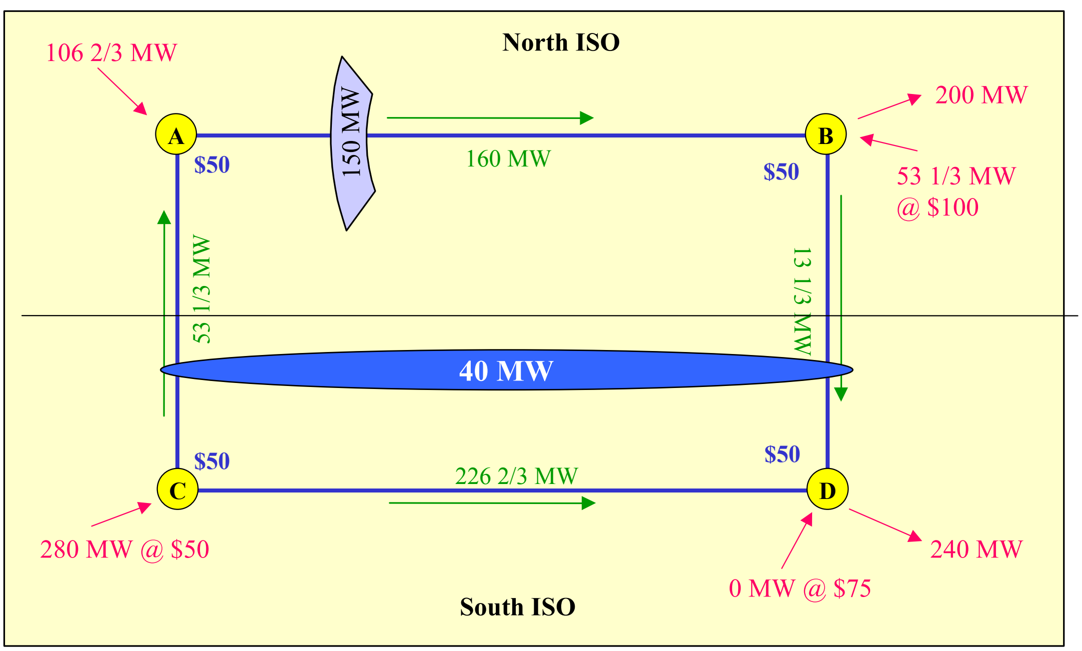
It can be seen in Table 6 that the overall cost savings from scheduling imports supported by generation at D would appear to be $1,200.

9 It should be noted that the price at D has fallen from $70/MWh in Figure 3, to $50/MWh, and from $50/MWh to $30/MWh at C. This reflects the change in the location at which the marginal generation is modeled. Thus, sales at D appear profitable in Figure 3 precisely because that is not the location of the proxy bus and $50/MWh offers at C determine the price at D.

Table 6 Cost of Meeting Load North ISO Proxy Bus at D		
MWh	**$/MWh**	**Total $**
-13 1/3 MWh @ A	$40	-$533.33
-26 2/3 MWh @ B	$100	-$2,666.67
+40 MWh @ D	$50	+$2,000.00
Net 0		-$1,200.00

The problem with this proxy bus representation is that in real-time South ISO would not dispatch up the $75 generation at D to support these exports to North ISO but would instead dispatch up the lower cost generation located at C. Thus, the actual pattern of flows in real-time would be as shown in Figure 7, and line A-B would be overloaded if North ISO dispatched its internal generation as portrayed in Figure 5.

Figure 7
South ISO Dispatch with Proxy Bus at D
South ISO Prices



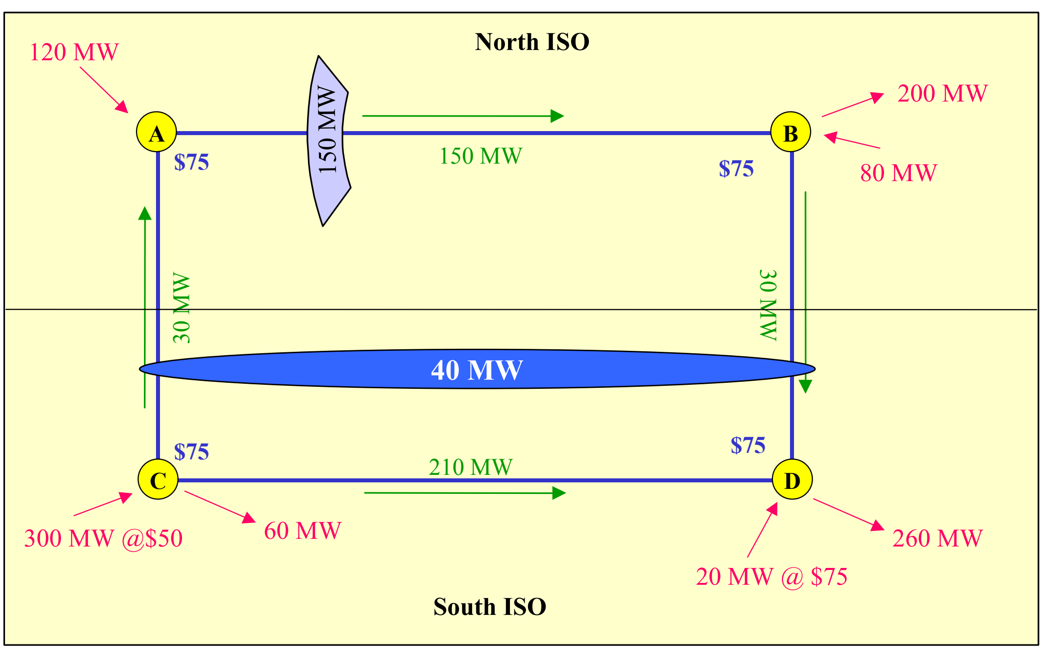
North ISO would therefore have to dispatch up generation at B and dispatch down generation at A in real-time, resulting in the same dispatch portrayed in Figure 3. The ISO would therefore incur an $800 revenue inadequacy in real-time.

Table 8
Real-Time Revenue Inadequacy – North ISO

MWh	$/MWh	Total $
-13 1/3 MWh @ A	$40	-$533.33
+13 1/3 MWh @ B	$100	+$1,333.33
Net		+$800.00

These problems would appear to be avoided if North ISO simply located its proxy bus at C. The reality is more complex. The proxy bus system will only result in fully efficient outcomes if the proxy bus is located to reflect the source of marginal generation, which can vary. A second potential problem under a single proxy bus pricing system can be illustrated by assuming that there is only 300 MW of generation located at C and that once load in South ISO rises above 300 MW, generation at D is dispatched on the margin. To keep the example simple, we will assume that 60 MW of the additional load is located at C and 20MW at D, so the net flows are as portrayed in Figure 9.

Figure 9
South ISO Dispatch and Prices at High Load



If the supply of $50 generation at C is thus limited, the incremental cost of generation within South ISO would be $75, reflecting the cost of generation at D that is being dispatched to meet load. At a cost of $75, it would not be economic for North ISO to schedule imports from South ISO if North ISO modeled the proxy bus at C, because the proxy bus price would be only $60, as seen in Figure 1, above. In fact, however, it would be economic to schedule 40 MW of imports from South ISO that are supported by generation at D, backing down generation at A and B as shown in Figure 10. This was also illustrated in Figure 1 above, as the proxy price at D would be $80, which would exceed the offer price of supply from South ISO.

Figure 10
Imports Supported by High Cost Generation at D

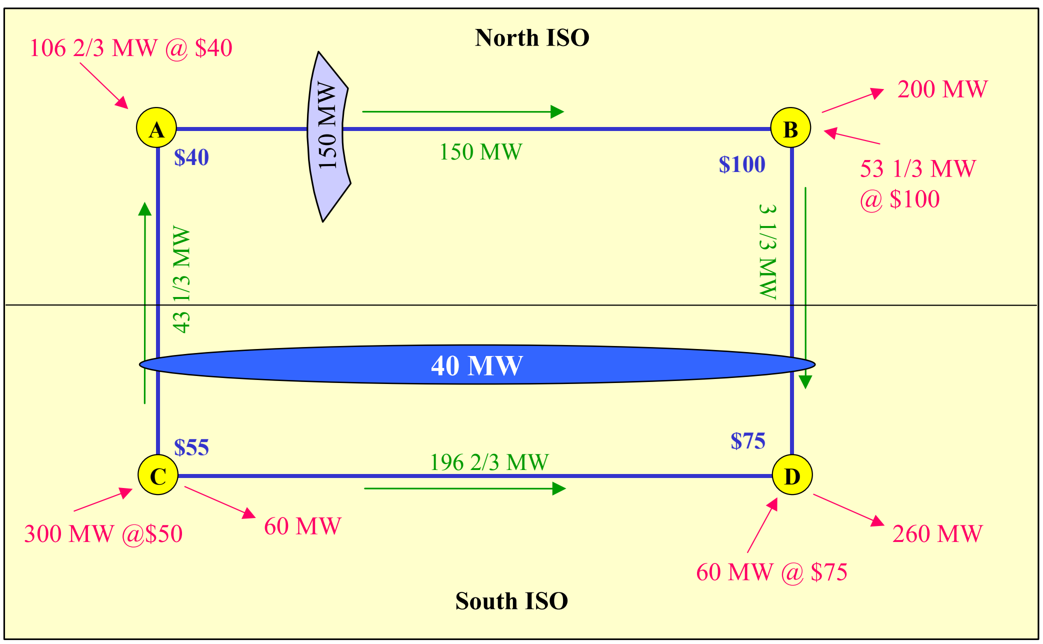
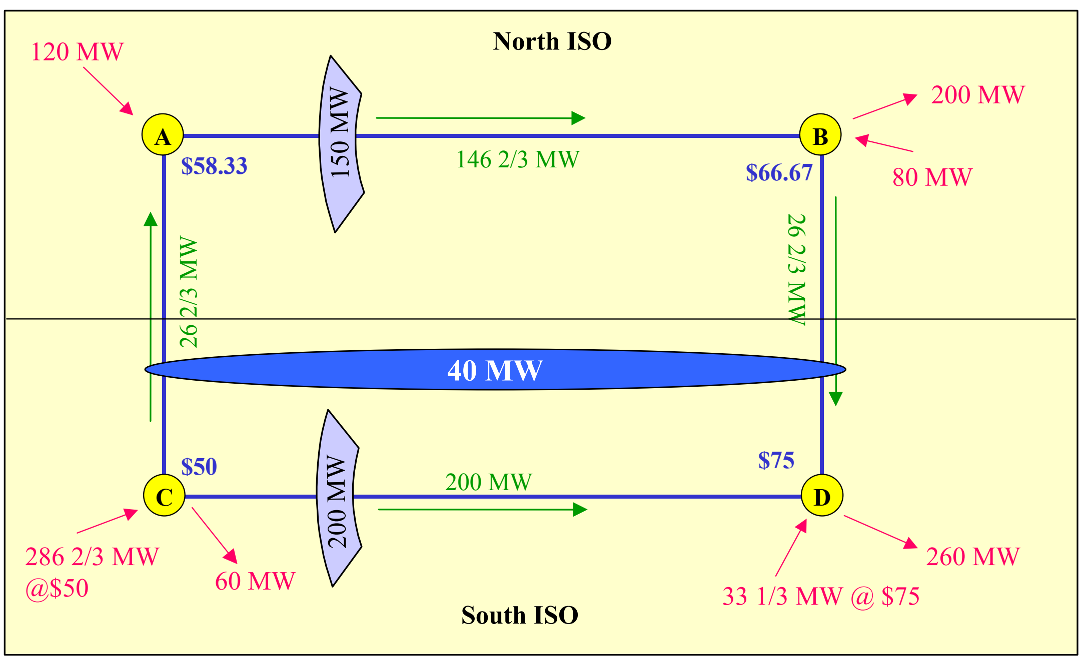


Table 11 shows that the scheduling of imports supported by generation at D in South ISO would reduce the cost of meeting load in North ISO by $200 (compared to the dispatch portrayed in Figure 1) but this outcome would not be economically sustainable if the proxy bus were located at C.

Table 11 Cost of Meeting Load with High Cost Imports		
MWh	**$/MWh**	**Total $**
-13 1/3 MWh @ A	$40	-$533
-26 2/3 MWh @ B	$100	-$2,667
+40 MWh @ D	$75	+$3,000
Net		-$200

The coordination of interchange based on proxy buses becomes even more complex if both dispatch areas have binding internal constraints that are impacted both by net interchange and the internal redispatch of the adjacent control area. These problems are illustrated in Figure 12 in which the internal dispatch of South ISO is limited by a 200 West-East transmission constraint. The existence of such a constraint would have several impacts. First, it would limit South ISOs dispatch of generation at C to 286 2/3MWh as portrayed in Figure 12.[10]

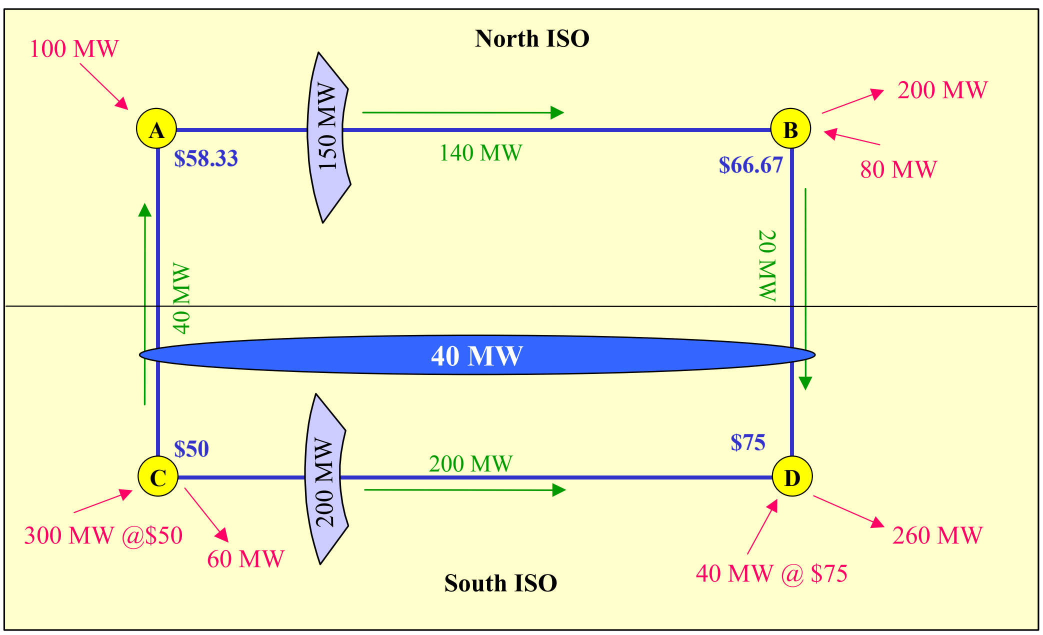
Figure 12
Constraints in South ISO



10 Given the injection of 120 MW at A and withdrawal at B within North ISO.

Second, such an internal constraint would cause South ISO to dispatch generation at both C and D to support exports, and the cost of exports would therefore differ from the South LMP offer price at either C or D as shown in Figure 13. Third, South ISOs generation dispatch to support exports to North ISO and the cost of those exports would differ depending on the location at which South ISO anticipates that generation would be backed down in North ISO. It can be seen in Figure 13 that exports from South ISO that are assumed to back down generation at A would have a cost of $58.33, while exports from South ISO that are assumed to back down generation at B would have a cost of $66.67. Any fixed proxy bus system assumes that generation in the adjacent dispatch region will always be moved at the some location to support a change in net interchange, but this will not necessarily be the case. The resulting differences between the actual and expected changes in dispatch have the potential to give rise to uplift or departures from a least cost dispatch.

Figure 13
Exports from a Constrained South ISO



C. Multiple Proxy Bus System

An important market design issue involving proxy buses in LMP based transmission pricing systems is the determination of the appropriate number of proxy buses for representing transactions with adjacent control areas or dispatch regions. 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 dispatch region, market participants would be able to choose which proxy bus to utilize for scheduling individual transactions between the dispatch regions, but system operators would, by definition, dispatch the system without regard to the proxy bus selected for scheduling and pricing purposes. This ability of market participants to vary the proxy bus used for dispatch and pricing might at first blush appear to be useful in addressing the limitations of a single proxy bus system described above. In fact, multiple proxy buses for scheduling a single level of the line flows provide market participants with a financial incentive to select the proxy bus used for transaction scheduling based on the difference between the prices at these proxy buses, but this incentive 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 dispatch region 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 power by both the exporting and importing dispatch regions 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 and decremented to support the change in net interchange. If the transmission system in either dispatch area were constrained, however, the value of the power would depend on the location at which generation were incremented and decremented. Under a multiple proxy bus system for scheduling a single level of tie line flows, market participants will compare the export and import prices associated with each proxy bus pair and select the pair providing the largest margin. The problem from the standpoint of the system operator and the market as a whole is that this designation has nothing to do with how the power will actually flow and is likely to result in a revenue shortfall for ISO coordinated markets, raising uplift costs.

In the context of transactions between New York and PJM, the issue has been that whether a market participant designated an export as destined for the NYPP E or NYPP W proxy bus under PJM's initial multiple proxy bus system did not change how PJM would dispatch PJM generation to supply the generation to support such a change in net interchange.[11] In either case, PJM would dispatch generation at least cost, given any binding transmission constraints within PJM, to supply the net interchange. It has been the NYISO's expectation that this least cost dispatch would usually entail raising generation on a unit located somewhere in Western PJM, not in Eastern PJM. If the NYISO had established an Eastern PJM proxy bus and modeled import supply at the Eastern PJM proxy as having an impact on New York reflecting a generator being raised in Eastern PJM, this would potentially have raised the proxy price paid by the NYISO for imports that were scheduled for delivery at the Eastern proxy bus. This higher payment would not have changed the identity of the generators raised by PJM to support exports

[11] The same is true for the NYISO. The NYISO would redispatch the New York system in exactly the same way to adjust interchange with PJM, regardless of the proxy bus destination that had been designated.

and 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 PJM and backed 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. In fact, had New York set up a PJM East proxy bus, market participants could have exploited the price differentials between the Eastern and Western PJM proxy buses with schedules that would have extracted payments from New York customers without delivering any energy. Indeed, it was this kind of gaming by PJM market participants that caused the PJM ISO to move to a single proxy bus pricing system on the NYISO Interface in early 2001.[12]

Some of the inefficient scheduling incentives can be illustrated with a simple example. Suppose that the North ISO had separate East (D) and West (C) proxy buses for imports scheduled into the North ISO from locations in the South ISO but that the North and South ISOs dispatched their systems only to support the total net interchange on lines C-A and D-B. A supplier in the South ISO, observing the North ISO's $75 price at the East proxy bus would offer to sell power into the North ISO at the East Proxy bus. The impact of such a transaction, if modeled by North ISO as supported by increased generation at D, is shown in Figure 14. Compared to Figure 1, generation injections are increased 40 MW at D, decreased 13 1/3 MW at A and decreased 26 2/3 MW at B. This is the same outcome we observed above under a single proxy bus system, with the proxy bus located at D.

[12] See Andrew L. Ott, "Congestion Charges and Loop Flow."

Figure 14
Imports Supported by Generation at D

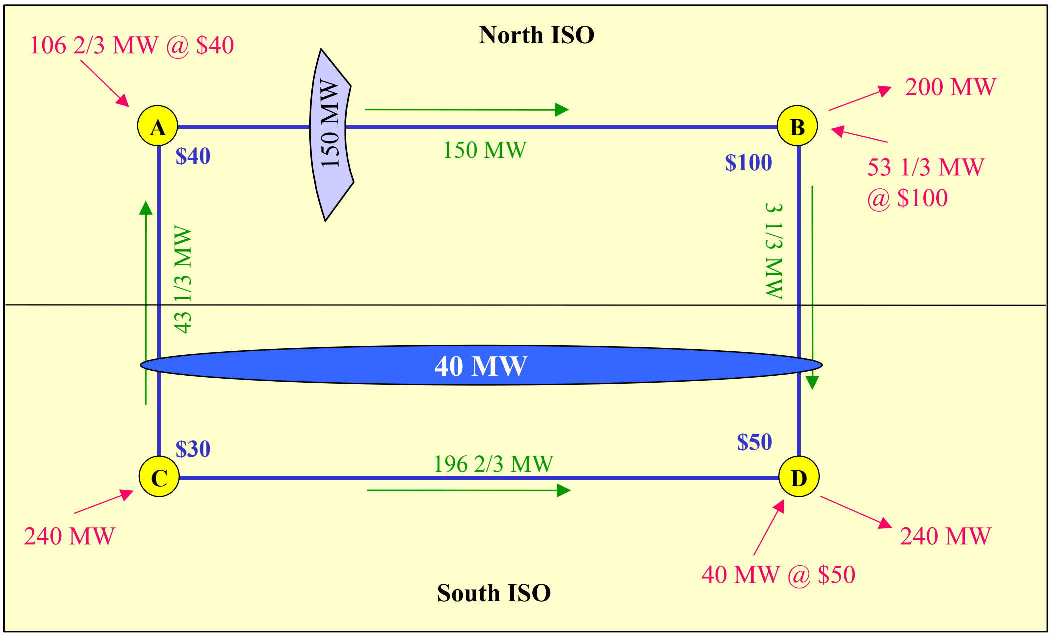


Table 15 shows that these incremental imports supported by incremental generation at D would reduce the cost of meeting load in North ISO by $1,200.

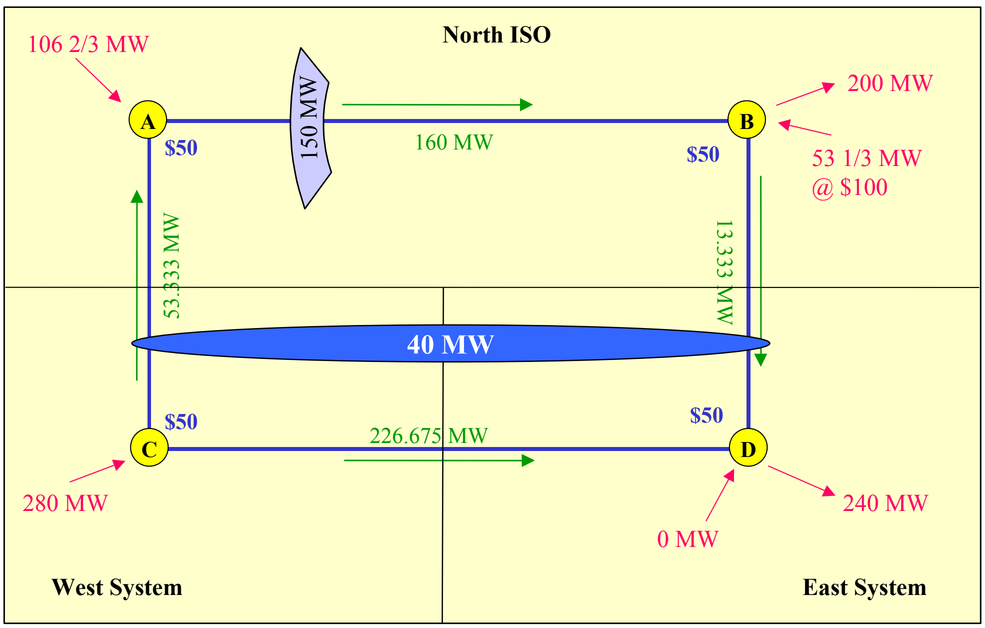
Table 15
Expected Change in Generation and Cost of Meeting North ISO Load

MWh	$/MWh	Total $
-13 1/3 MWh @ A	$40	-$533
+40 MWh @ D	$50	+$2,000
-26 2/3 MWh @ B	$100	-$2,667
Net		-1200

Figure 14 compared to Figure 1

The potential problem again arises when the supplier schedules its export with the South ISO. The South ISO would adjust its single interchange schedule with the North ISO to support an additional 40 MW of exports but South ISO would not take account of the constraint on A-B inside North ISO in dispatching its system, nor would it dispatch its system to maintain a particular level of flows on D-B. South ISO would support the increased exports to North ISO using the cheapest generation in its system. This would be $50/MWh generation at C, rather than $75 generation at D. The dispatch by the South ISO to support these exports would result in a change in net interchange of +40 into North ISO, but the flows would be as shown in Figure 16. Because the South ISO would increase generation at C rather than at D to support exports to North ISO, the impact of these exports on the North ISO in Figure 16 is different than assumed by North ISO in Figure 14.

Figure 16
South ISO Dispatch Overloads Line A-B



In particular, flows on C-A are higher in Figure 16, causing higher flows on A-B. It can be seen that if North ISO dispatches its system as portrayed in Figure 14, line A-B would be overloaded if South ISO supports exports with generation at C. As a result, North ISO would have to redispatch its system as portrayed in Figure 3, above. Once again, the North ISO would be revenue inadequate in real-time (see Table 8) because the forward schedules based on imports supported by generation at D would be infeasible when imports are, in fact, supported by generation at C.

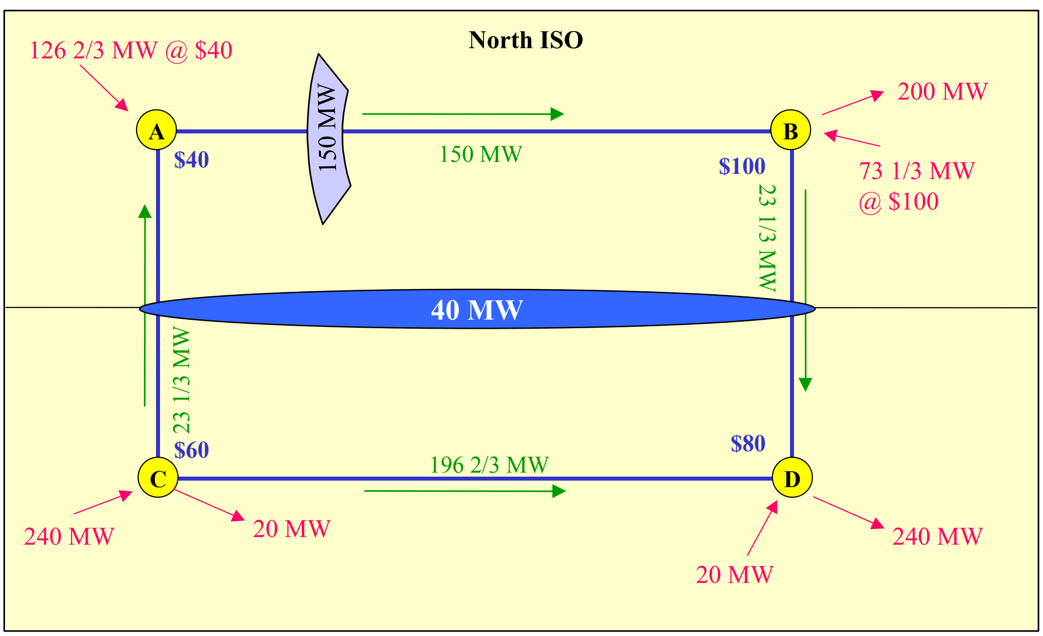
It can also be seen that the flows on the tie lines are different in Figure 16 and 14. It might, therefore, appear that tie line flows could be used to constrain the source of generation used to support exports. This is not the case. The tie line flows portrayed in Figure 16 would be produced by 40 MW of generation at C used to support exports and 240 MW of net generation at C used to support 240 MW of net load at D, and would also be produced by 40 MW of generation at D used to support exports, and 280 MW of net generation at C used to support 280 MW of net load at D. Which generation is used to meet South ISO load and which is used to support exports is purely notional.

This is the arbitrage possibility that concerned the New York ISO with multiple proxy bus pricing systems applied to free-flowing ties.[13] It is also the crux of the arbitrage that forced PJM to move to a single proxy bus for schedules with NYISO.

A further variation on this scheduling strategy would be for traders to schedule imports from D to B in North ISO, then schedule exports from North ISO at A to South ISO at C. From the standpoint of North ISO, the imported power at D would be valued at $80, while the exports to C would be valued at $60, for a net value of $20, while South ISO would value both transactions at $50, so there would be no net payments to South ISO for energy.[14]

One advantage of this kind of scheduling for the trader would be that the profitability of its arbitrage strategy would not depend on the relative level of prices in North and South ISO, but only on the relative congestion. Thus, if prices rose to $100 throughout South ISO, these schedules would still be profitable.

Figure 17
Loop Schedules



From the standpoint of North ISO, the schedules would result in the flows shown in Figure 17. This would appear to reduce the cost of meeting load in North ISO by $400 as shown in Table

13 A multiple proxy bus pricing system can be applied to schedule flows over controllable lines, as described in the DAM Study (Appendices I and II). Schedules from the New York and PJM proxy buses, however, are not linked to flows over controllable lines and the controllable lines are not always operated to maintain scheduled flows.

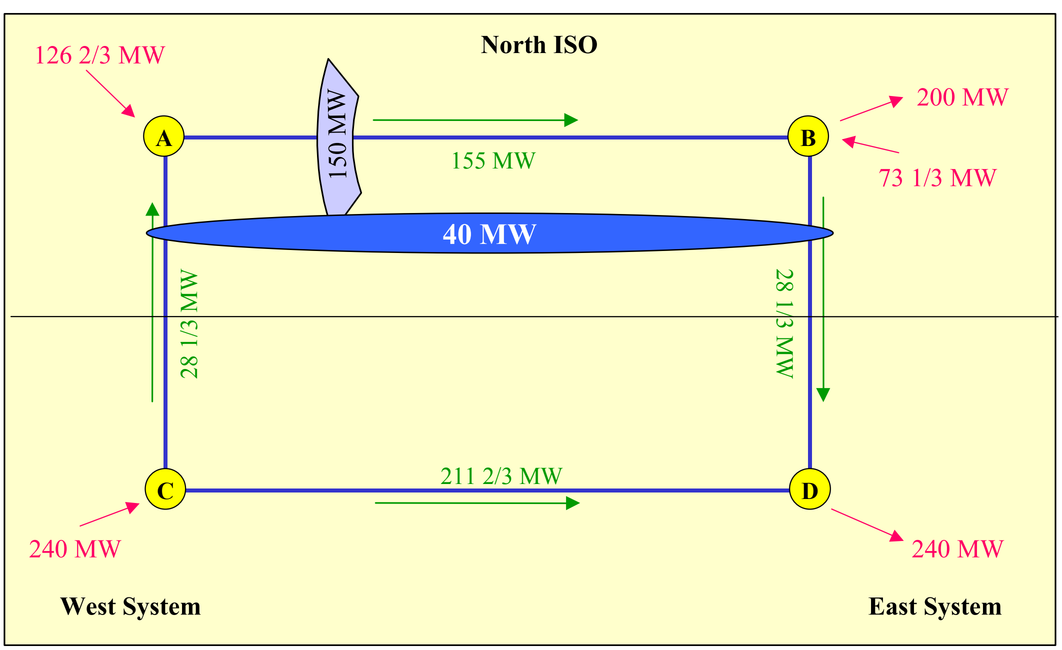
14 There would, however, potentially be export charges.

18, which would be sufficient to support payments of $400 for the scheduled imports at D less charges for exports at C.

Table 18 Loop Schedules Cost Impact		
Internal		**Costs**
-6 2/3 MW @ B	$100	-$666 2/3
+6 2/3 MW @ A	$40	+$266 2/3
Net		**-$400**
External		
+20 MW @ D	$80	-$1600
– 20 MW @ C	$60	+$1200
Net		**+$400**

In real time, however, South ISO would dispatch its system at least cost to support 20 MW of scheduled exports at D and 20 MW of imports at C, but it would not attempt to maintain any particular level of flows on lines D-B or C-A. The resulting least cost dispatch would be to generate all of the power needed to meet its load at C as portrayed in Figure 19.

Figure 19
South ISO Least Cost Dispatch



This pattern of flows would overload the A-B line, requiring that North ISO back down generation at A and dispatch up generation at B, producing the same dispatch of internal generation as in Figure 1. North ISO's cost of meeting load would have risen, however, because it would be paying an additional $400 for the scheduled net imports and exports.

The proxy bus issue indeed reflects a seams issue and it can be fully addressed for flows over open ties only by moving to a coordinated regional dispatch. Establishing a second proxy bus for scheduling a single level of tie line flows simply leads to real-time revenue inadequacy and creates gaming opportunities.[15]

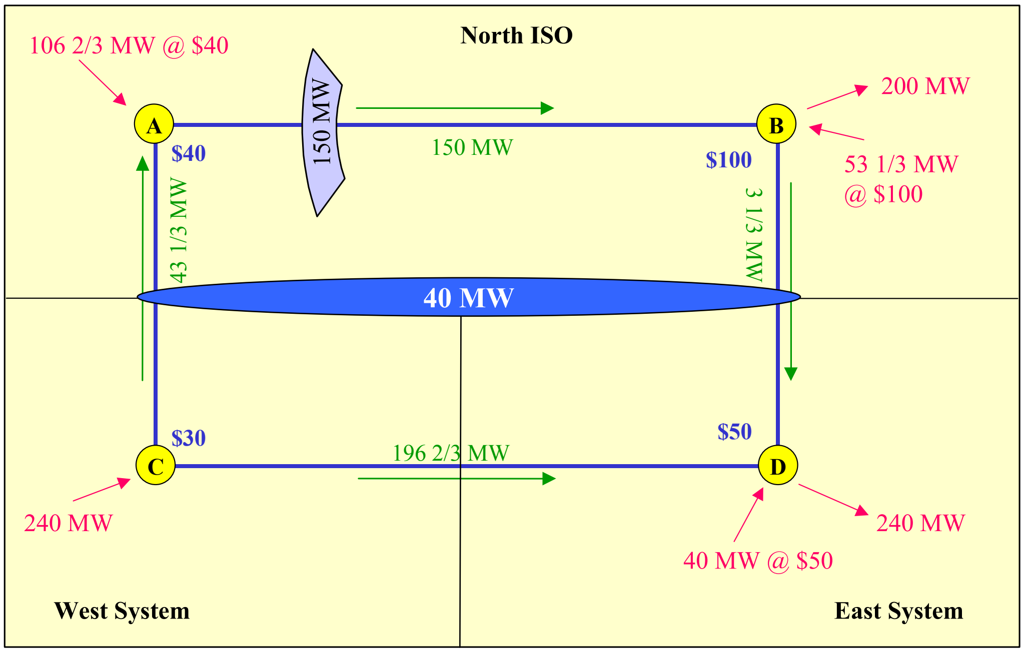
D. Multiple Control Areas

The problem of revenue inadequacy under multiple proxy bus systems ultimately arises because the multiple proxy buses effectively allow market participants to define alternative contract paths that do not reflect the actual power flows. The potential for inefficient scheduling incentives and revenue inadequacy under multi proxy bus systems is not limited to situations in which multiple proxy buses are defined within a single control area, but also arises in situations there is a single proxy bus in each control area but there are multiple adjacent control areas.

This potential is illustrated in Figure 20, in which the South Control area has been split into West and East systems, with an assumed 240 schedule for exports from West System to East System. Because West and East are separate control areas, North ISO would need to establish separate scheduling locations (i.e., proxy buses) for transactions with each control area, however, North ISO only redispatches its system to support the single combined tie line schedule. If separate prices were established for these proxy buses based on the assumption that schedules would be supported by generation at each location, the price for the Proxy bus in the East control area would be $50, while that for the West control area would be $30. 40 MW of imports offered from East control area at a price of $50 would appear economic to the North system operator, just as in Figure 14, above.

[15] As discussed at length in the DAM Study (Appendix I and II), and pp. 180-181, additional proxy buses could be established to price scheduled flows over controllable lines without giving rise to gaming opportunities and this step might be taken in the interim period prior to implementation of the Northeast RTO. This pricing mechanism would be applicable to the PAR controlled lines between New York and PJM if those PARs were operated to hold flows.

Figure 20
Multiple Control Area Scheduling



The exports from East control area to North ISO need not, however, be supported by generation located in the East control area. Those exports from East Control area to North ISO could also be supported by 40 MW of imports into the East system from West system. In this event, the actual flows would be as shown in Figure 7 above, and the A-B line in North ISO would be overloaded if North ISO dispatched its system as shown in Figure 20. This would require the North ISO to back down generation at A, and the scheduling of imports from East system would ultimately lead to revenue inadequacy and raise the cost of meeting load as shown in Table 8, because the North ISO would be required to back down low cost generation at A and meet load with high cost generation at B in real-time.

This potential for inefficient scheduling incentives with single proxy buses but multiple control areas is not hypothetical as it basically describes the situation that arose for PJM during 2002.[16] PJM found that transactions originating in ECAR or MAIN were being scheduled on a contract path basis for delivery into PJM from VACAR. 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.[17]

[16] Ott, op. cit.

[17] PJM Market Monitoring Unit, "Report to the Federal Energy Regulatory Commission, Interface Pricing Policy, August 12, 2002.

In response to this problem, PJM initially provided that transactions sourced or sunk in Main or ECAR[18] would be paid or charged the AEP proxy bus price, regardless of whether the transmission contract path ran through VACAR. In terms of the example in Figure 20 above, this would be equivalent to checking for tags on transactions coming in from East system and paying the West system Proxy bus price any time the tag showed an origin in West system. As suggested in the example, the limitation of this approach is that traders can simply break their transaction into two parts, buying in West system and selling in East system, then buying in East system and scheduling a transaction into North system. In terms of the actual change in generation, this is identical to a single transaction sourced in the West. 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.[19] As noted above, PJM moved in 2003 to a system of dynamically weighting external bus prices to determine proxy bus prices.

The NYISO is potentially exposed to the same kind of contract path scheduling for power originating in MAIN which could schedule a contract path either through the IMO or through PJM. Since generation at the PJM proxy bus has a more favorable impact on Central East than generation at Bruce in the IMO, it is likely that most entities scheduling imports into NYISO from MAIN currently choose a contract path coming in through PJM, rather than through the IMO, although the actual power flows through both IMO and PJM. This type of contract path scheduling has to date not been an issue for the NYISO. This may be in part due to the fact that both the PJM and IMO proxy buses are electrically well to the west of Central East but the differences between the PJM and IMO proxy buses are not insignificant. It may be that the main historical deterrent to contract path scheduling of MAIN generation into NYISO through PJM has been the costs of scheduling contract path transmission from MAIN into NY under pancaked tariffs in the Midwest. It may therefore be the case that as pancaking diminishes in the Midwest as the MISO moves to LMP, the NYISO may see an increase in generation schedules that have contract paths through PJM, but if accepted by NYISO, will actually cause incremental generation to be dispatched in MAIN or even MAPP. This could require 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 in accord with actual flows. The expected Fall 2003 commissioning and proposed operation of PARs controlling the IMO to Michigan actual power flows to the level of scheduled transactions would mitigate the exposure of the NYISO to the multiple adjacent control area proxy bus issue.

The multiple proxy bus problem is also related to the Enron scheduling strategy in California that was referred to as Deathstar. Suppose that an entity scheduled an import from East system into North ISO, then scheduled a counterflow transaction from B to A within North system, and then an export from A to C. The importer would pay \$15/MWh for congestion from D to B, be paid \$60/MWh for relieving congestion from B to A and pay \$30/MWh for congestion from A to C.

[18] The source or sink would be determined from the NERC tags.

[19] PJM Market Monitoring Unit, "Report, Interface Pricing Policy, February 28, 2003. PJM, PJM Interface Pricing Changes.

Overall, the entity would pay $45/MWh and receive $60/MWh for a net profit of $15/MWh. If the entity could buy transmission service from C to D for $15/MWh or less, it would be able to earn a profit on a purely financial schedule. The potential inefficiency was magnified in California because the CAISO used a contract path rather than proxy bus scheduling system.

E. Other Issues

The discussion and examples above have focused on the revenue inadequacy issues that can arise under multiple proxy bus and multiple control area scheduling systems. Another potential impact of multiple proxy bus systems could be reduced utilization of the transmission grid. This outcome would arise if the system operator defined separate scheduling limits for each proxy bus. This was the policy of the California ISO, which defined separate contract path scheduling limits for numerous external proxy buses. This approach required that market participants individually fully schedule each proxy bus in order to fully utilize the available system transfer capability.

Since market participants could not anticipate the scheduling actions of others, this scheduling system created the both the potential for and likelihood of differences in congestion, creating arbitrage opportunities for entities like Enron, but reducing the overall efficiency of the market and giving rise to the likelihood that some scheduling paths would not be fully utilized at the same time that other paths had substantial congestion. This is not an inevitable feature of a multiple proxy bus system. A more rational approach than that adopted by the California ISO would be for the system operator to define an aggregate interface constraint and model the impact of schedules across each interface on this constraint, thus ensuring that all transactions are accepted until a constraint is actually binding

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.