DRAFT

Virtual Regional Dispatch Straw Proposal

Draft for Comment

1. Foreword

This straw proposal is a work in progress. The issues are complex, with several feasible alternative approaches. This proposal presents an initial complete proposal drafted by the ISOs. The Virtual Regional Dispatch white paper issued on May 19 2003 provides a description of alternative implementation approaches. It is available on the ISO-NE website at the following link:

http://www.iso-ne.com/committees/markets/2003_05_29/

It is also available as a link on the New York ISO's home page:

http://www.nyiso.com/ Virtual Regional Dispatch Joint Working Paper.

2. Introduction and Summary

The virtual regional dispatch proposal was developed to meet two key objectives. First, it will eliminate many of the seams that currently impede the ability of Market Participants with load in one area to serve that load from generation in the other control area. Second, coordinating the dispatch of the New York and New England Control Areas will increase the efficiency of dispatch over both control areas, thereby reducing the overall cost of serving load in the regions.

In addition to improving regional efficiency, under VRD each ISO should experience an overall reduction in the cost of serving load. Normal day-to-day efficiency improvements are expected to lead to lower costs. Perhaps more importantly, VRD will facilitate the expeditious importation of lower priced energy during periods of tight supply due to unanticipated high load or outage conditions.

The essential elements of the proposal are summarized below:

- The amount of flow between the two control areas will be determined by the ISOs in the following manner:
  - The ISOs' scheduling objective is to converge prices at the respective proxy buses.
  - The ISOs will review and adjust the physical interchange every 15 minutes to maintain price convergence.
  - The ISOs will share explicit pricing curves representing sensitivity to interchange schedule changes, for the purpose of establishing efficient interchange.
- VRD will not affect settlements for day-ahead transactions.
- Settlements for real-time transactions under VRD will change as described below:

- The types of transactions currently enterable into the real-time markets remain unchanged.
- The deadline for submitting real-time transactions will be extended to noon of the day following the scheduling period.
- VRD will not change the settlement and responsibilities for payment of fees related to Transactions scheduled day-ahead that also are scheduled to flow in real-time.
- For transactions scheduled to flow in real-time that were not scheduled in the day-ahead market, the responsibility for paying transmission fees, ancillary services, operating reserve, etc. and is replaced by a transaction charge equal to the difference in proxy bus prices
- The decision as to which price sensitive transactions flow will be made after the fact using actual real time prices Consequently, price quarantees will no longer be need for transaction scheduled over the virtual interface.
- The VRD schedule will be set to the difference between the physical real-time schedule and the net participant schedules.
- The formula for distributing the residual funds beyond export fees, collected through transaction charges and virtual scheduling, will be developed in cooperation with stakeholders. Congestion will be compensated from the residual fund.

The Virtual Regional Dispatch (VRD) Straw Proposal eliminates many of the seams issues between New York and New England, by enabling the ISOs to make joint dispatch decisions that will facilitate price convergence at the border. It will allow the adjacent control areas to realize many of the benefits of a larger market, while minimizing the technical, legal and political implementation barriers. All current system reliability and security rules and processes will remain in force, so that the economic and secure dispatch of the individual control areas will not be compromised. Each ISO will continue to evaluate the bids and offers in its own market separately, and together the ISOs will adjust the energy flow over the interface to cause real-time prices to converge.   While not producing as efficient a real-time dispatch as would a single regional dispatch, the VRD process is expected to yield substantial efficiency gains over current procedures.

Under this proposal, the current rules that require Market Participants to submit contracts between the control areas at least an hour ahead of time will be eliminated. Participants will be able to submit such transactions until the start of the hour in which the transaction is scheduled to flow.[1] These changes are made possible because Participant transactions between the ISOs will become financial, similar to today's bilateral transactions within each market, rather than physical as they are today.   As part of the proposal, the ISOs will dispatch the physical flow between markets in much the same was as they dispatch flows within each market.

This proposal includes provisions for the ISOs to schedule physical flows over the NYISO-ISO-NE interface, in order to bring about price convergence at their respective proxy busses. Participant-scheduled transactions will flow, independent of the physical flow between control areas, just as internal bilateral transactions flow. This proposal calls for initially evaluating the physical interchange schedule every 15 minutes. Projected price differentials between the markets at their designated proxy locations will cause the ISOs to adjust the net interchange to equalize prices at the border.

[1] In fact, the possibility of submitting such transactions after the fact is included as a part of the proposal.

The proposed settlement procedures for Participant transactions between regions build upon the current systems. The pricing and settlement of Market Participants' real-time transactions under VRD will be very similar to the way in which both markets treat internal transactions today. The settlement rules will enable load in the importing area to purchase power from generation in the exporting area.

This proposal does not entail any changes to the existing day-ahead market software. ISO-NE and NYISO will continue to run completely separate day-ahead markets that support their Market Participants' ability to schedule fixed and price sensitive transactions between the two control areas. Rather, the stabilizing effect of improved real-time price convergence between the adjoining areas should be reflected in the day-ahead markets of both New York and New England. Thus, Market Participants in the day-ahead market will also benefit from VRD, without specific changes to the design of the day-ahead markets.

The remainder of this document provides details of the changes to system operation, bidding, and settlement envisioned by the ISOs initial approach to Virtual Regional Dispatch. Examples of settlements under different conditions are contained in Appendix I.

3. Physical Scheduling of the Interchange

It is anticipated that the actual interchange between New England and New York will be determined jointly by ISO-NE and the NYISO, without consideration of the intra-day, price-sensitive or reserved, cross-border, bilateral transactions submitted by Market Participants. Tools in each control area that estimate the near-term sensitivity of price to changes in interchange will be used to calculate the flow level required to equalize the proxy prices in the adjoining markets. This section discusses the process for physically scheduling interface between New England and New York.

Salient features of the ISOs' proposed physical scheduling process include the following attributes:

- The schedule will be adjusted every 15 minutes.
- The physical limits of the NYISO/NEPOOL interface will not be exceeded.
- Neither control area will dispatch its required reserves in order to support export schedules. Hence, at times the full capability of the interface may not be used, even if transfer capacity remains available.
- There will be a limit on the adjustment of energy flows from one 15-minute period to the next 15-minute period.
- Consent of the two control areas will be required for any schedule change.
- Each schedule change will be finalized 15 minutes before flowing (10 minutes before the ramp begins).
- The ramp from one scheduled flow to the next will be done over a 10-minute period beginning five minutes before the start of the schedule period, and ending five minutes after the start of the schedule period.

- Each control area will periodically provide the other with its estimate of how it expects changes in scheduled interchange to affect prices at the proxy bus.

A discussion of the expected real-time dispatch processes in each market follows. It is assumed that ISO-NE will continue to update its market with planned changes and software development, and that the NYISO will have made the transition to the RTS software design that is part of its SMD2 project, prior to any VRD deployment.

The real-time processes of both IS-ONE and NYISO will be providing for the intra-day commitment of quick-start generating units:

1. The ISO-NE unit commitment evaluation will continue to be integral to its dispatch function. The dispatch process allows commitment of generators with a startup time as long as 15 minutes. The need for additional generation is evaluated every five minutes by calculating conditions for a single time period 15 minutes in the future.

2. The NYISO RTS process will commit generators with a startup time of 30 minutes or less. The commitment process in New York will be independent of the dispatch process; will be evaluated every 15 minutes; and will optimize over ten time periods that extend three hours into the future. When the need arises, each control area can manually commit non-quick start generating units, a process that includes the use of manually initiated evaluation software.

The ISOs' security-constrained dispatch algorithms will operate as follows:

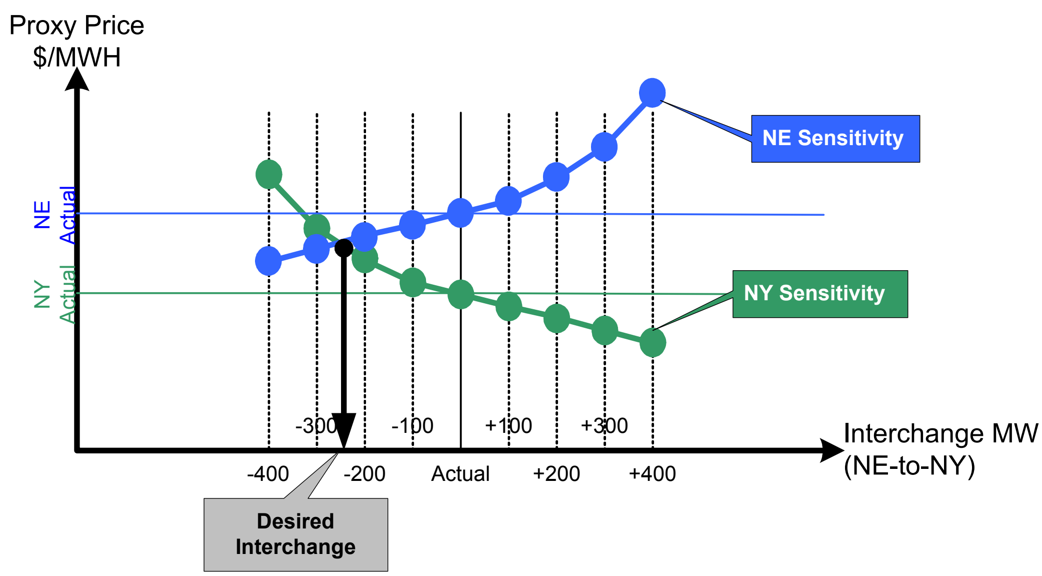
1. ISO-NE's security-constrained dispatch will continue to calculate prices and desired schedules every five minutes, for 15 minutes into the future. A supplementary look-ahead process will perform a dispatch one hour into the future. The look-ahead function will run less frequently than the dispatch. Import, export and wheel through transactions will be considered as fixed injections and withdrawals by the ISO-NE dispatch function.

2. The NYISO security-constrained dispatch function (RTD) will be a multi-period security-constrained dispatch model that co-optimizes to solve load, reserves and regulation simultaneously. Each RTD run will optimize over a period of one hour. RTD will make no unit commitment decisions. It will simply dispatch the resources available to it on a least as-bid cost basis. RTD will run every five minutes. Import, export and wheel through transactions will be considered as fixed injections and withdrawals by RTD.

Under VRD, both New York and New England will periodically estimate price at their proxy for the other control area for various interchange flows. The Native load forecast and the flow over other external interfaces will most likely be fixed during these "what-if" dispatch simulations. Within each market, the projected price at the neighboring VRD proxy bus for each of the selected flow levels will be determined by the re-dispatch of internal generation to meet forecast load. The control areas would exchange this information, utilizing it to determine a common desired interchange level.

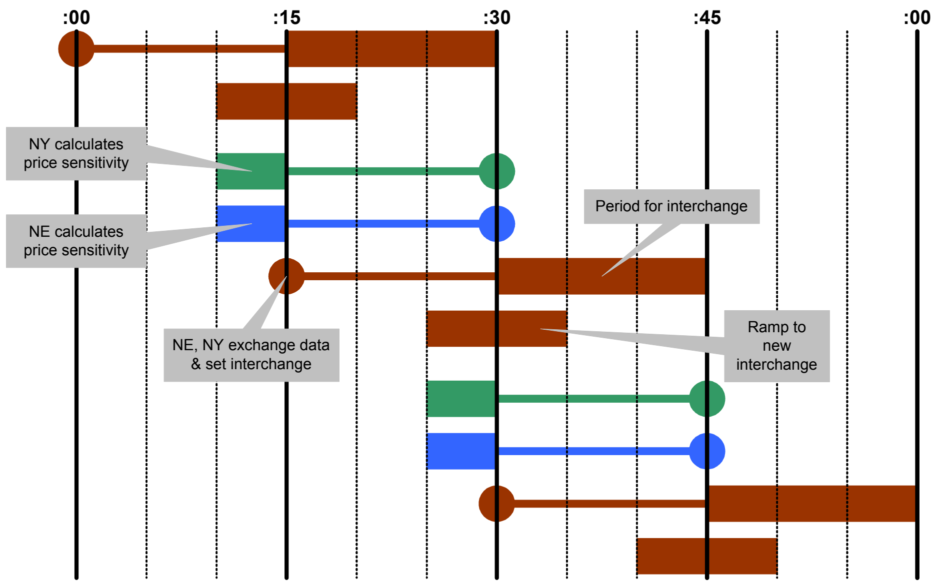
As shown in Figure 1, the desired interchange can be found by analyzing the estimated prices and schedules. The methodology estimates particular points on the curves, from which piecewise linear curves can be developed. This technique will not produce an exact representation of the actual supply curve for either market, but the desired interchange can either be interpolated, or a rule to use the next higher or lower level of scheduled interchange will be implemented. With this "flow model," the control areas will agree upon the level of flow to schedule. In real-time, generation will be dispatched to meet actual load, given scheduled net interchange and proxy bus prices calculated from this dispatch. The VRD process should cause proxy prices to converge, although they will not necessarily become equal. While not shown in Figure 1, export fees will be included via a price bias equal to the fees of the exporting market.

Figure 1: Flow Model



Given the use of the flow modeling technique described above, the process carried out between the ISOs for determining that interchange is illustrated in Figure 2. The process will repeat itself every 15 minutes. By 15 minutes before the period being scheduled, each market will have performed the following steps: 1) estimated the price at the neighboring VRD proxy bus for each of the selected interchange levels; 2) exchanged the data with the other control area; and 3) agreed to the net scheduled interchange. These activities will begin approximately 20 minutes before the period being scheduled, and will yield a new schedule within five minutes. Five minutes before the scheduling period, the ramp to the new schedule will begin.

Figure 2: VRD Process



Forward modeling is also under consideration. It entails estimating the expected flows farther in the future and would take advantage of the ISO-NE look-ahead feature and the NYISO's intra-day optimizations over multiple time intervals. Forward models of expected interchange for future intervals may prove beneficial in improving scheduling of other non-VRD functions, such as interchange schedules at non-VRD interfaces.

4. Bidding Opportunities

As described in the previous discussion on physical scheduling, the most significant change associated with bidding transactions into the ISOs is that the bids will not directly determine the physical flow to be scheduled between the markets. They will, instead, determine how much of the actual energy flow in real-time consists of Market Participants' transactions, and how much additional energy the ISOs' will exchange between markets to improve the efficiency of the regional dispatch. The bidding mechanics will change little. The exception is that e-schedule capability will be added to the real-time external transaction scheduling process. With this capability, NYISO will be adding e-schedules to the real-time internal bilateral scheduling process as well. The capability will be consistent with the current ISO-NE procedure allowing Market Participants to submit bilateral transaction schedules up to noon of the following the operating day. Note that the timing requirements for submitting schedules for wheel-through transactions will not change, as they will involve at least one market that is not participating in VRD.

4.1. Day-Ahead Market Bidding

Since VRD will be a real-time dispatch process, the DAM bidding mechanics, upload and download software will remain essentially unchanged. One issue remaining to be developed is a means of uniquely identifying both ends of an inter-market transaction in the two markets for settlement purposes. Other than that, no changes are expected in the bidding form (therefore no other DAM upload or download software changes would be required for VRD) and closing and posting times will continue to follow current market practices.

4.2. Real-Time Bidding

As VRD will represent real-time dispatch coordination between markets, it naturally will have some impact on the real-time bidding process. The most significant change will involve relaxing real-time submittal deadlines for Market Participant transactions. Highlights of the proposed changes to the real-time bidding process follow:

- Bidding intervals will initially be hourly, moving to 15-minutes once both markets have completed other priority projects. Final quarter-hour scheduling rules will be promulgated, and associated software changes undertaken and tested at that time.
- VRD will continue to support bidding of both bilateral transactions and cross border, price sensitive sales and purchases.
- Market Participants will be able to submit or modify real-time inter-market transactions (except for wheel-through transactions) until noon of the day following the operating day, as is currently the case in the ISO-NE internal market.
- Inter-market transactions will not be used to determine the scheduled hourly flow as they are today, nor will they set real-time proxy prices as they do today in New York when transmission or ramp congestion is present. Instead, they will be evaluated after the VRD dispatch, and all economic transactions will be assumed to have flowed for purposes of settlement.

4.3. Day-Ahead and Real-Time Transactions

ISO-NE and NYISO differ in the way they treat transactions scheduled in the day-ahead market. Either of these approaches would work in the VRD environment, and it is possible to configure the process around the current practices. The ISOs propose to solidify this part of the design in collaboration with Market Participants going forward.

- In New York, a transaction scheduled in the day-ahead market defaults to economic priority for real-time (the market assumes that the Participant desires the contract to flow iin real time). While they have a financial obligation if the transaction fails to flow, Market Participants are free to reset the parameters of the transaction to any level they choose. They can choose not to flow the day-ahead contract, but must make a MW change in order to do so.
- In New England today, the day-ahead-to-real-time process for scheduling transactions is the opposite of New York. All day-ahead transactions are considered as virtual (financial entities only), and Market Participants must specifically request that a transaction scheduled day-ahead (with a financial obligation) actually be scheduled by ISO-NE to flow in real-time.

4.4. Market-Specific Bidding Process Changes Associated with VRD

- ISO-NE – Possible liberalization of submission time constraints on real-time price sensitive bidding to be consistent with NY.

- NYISO – Real-time market closing times will change. e-schedules for internal and inter-market transactions will be added. The NYISO will institute the e-schedules treatment for inter-market transactions with participating VRD markets and for all internal bilateral transactions as part of the VRD implementation.
- Both markets will adopt some mechanism to identify a unique transaction in both markets and permit inter-market transactions to be tracked and settled properly in both markets.
- It may be necessary for day-ahead Transactions entered into the New England market to add a transaction identifier such as the tag currently entered in the New York day-ahead market. Tagging may need to be replaced by an alternate type of identification, since NERC tagging does not allow for late entry, and the ISOs need to accommodate tagging up to noon of the following day.

5. Market Design Changes

5.1. Settlement Rules

The pricing and settlement rules under VRD will be relatively straightforward. First, the day-ahead market processes will be largely unchanged. Transactions scheduled day-ahead in the NYISO and ISO-NE day-ahead market processes and scheduled to flow in real-time will not pay any real-time inter-ISO transaction charges, unless is flows in real-time. Market Participants scheduling these day-ahead transactions will be responsible for payment of any export fees that remain in place under VRD for the portion of these day-ahead schedules that flow in real-time. Second, market participants scheduling inter-ISO transactions to flow in real-time will pay a transaction charge that reflects both congestion charges and export fees.{DL: Day-ahead pricing explanation is not clear – comes out of nowhere.} This charge will be equal to the difference between the LMP in the importing ISO's real-time market at its proxy bus for the exporting ISO, and the LMP in the exporting ISO's real-time market at its proxy bus price for the importing ISO. Since this charge will cover both congestion charges and export fees, no additional payments by Market Participants would be necessary for these real-time transactions. This section proposes rules for pricing and settlements for transactions scheduled in the real-time and the day-ahead markets.

5.2. Real-Time Schedules

5.2.1. Market Participant Transactions

Upon implementation of VRD, Market Participants will continue to be able to schedule transactions between ISOs that settle at real-time prices. The current requirement that transactions between the control areas must be submitted at least 75 minutes (NY) or 60 minutes (NE) ahead of the hour will be eliminated. External transactions settling at real-time prices will be accepted for scheduling until noon of the day-after the transaction is scheduled to have flowed. } Market Participants scheduling such transactions will pay the difference between the exporting region's proxy bus price for the importing region and the importing region's proxy bus price or the exporting region for such inter-ISO transactions.[2] Virtual regional dispatch would be implemented in a manner to facilitate the collection of export-related transactions fees.[3] This aspect of VRD will be accomplished by limiting real-time price convergence to no more than the difference corresponding to the estimated export fees. This method would enable the export fees to be paid from a transaction charge equal to the difference in prices between the importing and exporting control area.

Thus, market participants scheduling an inter-ISO transaction into New York from ISO-NE in real-time would pay a real-time inter-ISO scheduling charge amounting to the difference between the NYISO real-time proxy bus price for ISO-NE and the ISO-NE real-time proxy bus price for New York.. This inter-ISO schedule would create a load obligation in ISO-NE at the NYISO proxy bus, and an offsetting load credit in NYISO at the ISO-NE proxy bus price. Similarly, Market Participants scheduling an inter-ISO transaction into New England from New York in real-time would pay the difference between the ISO-NE real-time proxy bus price for New York and the NYISO real-time proxy bus price for ISO-NE. This inter-ISO schedule would create a load obligation in New York at the ISO-NE proxy bus and an offsetting load credit in ISO-NE at the NYISO proxy bus price.

Example 1

Suppose, for example, that BlueCo schedules a 50 MW injection at Niagara and an export from the NYISO to ISO-NE for hour beginning14. Figure 3 portrays the hypothetical real-time prices in NYISO and ISO-NE for hour beginning 14. It is also assumed that the New York export fees are $7/MWh. BlueCo would pay the difference between ISO-NE's NYISO real-time proxy bus price (NE Proxy) and NYISO's real-time ISO-NE proxy bus price (NY Proxy) ($59-$49=$10/MWh) into the settlements system of the exporting control area (New York in this example) to schedule the inter-ISO transaction.[4] The settlement system of the exporting control area would distribute these revenues to the appropriate accounts. Thus, $7/MWh of the real-time transaction scheduling charge would be credited to the appropriate accounts for export charges. The remaining $3/MWh is a VRD residual, and will be distributed as described below. In New York, the 50 MWh schedule would be accounted for as a real-time withdrawal and offset against the value of the actual real-time injections at Niagara, with any differences between the 50 MWh injection schedule and the actual real-time generation settled at the $49 real-time price.[5] In New England, BlueCo would be credited for a 50 MWh import schedule as a real-time injection that would cover 50 MWh of its real-time Boston load.[6] BlueCo would settle any deviations between its actual load and the 50 MWh import schedule at the real-time LMP price in Boston, $59/MWh.

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[2] If market participant inter-ISO transactions continue to be scheduled on an hourly basis, these settlements could continue to be calculated on an hourly basis, based on the difference in average hourly real-time prices. If market participants are permitted to schedule changes in inter-ISO transactions on a sub hourly basis, then the settlement prices will need to be computed on a similar basis, i.e. 15 minute basis for 15 minute schedules or 5 minute basis for 5 minute schedules.

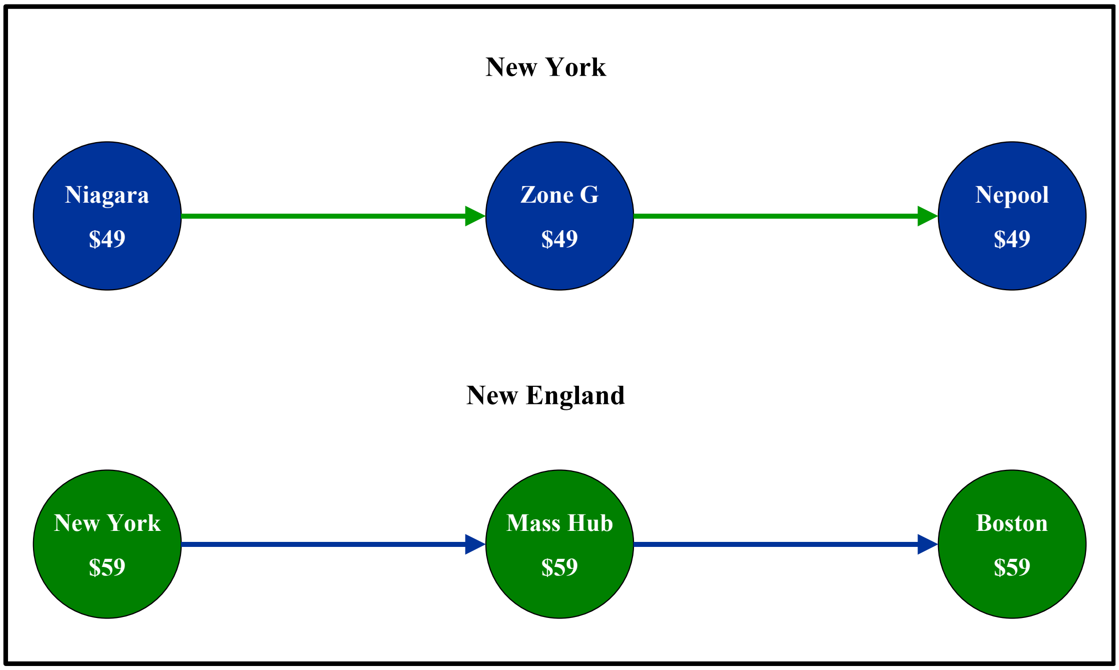
[3] These export fees include any transmission access charges, schedule 1 charges, and ancillary services charges (operating reserve and regulation). As these changes are implemented, the ISO will remove limits on price convergence, and attempt to bring prices as close as possible.

[4] It needs to be resolved whether it would be preferable to pay this charge to the ISO for the exporting region or to the ISO for the importing region.

[5] In practice, BlueCo would pay for congestion and losses between Niagara and the NYISO NEPOOL proxy bus, but we have assumed there are neither congestion or losses in this example.

[6] Once again, BlueCo would in practice pay for congestion and losses between ISO-NE New York proxy bus and Boston, but we have assumed that there are neither congestion nor losses in this example.

Figure 3: Real-Time Prices, Hour 14



Real-time inter-ISO transactions would become financial, like real-time internal transactions, and the cost of the power would not depend on whether a Market Participant scheduled real-time inter-ISO transactions, or bought and sold power in the real-time spot markets. For example, suppose that BlueCo had purchased power from the NYISO real-time spot market to support its real-time export schedule. Instead of scheduling an injection at Niagara, it would have bought power from the NYISO at the ISO-NE proxy bus price ($49), paying the difference in proxy bus prices ($59-$49=$10) to schedule the inter-ISO transaction from New York to ISO-NE. The net cost for power delivered to ISO-NE load would be $59/MWh, the same as if the Market Participant bought power in the ISO-NE spot market.

5.2.2. Settlement of Physical Flows Scheduled by the ISOs

In addition to Market Participant inter-ISO transactions, there would also be real-time inter-ISO energy flows scheduled by the ISOs, which we will refer to as VRD schedules. They would be the difference between the net scheduled physical flow and net Market Participant inter-ISO schedules, and would be priced and settled on the same basis as Market Participant inter-ISO transactions. The difference in prices would result in net charges that would be accumulated in a VRD account. Thus, the importing ISO would pay its proxy bus price for the exporting region into a VRD account for the power it brings into the region during each dispatch interval. The exporting ISO would be paid its proxy bus price for the importing region from the VRD account for the power it exports during each dispatch interval.

Example 2

Suppose, for example, that ISO-New England and NYISO schedule 50 MW of VRD transactions during dispatch interval 14:00 to 15:00, {DL-use hourly -- roll-up issues are details} with the real-time prices portrayed in Figure 3. ISO-NE would pay $59/MWh (the ISO-NE New York proxy bus price) to the VRD settlement account for power delivered from New York by the VRD schedule during this dispatch interval. Similarly, NYISO settlements would be paid $49/MWh (the NYISO ISO-NE proxy bus price) from the VRD settlement account for the power delivered to ISO-NE through the VRD schedule during this dispatch interval. The remaining $10/MWh is termed the VRD residual, and its treatment is described below.

5.3. VRD Residual

The proposed real-time settlement rules will give rise to a VRD residual whenever the settlement prices in the importing and exporting regions diverge. This residual will have three components. First, until and unless all export fees (including ancillary service fees assigned to exports) are eliminated, a portion of the VRD residual will be attributable to and used to pay these export fees. That is, until export fees are eliminated, perfect price convergence will entail ISO settlement prices that differ by the per MW amount of estimated export fees. This component of the VRD residual account will be tracked, and the revenues transferred from the VRD residual account to the appropriate accounts of the exporting ISO. Second, the VRD residual will include congestion rents when the price difference exceeds export charges, because net real-time inter-ISO scheduled physical flows exceed day-ahead schedules, and real-time scheduled physical inter-ISO flows are limited by transmission constraints. (The disposition of these congestion rents/price differences has not been determined.[7]) Third, the VRD residual will also include a component arising from imperfect real-time inter-ISO price convergence. That is, there will be times that the difference between the real-time prices is not equal to export charges, yet there is no transmission congestion between the regions.

Overall, the proposed pricing and settlement rules have the potential to give rise to a VRD residual deficit if the real-time scheduled physical inter-ISO flows are uneconomic at real-time prices. Significantly, under the proposed settlement rules, the magnitude of the potential VRD residual deficit depends on the level of uneconomic scheduled physical inter-ISO flows, not on the level of real-time inter-ISO financial schedules. The settlement rules thereby avoid engendering incentives for Market Participants to structure profitable but inefficient transactions that exacerbate revenue inadequacy. However, the pricing rules do not eliminate the potential for revenue inadequacy in VRD settlements arising from uneconomic scheduled physical flows.

The operation of the proposed settlement rules can also be illustrated for the simple example portrayed in Figure 3. First, suppose that the scheduled physical flow from NYISO to ISO-NE was 250 MW, 100 MW of which reflects Market Participant transactions. The Market Participants would pay the difference between the IS0-NE price for New York ($59/MWh) and the New York ISO-NE price ($49), or $10/MWh for their 100 MW of transactions. In addition, the 150 MW of VRD schedules would result in the purchase of 150 MW from NYISO at NYISO's ISO-NE proxy bus price, and the sale of 150 MW to ISO-NE at the ISO-NE New York proxy bus price. Thus, as shown in Appendix I, the real-time schedules would generate $2,500 in VRD residuals. Of this amount, $1,750 would be utilized to settle the export fees of $7/MWh, while the remaining $750 would be a VRD residual surplus.

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7 One proposal is to credit this residual to the exporting region, potentially providing a partial offset to any price impact of real-time imports.

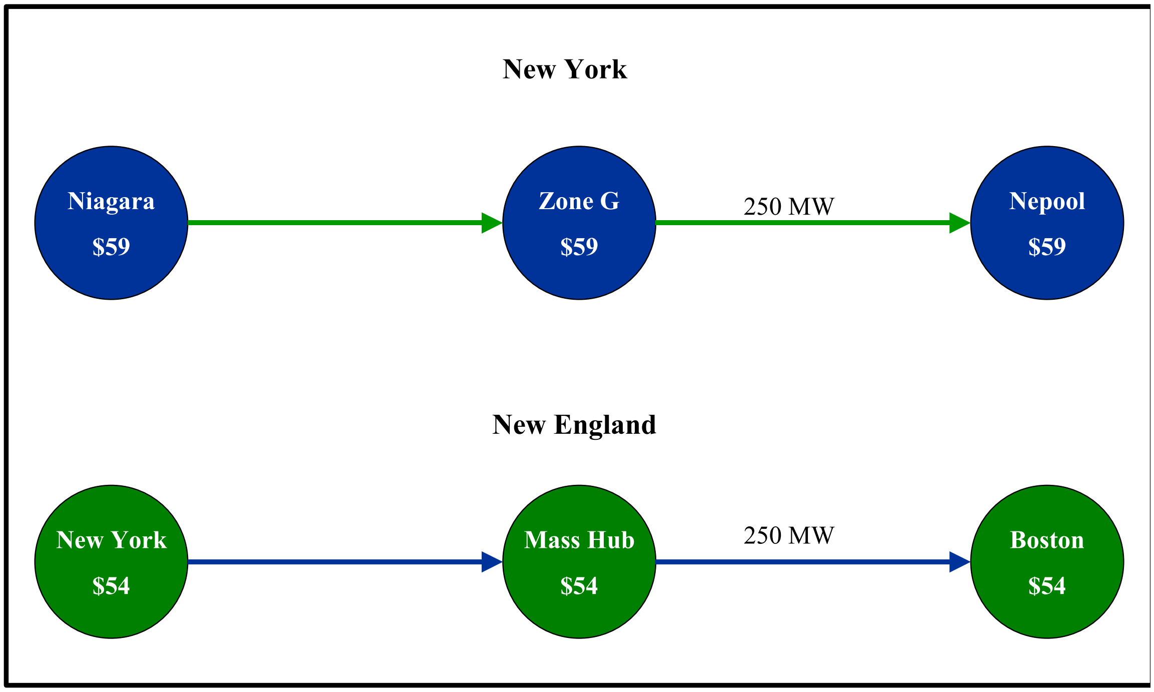
It is noteworthy that although additional scheduled physical interchange would be efficient in this example, no incremental profit accrues to Market Participants from scheduling additional financial transactions. The inter-ISO transaction scheduling charge would be $10/MWh, which is exactly equal to the difference in real-time proxy bus prices. Thus, if BlueCo bought power from the NYISO real-time market to support exports to ISO-NE, BlueCo would break exactly even. BlueCo would pay $49/MWh to buy power in the NYISO spot market and $10/MWh for scheduling the real-time inter-ISO transaction from NYISO to ISO-NE. BlueCo could sell the power in the ISO-NE real-time spot market for $59/MWh. This result is important, because it means that even if Market Participants scheduled 2,500 MW of real-time transactions from NYISO into ISO-NE, resulting in 2,250MW of real-time VRD schedules from ISO-NE to NYISO, the VRD account would generate the same $2,500 as if there were only 100 MW of Market Participant transactions.[8] This effect is illustrated in Appendix II. The additional 2,250MW of financial inter-ISO schedules from NYISO into ISO-NE would pay $10/MWh for each MW scheduled, while the offsetting 2,250 of additional inter-ISO VRD schedules would be paid $10/MWh for each MW of VRD schedule. The inter-ISO transaction scheduling charges for the Market Participant transactions and VRD schedules would be offsetting, and the VRD schedules would be revenue neutral, without regard to the level of real-time prices.

Example 3

A third example is based on the real-time prices portrayed in Figure 4. It is again assumed that the scheduled physical flow from NYISO to ISO-NE is 250 MW, 100 MW of which reflects Market Participant transactions, but in Figure 4 these transactions are flowing from the high-priced region to a low-priced region. While it is intended to use the VRD process to adjust inter-ISO flows to avoid this outcome, the settlement rules need to account for this situation, which will likely arise from time to time. Under the proposed settlement rules, the inter-ISO transaction scheduling charge would be -$5/MWh; that is, Market Participants scheduling transactions from NYISO to ISO-NE would be paid $5/MWh for scheduling the inter-ISO transaction. Importantly, the scheduling of such transactions would still be profit neutral for the Market Participant as they would buy power from NYISO at $59/MWh, receive a $5/MWh inter-ISO transaction scheduling credit, and then sell the power in ISO-NE at the ISO-NE NY proxy bus price for $54/MWh, just equaling the cost of the power.

8 These settlements are portrayed in Appendix II.

Figure 4: Real-Time Prices, Hour 14



In aggregate, however, the VRD residual account balance would be -$1,250, as illustrated in Appendix III, and the account would also need to cover export charges of $1750 ($7 times the 250MW scheduled physical flow). This deficit arises from the inefficient flows in relation to real-time prices. Importantly, this deficit is also unaffected by the scheduling of additional inter-ISO financial transactions. Thus, if Market Participants scheduled 2,500MW of financial transactions from NYISO to ISO-NE, as shown in Appendix IV, the VRD residual account shortfall would still be -$1,250. The additional 2,400MW of financial transactions from NYISO to ISO-NE would be offset by an additional 2,400MW of VRD schedules from ISO-NE to NYISO. The 2,400MW of VRD schedules would pay an additional $5/MWh in inter-ISO transaction scheduling charges, which would exactly generate the additional $12,000 to be paid on the Market Participant transactions. Moreover, the ISO-NE to New York VRD schedules themselves would be profit neutral for the VRD settlements, as power would be bought at $54/MWh, and sold at $59/MWh, with payment of a $5/MWh Inter-ISO transaction scheduling charge.

5.4. Day-Ahead Schedules

Following implementation of VRD, the NYISO day-ahead market would continue to operate as it does today.Market Participants would submit offers to buy and sell power at the ISO-NE proxy bus and schedule import and export transactions, and the NYISO would continue to enforce transfer limits between New York and ISO-NE in its day-ahead schedules. Similarly, it is assumed that the ISO-NE day-ahead market and real-time scheduling process would also continue to operate as it does today. In particular, it is assumed that transactions between

NYISO and ISO-NE that are scheduled in the NYISO DAM would continue to have time stamp scheduling preference in the ISO-NE real-time scheduling process in the event that there are excess imports offered at the minimum price, or excess export bids at the maximum price.[9]

The settlement rules described above would govern the settlements for transactions scheduled in real-time. While the proposed VRD would initially only determine the level of real-time inter-ISO flows, the settlements will need to account for transactions scheduled in day-ahead markets, as well as in real-time, in order to ensure revenue adequacy for the settlement systems of both ISOs and avoid inefficient scheduling incentives. In particular, while VRD will not alter the structure of the day-ahead markets themselves, VRD will fundamentally change the nature of the hour-ahead check-out process, which establishes which day-ahead transactions flow in real-time. The scheduled level of real-time physical inter-ISO flows will be determined by NYISO and ISO-NE through the VRD check out process, without regard to market participant transaction schedules. The scheduled level of market participant inter-ISO financial transactions need not be determined in this same time frame and it is currently envisioned that it would be determined after the fact, as is currently the case for internal transactions in ISO-NE.

The discussion of pricing and settlement rules governing transactions scheduled day-ahead begins with the case of inter-ISO transactions that were scheduled in the day-ahead markets of both ISOs, and then proceeds to other cases.

5.4.1. Transactions Scheduled in Both Day-Ahead Markets

5.4.1.1. Market Participant Settlements

Inter-ISO transactions that clear in both day-ahead markets and are scheduled in real-time would create an inter-ISO power transfer in the day-ahead markets for settlement purposes. The Market Participant scheduling this inter-ISO power transfer would be responsible for paying any export fees for the portion of its real-time inter-ISO schedule that clears in the day-ahead market. Thus, a Market Participant that bought power in the NYISO DAM at the ISO-NE proxy bus and also sold the same quantity of power at the NYISO proxy bus in the ISO-NE DAM, would have no net position in either real-time energy market. The purchase in the NYISO day-ahead market would be offset by the scheduled export to ISO-NE. The sale in the ISO-NE day-ahead market would be covered by the scheduled import. Importantly, the level of inter-ISO transactions scheduled in the NYISO DAM would continue to be limited by inter-ISO transmission constraints. Failure to enforce these transmission constraints in the day-ahead market would lead to revenue inadequacy, just as it would today.

Example 4

Suppose, for example, that the NY DAM clears for hour 14, as shown in Figure 5, with a $48/MWh energy price at Niagara, Zone G, and at the ISO-NE proxy bus. Thus, there is no congestion related to scheduling transactions out of NY. The example ignores price differences arising from losses, to keep the example simple. BlueCo schedules a bilateral transaction from Niagara to the ISO-NE proxy bus in the NYISO DAM.[10] Assume that there is no congestion between New York and ISO-NE, so there is no charge for the inter-ISO transaction in the NYISO DAM.

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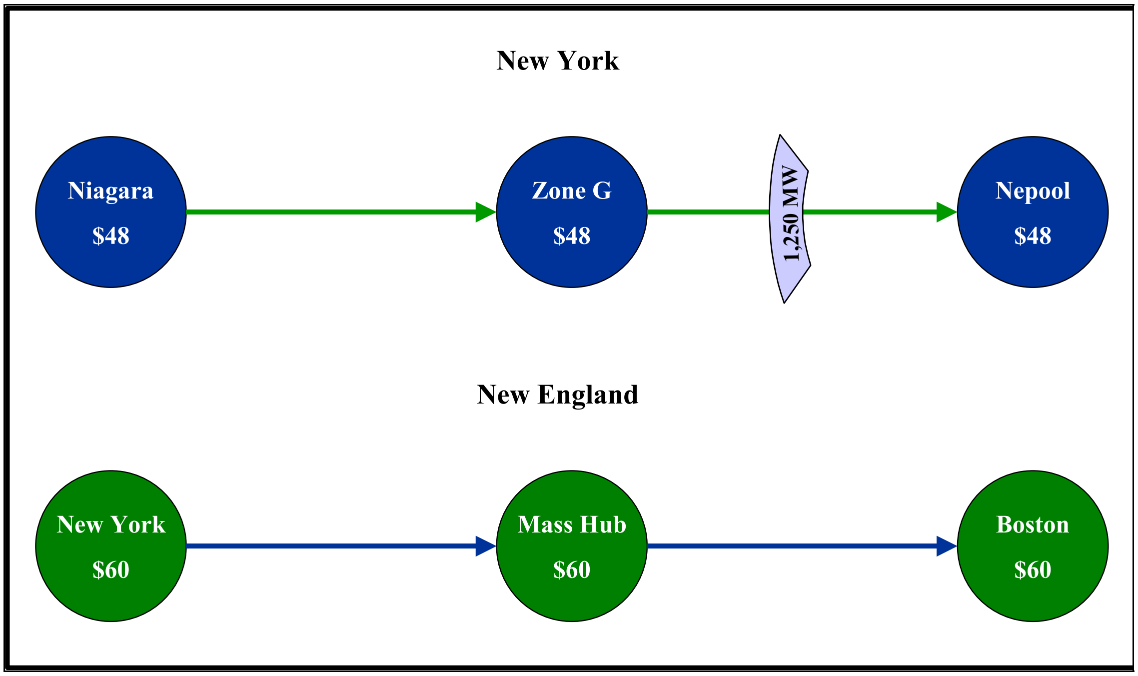
[9] An alternative approach would be to modify the ISO-NE DAM so that all inter-ISO transactions scheduled in the NYISO DAM were automatically scheduled in the ISO-NE DAM. I have stayed with the status quo.

[10] Blue offers the injection at -$1,000 at its generator in zone G and bids $1,000 for the withdrawal at the NEPOOL proxy bus.

Figure 5: Day-Ahead Prices, Hour 14



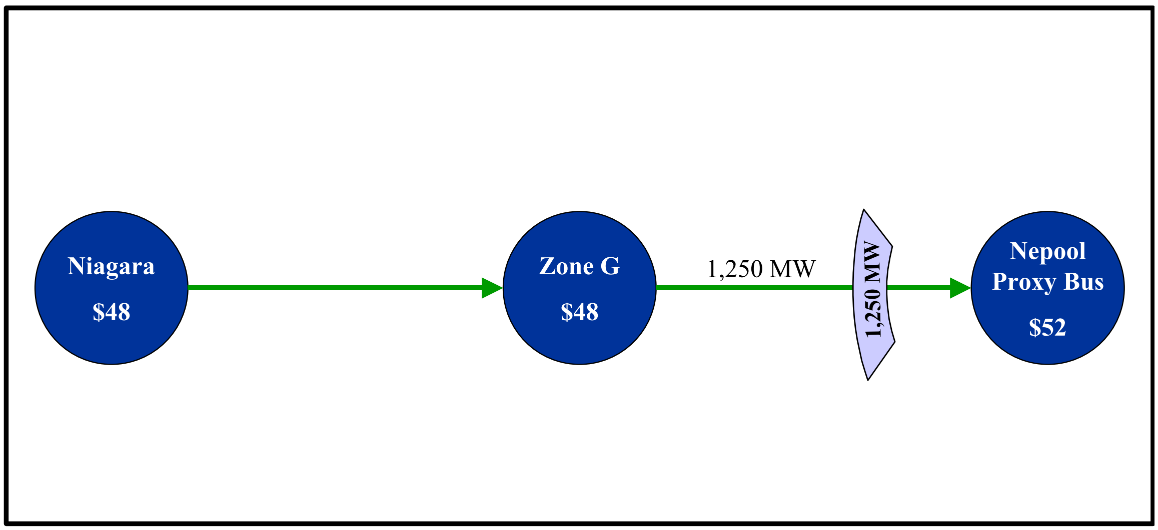
BlueCo then offers the 50 MW to the ISO-NE DAM at a zero price as an injection at the NYISO proxy bus, and it also bids 50 MW of load located in Boston into the ISO-NE DAM for hour 14 . Assume further that these transactions clear in the ISO-NE DAM. Since there is no congestion between New York and Boston in the ISO-NE day-ahead market (and we have assumed away losses to simplify the example), BlueCo also incurs no charges in the ISO-NE DAM. BlueCo then schedules the transactions to flow in real-time in the NYISO and ISO-NE real-time markets.

We then assume that the real-time prices for hour 14 are as portrayed in Figure 3 above. BlueCo would settle any deviations between the 50 MW injection that it scheduled in the NYISO DAM and its actual real-time injections at the $49/MWh real-time Niagara LMP price. The real-time transaction schedule from NYISO to ISO-NE would cover the withdrawal scheduled in the NYISO DAM. BlueCo would pay the assumed $7/MWh export fee for its real-time inter-ISO transaction schedule. In New England, BlueCo would get credit for its real-time inter-ISO import schedule, covering its day-ahead schedule. BlueCo would settle any deviations between its actual Boston load and the 50MWh load scheduled in the ISO-NE DAM at the real-time Boston LMP price, $59/MWh.

In effect, in scheduling this transaction, BlueCo has forgone the sale of its output in the NYISO DAM, incurring an opportunity cost of $48. BlueCo paid export fees of $7/MWh, and then avoided the cost of purchasing 50 MW in the ISO-NE DAM, saving $60/MW. It ends up with a net saving of $5/MWh, relative to the cost of purchasing power to meet its load in the ISO-NE DAM and selling its output in the New York DAM.

In practice, we expect arbitrage by Market Participants to cause prices in the New York and ISO-New England day-ahead markets to roughly converge to the expected level of export fees, unless transmission constraints are binding in one or both day-ahead markets. The NYISO would, however, continue to enforce the NYISO-ISO-NE transfer limit in the New York DAM, so that Market Participants' ability to arbitrage potential price differences would continue to be limited by transmission constraints. The circumstance in which the demand to schedule exports to ISO-NE in the NYISO DAM exceeds transfer capability is depicted in Figure 6. In this circumstance, the price at the ISO-NE proxy price exceeds the price in Zone G, reflecting the transmission constraints on exports. It should be noted that, while we have assumed in the example that the expected ISO-NE price is $60/MWh, the price at the ISO-NE proxy bus price is only $52/MWh in this example, reflecting the impact of the export fees that would be paid if the transaction were scheduled to flow in real-time, plus uncertainty.

Figure 6: Day-Ahead Prices with Congestion



The example portrayed in Figure 6 differs from the prior example only in that the NYISO settlements would collect $4/MWh in congestion rents in the day-ahead market.

5.4.1.2. VRD Residual

These day-ahead settlement rules have three key features that impact real-time VRD settlements. First, the existence of day-ahead schedules will not cause revenue shortfalls in VRD settlements as long as real-time VRD transactions are economic. Second, the existence of day-ahead schedules will give rise to a deficit in the VRD residual if the day-ahead schedules are economic in real-time, but the scheduled physical flow in real-time is less than day-ahead schedules. That is, inefficient real-time VRD that reduces scheduled physical flows below day-ahead schedules will give rise to a revenue shortfall in the VRD account. Third, the magnitude of the deficit arising from such inefficient VRD relative to day-ahead schedules does not depend on the magnitude of real-time financial schedules, it depends only on the level of real-time scheduled physical flows. These features of the proposed settlement system are illustrated below with a series of examples.

We initially assume that the day-ahead prices are as portrayed in Figure 5, that 250 MW of inter-ISO transactions clear in both day-ahead markets and are scheduled by market participants in real-time. In addition, we assume that the real-time prices are as portrayed in Figure 3above and that the real-time scheduled physical flows are also 250MW, that is, real-time VRD schedules are zero. Under these assumptions there would be no deviations from day-ahead schedules in either real-time energy market, and the VRD account would collect $7/MWh in export fees on the 250MWh of transactions that cleared day-ahead and were scheduled to flow in real-time. The VRD account would pay $7/MWh in export fees to the New York TOs and to the NYISO for ancillary service and schedule 1 charges for the level of scheduled physical inter-ISO flows in real-time. In this example, VRD failed to converge real-time prices but there would be no surplus or deficit in the VRD settlement account, as shown in Appendix V.

We now assume that an additional 2,250 MW of financial transactions are scheduled from New York to ISO-NE in real-time and that a corresponding 2,250 MW of VRD transactions flow from ISO-NE into New York. Just as in the prior examples for real-time transactions, the introduction of financial schedules does not affect the net surplus or deficit in VRD settlements, as the charges for the financial transactions and VRD transactions are offsetting as shown in Appendix VI.

Example 4

In the next example, we assume that the level of real-time scheduled physical flows from NYISO into ISO-NE has been reduced below the level of transactions scheduled in the day-ahead market (from 250 MW to 150 MW). In addition, we assume that the day-ahead schedules would have been economic in real-time, i.e. the VRD did not produce price convergence. In effect, the ISOs scheduled VRD that has reduced the efficiency of the real-time dispatch relative to day-ahead schedules.[11] Appendix VIII shows that this inefficient VRD results in a revenue short-fall of $300 in the VRD account, because each transaction not scheduled to flow in real-time would reduce the cost of meeting real-time load by $3/MWh above the $7/MWh export fee. Failure to schedule this flow in real-time would therefore raise the cost of meeting load in real-time relative to the cost in the day-ahead market.

It is again important that under these settlement rules, the level of revenue shortfall in the VRD account depends only on the level of scheduled physical inter-ISO flows relative to day-ahead financial schedules, and not on the level of real-time financial schedules. As shown in Appendix VIII, even if an additional 2,250 MW of financial transactions were scheduled from New York into ISO-NE in real-time, the VRD revenue shortfall would remain $300, because the scheduling payments for the financial transactions would fund corresponding payments from the VRD account for offsetting VRD transactions.

5.4.2. Transactions Scheduled in the NYISO Day-Ahead Market Only

5.4.2.1. Market Participant Schedules

Market Participant inter-ISO Transactions scheduled in the NYISO day-ahead market but not clearing in the ISO-NE day-ahead market, or not scheduled to flow in real-time, would become virtual demand bids in the NYISO market at the ISO-NE proxy

[11] This is not the intention of the VRD proposal, but the settlement rules need to account for this outcome during individual dispatch intervals or hours.

bus, and would not give rise to a day-ahead inter-ISO power transfer for settlement purposes. There would also be no obligation to pay export fees for these transactions, as they would not be treated as exports for settlement purposes. Thus, an imbalance would arise if a Market Participant purchasing energy at the NYISO proxy bus for ISO-NE in the NYISO DAM did not submit the transaction to the ISO-NE day-ahead market, nor schedule it as an import into the ISO-NE real-time scheduling process. The Market Participant would settle its imbalance by selling the power it scheduled in the NYISO day-ahead market at the NYISO real-time ISO-NE proxy bus price.

Accordingly, suppose that BlueCo purchased 250 MW at $48/MWh in the NYISO DAM, and also scheduled a 250 MW export from New York to ISO-NE, but then did not submit the transaction to the ISO-NE real-time scheduling process. BlueCo would then have no day-ahead inter-ISO schedule, and would incur a positive deviation in the NYISO real-time market, relative to its day-ahead schedule (since it bought power day-ahead, but did not dispose of it as an export in real-time). It would sell back the energy it purchased day-ahead at the NYISO real-time price, $49/MWh in **Error! Reference source not found.**.

5.4.2.2. VRD Settlements

Appendix IX illustrates the application of this settlement rule in the circumstance in which there is congestion in real-time. We suppose that BlueCo buys 250 MW of energy and schedules 250MW of exports in the NYISO DAM, but fails to schedule this transaction in the ISO-NE real-time scheduling process. ISO-NE then fully schedules the NYISO/ISO-NE interface with 1,250 MW of transactions from other market participants, and these transactions all flow in real-time, with power purchased in the NYISO real-time market to cover their exports.

If the real-time prices are as portrayed in Figure 3, there are net purchases of 1,000 MWh of energy for export in the NYISO real-time market, with gross purchases of 1,250 MWh and sales of 250 MWh, and both the NYISO and ISO-NE real-time markets are revenue adequate.

5.5. Scheduled in ISO-NE DAM Only

Inter-ISO transactions scheduled in the ISO-NE day-ahead market, but not scheduled in the NYISO DAM, nor scheduled to flow in real-time, would be settled as virtual demand bids at ISO-NE's New York proxy bus. Such transaction would not give rise to inter-ISO day-ahead power transfers for settlement purposes, nor would they give rise to any obligation to pay export fees.

5.6. Allocation of Residual Surplus

As described above, the VRD account would generate three separable revenue streams. The first would be the export fees payable on scheduled physical interchange. This revenue stream would be collected in VRD prices and then transferred to the appropriate transmission owners or ISO ancillary service or schedule 1 accounts. The second revenue stream would be the congestion rents collected in real-time when the transmission system is fully utilized and the price difference between New York and ISO-NE exceeds the export charge. The allocation of these congestion rents needs to be determined. Third, there is a residual component arising from failure of VRD to produce price convergence or inefficient real-time scheduled flows. This residual is likely to be negative, i.e. it is likely to entail an uplift payment, rather than a revenue credit and is likely to arise from situations in which the scheduled physical flow of power is from the high priced region to the low priced region. To avoid subsidizing inefficient pricing, it is proposed that this third component of the VRD account, these uplift costs, would be allocated to load in the importing area during each hour.[12]

6. Going Forward

Over the next few months, the ISOs will further develop the Virtual Regional Dispatch. Among the outstanding issues are the following:

1. Proxy buses – location and number.
2. Export charges/out-service fees.
3. Controllable lines.
4. Residual fund distribution.

[12] This rule assures that if differing shortage pricing rules result in purchases at high prices for sale in a reserve short region at lower prices, this uplift cost will be assigned to load in the reserve short importing region, not to load in the exporting region.

7. Appendices

Appendix I

Virtual Regional Dispatch Example

Real time Settlements Example

Example Description

No Day Ahead market participant transactions,
Real time Part. Sale of 100mw from NY to NE
250 MW Scheduled interchange
Prices near convergence

NY Day Ahead Interchange Clearing		NE Day Ahead Interchange Clearing	
Sales to NE	0	Receipts from NY	0
Receipts from NE	0	Sales to NY	0
Net interchange into NY (Neg is sale to NE)	0	Net Interchange into NE (negative is sale to NY)	0

Real time Participant Interchange transactions

Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	0	Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	0
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0	Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
NEPOOL Day-Ahead in NYISO RT	0		
Real time only transactions net into NY (Neg. is sale into NE)	(100)	Real time only transactions net into NE (Neg. is sale into NY)	100
Net Part. Real time Transaction into NY (NY and NE must share same Net)	(100)	Net Part. Real time Transaction into NE (Negative is sale to NY)	100
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(250)	Physical Real time interchange into NE (mw) (ISO VRD schedule)	250

NY Real Time Settlements			NE Real Time Settlements			
NY LBMP ($/mw)	49		NE LMP ($/mw)	59		
Out Service Charge ($/mwh)	7		Out Service Charge ($/mwh)	5		
	mwh	Real time Settlements $		mwh	Real time Settlements $	New Settlements Calculation
Load Change from D.A (neg. is less load)	0	0	Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	(100)	(4,900)	R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	100	5,900	Existing Step
Generation Change from D.A.	250	12,250	Generation Change from D.A.	(250)	(14,750)	Existing Step
Joint VRD Fund purchase (neg is sale)	(150)	(7,350)	Joint VRD Fund purchase (neg is sale)	150	8,850	New step
Total		**0**	Total		**0**	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	(7350)	$
Energy Charges from NE Settlements	8850	$
Out Service Charges on DAM transactions	0	
Out Service Charges on DAM/RT transactions	0	
Out Service Changes - payments to Tos	(1750)	$
RT above DAM	0	
Real time inter-ISO transaction charges collected	1000	
Net VRD Imbalance for Distribution	**750**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	0	0
Real time only transactions	(100)	100
VRD schedule to Control Area (negative = sale)	(150)	150
Net Physical Interchange to NY	**(250)**	**250**

CONCLUSION

The real-time transactions would generate $2500 in VRD residuals. Of this $2500, $1750 would be utilized to settle the export charges of $7/MWh while the remaining $750 would be a VRD residual surplus

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Appendix II

Virtual Regional Dispatch Example

Example Description

Same conditions as Appendix I altered by large market participant Real-time financial transactions far in excess of physical schedule.

NY Day Ahead Interchange Clearing		**NE Day Ahead Interchange Clearing**	
Sales to NE	0	Receipts from NY	0
Receipts from NE	0	Sales to NY	0
Net interchange into NY (Neg is sale to NE)	0	Net Interchange into NE (negative is sale to NY)	0

Real time Participant Interchange transactions			
Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	0	Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	0
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0	Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
NEPOOL Day-Ahead in NYISO RT	0		
Real time only transactions net into NY (Neg. is sale into NE)	(2500)	Real time only transactions net into NE (Neg. is sale into NY)	2500
Net Part. Real time Transaction into NY (NY and NE must share same Net)	(2500)	Net Part. Real time Transaction into NE (Negative is sale to NY)	2500
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(250)	Physical Real time interchange into NE (mw) (ISO VRD schedule)	250

NY Real Time Settlements	mwh	Real time Settlements $	**NE Real Time Settlements**	mwh	Real time Settlements $	New Settlements Calculation
NY LBMP ($/mw)	49		NE LMP ($/mw)	59		
Out Service Charge ($/mwh)	7		Out Service Charge ($/mwh)	5		
Load Change from D.A (neg. is less load)	0	0	Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	(2500)	(122,500)	R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	2500	147,500	Existing Step
Generation Change from D.A.	250	12,250	Generation Change from D.A.	(250)	(14,750)	Existing Step
Joint VRD Fund purchase (neg is sale)	2250	110,250	Joint VRD Fund purchase (neg is sale)	(2250)	(132,750)	New step
	Total	**0**		Total	**0**	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	110250	$
Energy Charges from NE Settlements	(132750)	$
Out Service Charges on DAM transactions	0	
Out Service Charges on DAM/RT transactions	0	
Out Service Changes - payments to Tos	(1750)	$
RT above DAM	0	
Real time inter-ISO transaction charges collected	25000	
Net VRD Imbalance for Distribution	**750**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	0	0
Real time only transactions	(2,500)	2,500
VRD schedule to Control Area (negative = sale)	2,250	(2,250)
Net Physical Interchange to NY	**(250)**	**250**

CONCLUSION

The additional 2250MW of financial inter-ISO schedules from NYISO into NEPOOL would pay $10/MWh for each each MWh scheduled, whilel the offsetting 2250 of additional inter-ISO VRD schedules would be paid $10/MWh for each MW of VRD schedule. The transaction charges for the market participant and VRD transactions would be offsetting, and the VRD transactions would be revenue neutral without regard to the level of real-time prices.

Appendix III

Virtual Regional Dispatch Example

Example Description

No Day Ahead Transactions,
100 mw Real-time Part from NY to NE
250 Physical schedule NY to NE
Scheduled Physical flow from high cost area to low cost area

NY Day Ahead Interchange Clearing	
Sales to NE	0
Receipts from NE	0
Net interchange into NY (Neg is sale to NE)	0

NE Day Ahead Interchange Clearing	
Receipts from NY	0
Sales to NY	0
Net Interchange into NE (negative is sale to NY)	0

Real time Participant Interchange transactions

NY	
Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	0
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0
NEPOOL Day-Ahead in NYISO RT	0
Real time only transactions net into NY (Neg. is sale into NE)	(100)
Net Part. Real time Transaction into NY (NY and NE must share same Net)	(100)
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(250)

NE	
Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	0
Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
Real time only transactions net into NE (Neg. is sale into NY)	100
Net Part. Real time Transaction into NE (Negative is sale to NY)	100
Physical Real time interchange into NE (mw) (ISO VRD schedule)	250

NY Real Time Settlements

NY LBMP ($/mw)	59
Out Service Charge ($/mwh)	7

	mwh	Real time Settlements $
Load Change from D.A (neg. is less load)	0	0
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	(100)	(5,900)
Generation Change from D.A.	250	14,750
Joint VRD Fund purchase (neg is sale)	(150)	(8,850)
Total		**0**

NE Real Time Settlements

NE LMP ($/mw)	54
Out Service Charge ($/mwh)	5

	mwh	Real time Settlements $	New Settlements Calculation
Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	100	5,400	Existing Step
Generation Change from D.A.	(250)	(13,500)	Existing Step
Joint VRD Fund purchase (neg is sale)	150	8,100	New step
Total		**0**	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	(8850)	$
Energy Charges from NE Settlements	8100	$
Out Service Charges on DAM transactions	0	
Out Service Charges on DAM/RT transactions	0	
Out Service Changes - payments to Tos	(1750)	$
RT above DAM	0	
Real time inter-ISO transaction charges collected	(500)	
Net VRD Imbalance for Distribution	**(3000)**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	0	0
Real time only transactions	(100)	100
VRD schedule to Control Area (negative = sale)	(150)	150
Net Physical Interchange to NY	**(250)**	**250**

CONCLUSION

VRD residual account of minus 250MW with export charges of $1750 ($7 times the 250MW scheduled physical flow)
VRD net imbalance of negative $3,000

Appendix IV

Virtual Regional Dispatch Example

Example Description

Same as Appendix III but with very large market participant Real-time financial transactions that greatly exceed physical schedules.

NY Day Ahead Interchange Clearing		**NE Day Ahead Interchange Clearing**	
Sales to NE	0	Receipts from NY	0
Receipts from NE	0	Sales to NY	0
Net interchange into NY (Neg is sale to NE)	0	Net Interchange into NE (negative is sale to NY)	0
Real time Participant Interchange transactions			
Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	0	Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	0
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0	Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
NEPOOL Day-Ahead in NYISO RT	0		
Real time only transactions net into NY (Neg. is sale into NE)	(2500)	Real time only transactions net into NE (Neg. is sale into NY)	2500
Net Part. Real time Transaction into NY (NY and NE must share same Net)	(2500)	Net Part. Real time Transaction into NE (Negative is sale to NY)	2500
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(250)	Physical Real time interchange into NE (mw) (ISO VRD schedule)	250

NY Real Time Settlements			**NE Real Time Settlements**			
NY LBMP ($/mw)	59		NE LMP ($/mw)	54		
Out Service Charge ($/mwh)	7		Out Service Charge ($/mwh)	5		
	mwh	Real time Settlements $		mwh	Real time Settlements $	New Settlements Calculation
Load Change from D.A (neg. is less load)	0	0	Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	(2500)	(147,500)	R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	2500	135,000	Existing Step
Generation Change from D.A.	250	14,750	Generation Change from D.A.	(250)	(13,500)	Existing Step
Joint VRD Fund purchase (neg is sale)	2250	132,750	Joint VRD Fund purchase (neg is sale)	(2250)	(121,500)	New step
Total		**0**	Total		**0**	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	132750	$
Energy Charges from NE Settlements	(121500)	$
Out Service Charges on DAM transactions	0	
Out Service Charges on DAM/RT transactions	0	
Out Service Changes - payments to Tos	(1750)	$
RT above DAM	0	
Real time inter-ISO transaction charges collected	(12500)	
Net VRD Imbalance for Distribution	**(3000)**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	0	0
Real time only transactions	(2,500)	2,500
VRD schedule to Control Area (negative = sale)	2,250	(2,250)
Net Physical Interchange to NY	**(250)**	**250**

CONCLUSION

The introduction of financial schedules does not affect the net surplus or deficit in VRD settlements

Appendix V

Virtual Regional Dispatch Example

Example Description

Day Ahead market participant transactions all carried into Real-time
Physical schedule equals sum of market participant schedule
Prices not fully converged

NY Day Ahead Interchange Clearing		NE Day Ahead Interchange Clearing	
Sales to NE	250	Receipts from NY	250
Receipts from NE	0	Sales to NY	0
Net interchange into NY (Neg is sale to NE)	(250)	Net Interchange into NE (negative is sale to NY)	250

Real time Participant Interchange transactions			
Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	250	Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	250
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0	Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
NEPOOL Day-Ahead in NYISO RT	0		
Real time only transactions net into NY (Neg. is sale into NE)	0	Real time only transactions net into NE (Neg. is sale into NY)	0
Net Part. Real time Transaction into NY (NY and NE must share same Net)	(250)	Net Part. Real time Transaction into NE (Negative is sale to NY)	250
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(250)	Physical Real time interchange into NE (mw) (ISO VRD schedule)	250

NY Real Time Settlements			NE Real Time Settlements			
NY LBMP ($/mw)	49		NE LMP ($/mw)	59		
Out Service Charge ($/mwh)	7		Out Service Charge ($/mwh)	5		
	mwh	Real time Settlements $		mwh	Real time Settlements $	New Settlements Calculation
Load Change from D.A (neg. is less load)	0	0	Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	0	0	R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	0	0	Existing Step
Generation Change from D.A.	0	0	Generation Change from D.A.	0	0	Existing Step
Joint VRD Fund purchase (neg is sale)	0	0	Joint VRD Fund purchase (neg is sale)	0	0	New step
Total		**0**	Total		**0**	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	0	$
Energy Charges from NE Settlements	0	$
Out Service Charges on DAM transactions	1750	
Out Service Charges on DAM/RT transactions	0	
Out Service Changes - payments to Tos	(1750)	$
RT above DAM	0	
Real time inter-ISO transaction charges collected	0	
Net VRD Imbalance for Distribution	**0**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	0	0
Real time only transactions	0	0
VRD schedule to Control Area (negative = sale)	0	0
Net Physical Interchange to NY	**0**	**0**

CONCLUSION

Introduction of settlements for day-ahead schedules can preserve revenue adequacy of VRD settlements.

Appendix VI

Virtual Regional Dispatch Example

Example Description

Same as Appendix V but large Real-time market participant transactions in excess of physical schedules.

NY Day Ahead Interchange Clearing		NE Day Ahead Interchange Clearing	
Sales to NE	250	Receipts from NY	250
Receipts from NE	0	Sales to NY	0
Net interchange into NY (Neg is sale to NE)	(250)	Net Interchange into NE (negative is sale to NY)	250

Real time Participant Interchange transactions			
Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	250	Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	250
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0	Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
NEPOOL Day-Ahead in NYISO RT	0		
Real time only transactions net into NY (Neg. is sale into NE)	2250	Real time only transactions net into NE (Neg. is sale into NNY)	(2250)
Net Part. Real time Transaction into NY (NY and NE must share same Net)	2000	Net Part. Real time Transaction into NE (Negative is sale to NY)	(2000)
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(250)	Physical Real time interchange into NE (mw) (ISO VRD schedule)	250

NY Real Time Settlements			NE Real Time Settlements			
NY LBMP ($/mw)	49		NE LMP ($/mw)	59		
Out Service Charge ($/mwh)	7		Out Service Charge ($/mwh)	5		
	mwh	Real time Settlements $		mwh	Real time Settlements $	New Settlements Calculation
Load Change from D.A (neg. is less load)	0	0	Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	2250	110,250	R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	(2250)	(132,750)	Existing Step
Generation Change from D.A.	0	0	Generation Change from D.A.	0	0	Existing Step
Joint VRD Fund purchase (neg is sale)	(2250)	(110,250)	Joint VRD Fund purchase (neg is sale)	2250	132,750	New step
	Total	0		Total	0	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	(110250)	$
Energy Charges from NE Settlements	132750	$
Out Service Charges on DAM transactions	1750	
Out Service Charges on DAM/RT transactions	0	
Out Service Changes - payments to Tos	(1750)	$
RT above DAM	0	
Real time inter-ISO transaction charges collected	(22500)	
Net VRD Imbalance for Distribution	**0**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	(250)	250
Real time only transactions	2,250	(2,250)
VRD schedule to Control Area (negative = sale)	(2,250)	2,250
Net Physical Interchange to NY	**(250)**	**250**

CONCLUSION

Introduction of settlements for day-ahead schedules can preserve revenue adequacy of VRD settlements.

Appendix VII

Virtual Regional Dispatch Example

Example Description

VRD reduces the efficiency of the real-time dispatch relative to market participant Day-ahead schedules.

NY Day Ahead Interchange Clearing		NE Day Ahead Interchange Clearing	
Sales to NE	250	Receipts from NY	250
Receipts from NE	0	Sales to NY	0
Net interchange into NY (Neg is sale to NE)	(250)	Net Interchange into NE (negative is sale to NY)	250
Real time Participant Interchange transactions			
Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	250	Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	250
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0	Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
NEPOOL Day-Ahead in NYISO RT	0		
Real time only transactions net into NY (Neg. is sale into NE)	0	Real time only transactions net into NE (Neg. is sale into NY)	0
Net Part. Real time Transaction into NY (NY and NE must share same Net)	(250)	Net Part. Real time Transaction into NE (Negative is sale to NY)	250
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(150)	Physical Real time interchange into NE (mw) (ISO VRD schedule)	150

NY Real Time Settlements		NE Real Time Settlements	
NY LBMP ($/mw)	49	NE LMP ($/mw)	59
Out Service Change ($/mwh)	7	Out Service Change ($/mwh)	5

	mwh	Real time Settlements $		mwh	Real time Settlements $	New Settlements Calculation
Load Change from D.A (neg. is less load)	0	0	Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	0	0	R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	0	0	Existing Step
Generation Change from D.A.	(100)	(4,900)	Generation Change from D.A.	100	5,900	Existing Step
Joint VRD Fund purchase (neg is sale)	100	4,900	Joint VRD Fund purchase (neg is sale)	(100)	(5,900)	New step
	Total	**0**		Total	**0**	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	4900	$
Energy Charges from NE Settlements	(5900)	$
Out Service Charges on DAM transactions	1750	
Out Service Charges on DAM/RT transactions	0	
Out Service Changes - payments to Tos	(1050)	$
RT above DAM	0	
Real time inter-ISO transaction charges collected	0	
Net VRD Imbalance for Distribution	**(300)**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	0	0
Real time only transactions	0	0
VRD schedule to Control Area (negative = sale)	100	(100)
Net Physical Interchange to NY	**100**	**(100)**

CONCLUSION

Inefficient VRD relative to Day-ahead schedules results in a revenue short-fall of $300 in the VRD account, because each transaction (mwh) not scheduled would have reduced costs by $3/MWh more than the $7/MWh export charge.

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Appendix VIII

Virtual Regional Dispatch Example

Example Description

VRD reduces the efficiency of the real-time dispatch relative to market participant Day-ahead schedules. An additional 2250MW of financial transactions scheduled from New York into NEPOOL in real-time in excess of physical schedule.

NY Day Ahead Interchange Clearing		**NE Day Ahead Interchange Clearing**	
Sales to NE	250	Receipts from NY	250
Receipts from NE	0	Sales to NY	0
Net interchange into NY (Neg is sale to NE)	(250)	Net Interchange into NE (negative is sale to NY)	250
Real time Participant Interchange transactions			
Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	250	Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	250
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0	Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
NEPOOL Day-Ahead in NYISO RT	0		
Real time only transactions net into NY (Neg. is sale into NE)	(2250)	Real time only transactions net into NE (Neg. is sale into NY)	2250
Net Part. Real time Transaction into NY (NY and NE must share same Net)	(2500)	Net Part. Real time Transaction into NE (Negative is sale to NY)	2500
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(150)	Physical Real time interchange into NE (mw) (ISO VRD schedule)	150

NY Real Time Settlements	mwh	Real time Settlements $	**NE Real Time Settlements**	mwh	Real time Settlements $	New Settlements Calculation
NY LBMP ($/mw)	49		NE LMP ($/mw)	59		
Out Service Charge ($/mwh)	7		Out Service Charge ($/mwh)	5		
Load Change from D.A (neg. is less load)	0	0	Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	(2250)	(110,250)	R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	2250	132,750	Existing Step
Generation Change from D.A.	(100)	(4,900)	Generation Change from D.A.	100	5,900	Existing Step
Joint VRD Fund purchase (neg is sale)	2350	115,150	Joint VRD Fund purchase (neg is sale)	(2350)	(138,650)	New step
	Total	**0**		Total	**0**	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	115150	$
Energy Charges from NE Settlements	(138650)	$
Out Service Charges on DAM transactions	1750	
Out Service Charges on DAM/RT transactions	0	
Out Service Changes - payments to Tos	(1050)	$
RT above DAM	0	
Real time inter-ISO transaction charges collected	22500	
Net VRD Imbalance for Distribution	**(300)**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	0	0
Real time only transactions	(2,250)	2,250
VRD schedule to Control Area (negative = sale)	2,350	(2,350)
Net Physical Interchange to NY	**100**	**(100)**

CONCLUSION

The scheduling of financial transactions in real-time does not impact the magnitude of the VRD revenue shortfall. The transaction scheduling payments on the financial transactions would fund corresponding payments from the VRD account for offsetting VRD transactions

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Appendix IX

Virtual Regional Dispatch Example

Example Description

Congestion in real-time

Combination of Day-Ahead and Real-time market participant transactions with congestion in Real-time.

NY Day Ahead Interchange Clearing		NE Day Ahead Interchange Clearing	
Sales to NE	250	Receipts from NY	1250
Receipts from NE	0	Sales to NY	0
Net interchange into NY (Neg is sale to NE)	(250)	Net Interchange into NE (negative is sale to NY)	1250

Real time Participant Interchange transactions

Day Ahead carried into Real time Sales to NE(must be <= DA Sales)	0	Day Ahead carried into Real time Receipts from NY(must be< = DA Receipts)	1250
Day Ahead carried into Real time Receipts from NE(must be <= DA receipts)	0	Day Ahead carried into Real time Sales to NY(must be <= DA Sales)	0
NEPOOL Day-Ahead in NYISO RT	(1250)		
Real time only transactions net into NY (Neg. is sale into NE)	0	Real time only transactions net into NE (Neg. is sale into NY)	0
Net Part. Real time Transaction into NY (NY and NE must share same Net)	(1250)	Net Part. Real time Transaction into NE (Negative is sale to NY)	1250
Physical Real time interchange into NY(mw) (ISO's schedule under VRD concept)	(1250)	Physical Real time interchange into NE (mw) (ISO VRD schedule)	1250

NY Real Time Settlements	mwh	Real time Settlements $	NE Real Time Settlements	mwh	Real time Settlements $	New Settlements Calculation
NY LBMP ($/mw)	49		NE LMP ($/mw)	59		
Out Service Charge ($/mwh)	7		Out Service Charge ($/mwh)	5		
Load Change from D.A (neg. is less load)	0	0	Load Change from D.A (neg. is less load)	0	0	Existing Step
R.T Transaction Energy deviations from DA (negative MW is less purchases or more sales)	(1000)	(49,000)	R.T Transaction Energy deviations from DA (neg. MW is less purchases or more sales)	0	0	Existing Step
Generation Change from D.A.	1000	49,000	Generation Change from D.A.	0	0	Existing Step
Joint VRD Fund purchase (neg is sale)	0	0	Joint VRD Fund purchase (neg is sale)	0	0	New step
Total		**0**	Total		**0**	

New Joint VRD Fund Accounting		
Energy Credits from NY Settlements	0	$
Energy Charges from NE Settlements	0	$
Out Service Charges Collected on DAM transactions	0	
Out Service Charges Collected on DAM/RT transactions	8750	
Out Service Changes - payments to Tos	0	$
RT above DAM	(8750)	
Real time inter-ISO transaction charges collected	0	
Net VRD Imbalance for Distribution	**0**	$

Settlement mwh Tie Line Accounting to physical	NY	NE
Day Ahead transaction net	0	0
Real time only transactions	0	0
VRD schedule to Control Area (negative = sale)	0	0
Net Physical Interchange to NY	0	0

CONCLUSION

NYISO and ISO-NE Day-ahead and Real-time markets are revenue adequate with congestion in Real-time.

Appendix X: Specific Issues Raised by Market Participants

In the two previous joint meetings held to discuss Virtual Regional Dispatch, New York and NEPOOL Participants raised several specific issues regarding the VRD proposal. The issues are recorded below, followed by an ISO proposed resolution, or the status of progress toward reaching a resolution.

1. Need to Cost Justify Proposal

   The white paper VRD justification included a statement from the Markets' Advisor that the collective New York/New England region would experience a $30,000,000 reduction in production cost if the NY/New England interface was fully arbitraged. Given that this number includes the elimination of multiple seams, the Participants want to know how much of the potential efficiency gain can be realized by elimination of other seams, without VRD. (Examples: elimination of Out-Service charges; or New York operating reserve charges). Arguments were made that VRD may not be needed if the other seams were eliminated first.

   Status: The NERTO study showed that jointly dispatching the two control areas would result in market efficiencies. David Patton, the ISOs' Market Advisor, showed further that reduction in New York/New England production cost should directly translate into improved market efficiency. He also showed a significant potential for savings during periods of scarcity. Dr. Patton will be asked to extend his study to measure market cost/savings in response to questions in this area.

2. Competes for Resources

   New York's SMD2 and RTS are consuming valuable ISO and Participant resources and time. New England also is planning significant market enhancements. The list of items to be resolved and/or changed before VRD can be implemented is extensive. VRD should not be allowed to interfere with committed activities, while the size of the project would seem to indicate that it might do so. There are simply too many projects moving forward at the same time.

   Status: The VRD Project will be given a lower priority than endorsed projects, and it will not be allowed to interfere with them.

3. Temporary Scarcity Proposal in NE

   Are External contracts setting prices most of the time? Would there be more benefit in getting the pricing signals right? ISOs moving in the same direction is one way to help alleviate scarcity conditions.

   Status: Proposed market changes to the reserve markets and scarcity pricing in New England, coupled with SMD2 in New York, will bring the markets closer together, but the changes do not have the potential to render the dispatch efficiency achievable with virtual dispatch.

4. Delay: Wait for RTS and Other Active Projects

BME is being phased out in New York, and RTS is being introduced. Scheduling improvements will open up new opportunities for Participants to respond to market opportunities. Fifteen-minute Participant interchange scheduling may become possible. We should consider delaying implementation of VRD until we see if the activities currently in development are, by themselves, effective in eliminating any market inefficiency. Without FERC approval of SMD2, VRD requirements could change if established at this early date.

Status: Fifteen-minute participant interchange scheduling is not practical within the VRD implementation time frame. Rapid adjustment to control area price separation is essential for efficient regional dispatch. Any market solution involving bidding, evaluation, checkout, and individual scheduling would be inherently slower and less efficient than virtual dispatch.

5. Delay: Solve Common problems first

Elimination of Out-Service fees, reduction of lead times for Participant transaction submittal, and evaluation of transactions are consistent with and part of VRD. Complete these changes and all other improvements in common with VRD first, and see if there is any arbitrage opportunity left, before proceeding with the development of VRD.

Status: Elimination of out-service fees will no doubt encourage additional trading and improve liquidity. It will not, however, address the structural problems associated with scheduling of physical transactions to control flow in a financial energy market. VRD directly addresses these persistent seams issues that are also felt to be a substantial impediment to trade. In addition, elimination of out-service fees will not address the market closing time issue that creates risks for Market Participants, such that they avoid participating in some cases.

6. Solicit Market Opinion On Why Prices Have not Converged

Market Participants asked that the ISOs give the Market Participants an opportunity to identify what they consider the causes for the markets not being fully arbitraged.

Status: The ISOs have asked for input. The causes are listed in the white paper. VRD addresses causes to which no practical solution has been found by using physical scheduling by Market Participants, or that does not create other inefficiencies or reliability problems. Solutions to some of the potential difficulties created by other solutions could result in other undesirable consequences, such as requirements for higher operating margins, fewer TCCs, and possible increases in uplift.

7. Will VRD Deteriorate Quality of Real time Price Sensitive Scheduling Decisions

Concern was raised over the possibility that with VRD, the ISOs would be scheduling price sensitive transactions and committing block energy based upon forecasted prices, only to have VRD activity distort the prices used to select and schedule the price sensitive transactions. Specific references were directed to the improvement in these functions that are expected from the RTS software deployment in New York, and the potential for VRD-scheduled interchange to corrupt the assumptions on which those scheduling decisions are made.

Status: The Physical Scheduling section of the straw proposal addresses the details of how price sensitive contracts will be scheduled. Clearly, the selection of price sensitive transactions over the virtual interface will improve when determination of which transactions flowed will be done after the fact, based upon the prices that actually materialized. Relative to other scheduling functions being carried out intra-day, indicative forecasts of the virtual interface will be performed jointly by the ISOs, for the purpose of scheduling non-virtual interfaces hour-ahead, and for even shorter-term scheduling decisions, such as 15 or 30-minute block unit commitment. The forecasts should be no less precise than the current process that encounters transactions that fail to checkout after having been tentatively schedule by the hour-ahead routines (this will not change with SMD2), and considering that VRD will likely create some improvement in price stability during forced outages.

8. Congestion Rights Understanding (Real-Time or Day-Ahead)

   The VRD proposal includes the possibility of introducing congestion hedge opportunities across interfaces. The details of how this process would work, and particularly, how the proposal applies to day-ahead and/or real-time transactions was questioned.

   Status: The Straw Proposal outlines current thinking on this issue.

9. 1385 line and Controllable lines

   The ISOs were asked to consider controllable lines, specifically the 1385 line, in the proposal.

   Status: The current VRD proposal relates to the free flowing inter-connecting tie lines only. Virtual dispatch can be expanded to controllable lines, but only after they are scheduled as a second interface for the scheduling and pricing of participants transactions. Recognizing the increased difficulty of scheduling multiple interfaces (see item 13 below), it should be possible to expand the concept to multiple New York/New England interfaces. Opportunities can be discussed during development of VRD details.

10. Improve Commitment Optimization Opportunities

    The ISOs should share sufficient cost data at one single location, in advance of any interchange schedule. Such information sharing would allow more efficient resource commitment, resulting in more efficient real-time scheduling.

    Status: Regional advanced commitment of slow-start resources is a major change to the current market design, and is not included in the Virtual Regional Dispatch concept. Virtual dispatch should result in improved regional commitment of fast-start resources.

11. Concern Over OSS Design

    New York Participant questioned if the OSS design should be reviewed, considering that VRD might change the requirements.

    Status: NYISO is not aware of any near term planned OSS development that is obviated by VRD. VRD may be an unintended beneficiary of some of the planned OSS development, including checkout improvement.

12. Counter Intuitive Flows May be Justified

The VRD white paper suggests that counter-intuitive interchange schedules are indicative of dispatch inefficiency. The pricing errors that occured within the New York historical data could be a cause. Other unavoidable and justifying real time conditions could be the cause. The individual events should be reviewed to determine if specific reasons other than lack of market response are at fault.

Status: Counter-intuitive flows are indicative of inefficiencies in the region's dispatch of generation. In such instances, high cost units are displacing lower cost generation. Participants with bi-lateral arrangements and business reasons to schedule counter-intuitive flow can continue to schedule such arrangements with VRD. The financial arrangements will flow through settlements. Virtual dispatch should result in the contracting parties being unaffected, or improving their financial positions when transactions are scheduled to flow in a counter-intuitive direction.

13. Complexity of Implementation with Multiple Control Areas

The complexity of efficiently adjusting interchanges becomes significantly more complex if VRD is introduced into more than one neighboring control area. Are the ISOs prepared for the possible resulting complexities?

Status: It is much easier to schedule a single virtual interface, or interfaces that are separated by congestion. The fundamental concept can work with multiple interfaces, but the optimization problem becomes much more difficult. Lessons learned in the implementation of the NY/NE VRD can be used to inform the design and development of the more complex multi-market applications.

14. Concern Over Transactions being Financial vs. Physical

With the VRD design, the ISOs will set the physical interchange schedules. Participant transactions would become financial. A concern was raised over the handling of Participant transactions that have contract terms calling for physical delivery.

Status: This issue exists within each of the markets today, both of which are financial within their borders. We will need to examine the issue and ensure that means exist (through rules or otherwise) to address the circumstance. Both ISOs have dealt successfully with similar issues in developing our current LMP based markets.