MINUTES OF THE
JOINT NEPOOL MARKETS COMMITTEE/NYISO MARKET ISSUES WORKING GROUP MEETING
HELD ON FRIDAY, JANUARY 21, 2011
IN ALBANY, NEW YORK

NEPOOL Markets Committee

Attendee	1/21		Member/ Alternate	Market Participant
A. DiGrande	✔		Chair	ISO New England Inc.
E. Abend	✔*		Member	Summit Hydropower, Inc.
			Alternate	Enbala Power Networks Inc.
K. Bekman	✔*		Member	NAEA Energy Massachusetts, LLC
			Alternate	Caithness New England Services Company, LLC
B. Bleiweis	✔		Member	DC Energy, LLC
N. Bosse	✔		Member	Brookfield Energy Marketing, Inc.
C. A. Bowie	✔*		Member	Northeast Utilities Service Company
			Temporary Alternate	NSTAR Electric Company
T. J. Brennan	✔		Member	New England Power Company
D. J. Capra	✔*		Member	International Power America
N. Chafetz	✔*		Temporary Alternate	Customized Energy Solutions for BP Energy Company, Constellation Energy Commodities Group, Inc., Energy America, LLC, Hess Corporation and Integrys Energy Services, Inc.
J. Dannels	✔		Member	Consolidated Edison Energy, Inc.
F. P. DaSilva	✔*		Member	NextEra Energy Resources, LLC
K. Dell Orto	✔*		Member	Generation Sector Provisional Group Member
			Alternate	Millenium Power Partners, LP
S. Dimou	✔*		Member	Bangor Hydro-Electric Company
M. A. Erskine	✔*		Alternate	Central Maine Power Company
F. Ettori	✔		Member	Vermont Electric Power Company, Inc.
W. Fowler	✔*		Member	Exelon New England Holdings, LLC and Granite Ridge Energy, LLC
			Alternate	Dighton Power, LLC
			Temporary Alternate	Entergy Nuclear Power Marketing LLC
P. Fuller	✔		Member	NRG Power Marketing, LLC
J. Gawronski	✔*		Member	United Illuminating Company
J. S. Gordon	✔*		Member	PSEG Energy Resources & Trade LLC
L. Guilbault	✔		Member	H.Q. Energy Services (U.S.) Inc.
R. Hart	✔*		Member	Dominion Energy Marketing, Inc.
T. Kaslow	✔*		Vice-Chair/ Member	GDF Suez Energy Resources NA/FirstLight Power Resources Management, LLC
W. Killgoar	✔*		Member	Long Island Power Authority (LIPA)
A. W. Kuznecow	✔		Secretary	ISO New England Inc.
R. B. Mackowiak	✔*		Member	Entergy Nuclear Power Marketing LLC
F. Plett	✔*		Alternate	Mass Attorney General's Office
J. A. Rotger	✔*		Member	Cross Sound Cable Company, LLC
P. P. Smith	✔*		Member	Northeast Utilities Service Company
R. de R. Stein	✔		Alternate	Signal Hill for H.Q. Energy Services (U.S.) Inc.
D. Volpe	✔*		Member	Noble Americas Gas & Power Corp.
J. Wadsworth	✔		Member	Vitol Inc.
J. Warshaw	✔*		Member	NSTAR Electric Company
S. J. Weber	✔*		Member	PPL EnergyPlus LLC
G. Will	✔		Member	MMWEC
			Temporary Alternate	CMEEC

Guest				Affiliation
J. W. Bentz	✔*			NESCOE
R. Coutu	✔			ISO New England Inc.
B. D'Antonio	✔*			MA DPU
J. Dombrowski	✔			ISO New England Inc.
J. Douglass	✔			ISO New England Inc.
J. Dwyer	✔			ISO New England Inc.
R. Ethier	✔			ISO New England Inc.
B. Feldman	✔*			Constellation Energy Commodities Group, Inc.
M. Gardner	✔*			Day Pitney
M. Harrington	✔*			NH PUC
T. J. Higgins	✔*			Waterside Power, LLC
C. Mendrala	✔			ISO New England Inc.
H. Mertens	✔*			VT DPS
R. Pelletier	✔*			MA DPU
R. Wetzel	✔*			Constellation Energy Commodities Group, Inc.
M. White	✔			ISO New England Inc.
F. Zhao	✔*			ISO New England Inc.
T. Zheng	✔*			ISO New England Inc.

* -- Indicates participated by telephone

NYISO Market Issues Working Group				
Attendee	**1/21**			**Organization**
M. Birchby	✔*			
G. Bissell	✔			Couch White, LLP for Multiple Intervenors
A. Bloom	✔*			FERC
M. Bowman	✔*			NYSDPS
R. Boyle	✔*			NYPA
C. Brown	✔			NYISO
L. Bullock	✔			NYISO
P. Caletka	✔			NYSEG
M. Cadwalader	✔*			Representing TO's
D. Chatlerjee	✔*			Midwest ISO
D. Clarke	✔*			Long Island Power Authority
D. Congel	✔			TC Ravenswood, LLC
J. Crane	✔*			Northeast Utilities
M. DeSocio	✔			NYISO
D. Eckels	✔			NYISO
A. Evans	✔			Department of Public Service
K. Feliks	✔			AEP
D. Fan	✔*			NYISO
F. Francis	✔			Brookfield Energy Marketing Inc.
H. Fromer	✔			PSEG Power NY
J. Handler	✔*			FERC
W. Heinrich	✔*			NYPSC
K. Heinz	✔*			National Grid
E. Hogan	✔*			NYSERDA
S. Jeremko	✔*			NYSEG
S. Johnson	✔			NYISO
D. Kaiman	✔*			Brookfield Power
M. Kramek	✔			Edison Mission Marketing and Trading
B. Kranz	✔			NRG Energy
M. Lampi	✔			NYISO
C. LaRoe	✔*			IPPNY
P. Leach	✔*			Camstex
S. Leuthauser	✔			HQUS
N. Mah	✔*			Con Ed Solutions
R. Mukerji	✔			NYISO
J. Nobile	✔*			Camstex
W. Palazzo	✔*			NYPA
D. Patton	✔			Potomac Economics
T. Paynter	✔			Department of Public Service
R. Pike	✔			NYISO
M. Plante	✔			H.Q. Energy Services (U.S.), Inc.
S. Rigberg	✔*			Consumer Protection Board
R. Wetzel	✔*			Constellation Energy Commodity Group
S. Wible	✔*			Calenergy
S. Williams	✔			PJM
M. Younger	✔			Slater Consulting

* -- Indicates participated by telephone

Agenda Item #1: **WELCOME**

The Chair of the NYISO Market Issues Working Group welcomed the joint meeting participants, introduced the Chair of the NEPOOL Markets Committee, and had the meeting participants including those participating by telephone identify themselves. The Chair then called upon Mr. Pike to begin the joint ISOs' presentation.

Agenda Item #2: **INTRODUCTION**

Mr. Pike (NYISO) presented a brief introduction regarding today's subject:

(1) The ISOs' proposed joint stakeholder meeting plan consists of the five meetings that have been scheduled to gather stakeholder input and develop consensus.
(2) The meetings will address discussions of the joint ISO white paper, concerns about the current practice, and the External Market Monitor's analysis.
(3) The need for joint meetings is driven by the need for a single solution for both Control Areas.
(4) The joint ISO white paper presents:
   (a) An in-depth analysis of the current market inefficiencies.
   (b) Solution options identified by the two ISOs.
   (c) Rationales for the proposed solutions.
   (d) Joint recommendations for reform from the two ISOs.
(5) The ISOs' goal for these meetings is not to update the joint ISO white paper but to use it to develop a Design Basis Document (DBD)/Concept of Operations (ConOp) that can be used as a basis for achieving an agreed-upon solution.

Mr. Pike then reviewed the schedule for the joint stakeholder meetings:

(1) Today's meeting is scheduled to discuss:
   (a) A benefit analysis of changing the current system.
   (b) Real-Time scheduling system mechanics associated with the ISO recommendations in the joint ISO white paper.
(2) The February 14th meeting will address:
   (a) Day-Ahead and Real-Time Energy Market links.
   (b) Day-Ahead External Transactions.
   (c) Details of interface settlements issues.
(3) The March 7th meeting will address:
   (a) Financial Transmission Rights (FTRs).
   (b) Net Commitment Period Compensation (NCPC).
   (c) Fees assessed at the External Nodes by the ISOs.
   (d) Conforming capacity market rule changes required.
(4) The March 28th meeting will address:
   (a) Questions and follow-up discussions from the previous meetings.
   (b) Discussion of a draft DBD/ConOp structure.
(5) The fifth meeting's agenda (as well as the potential need for more joint meetings) is open.
(6) The ISOs expect to have the initial Design Basis Document/Concept of Operations available for stakeholder review by the third (March 7th) meeting and would be looking for comments on the current proposals by February 21st in order to provide time to review any additional options proposed for this subject.

At the conclusion of Mr. Pike's remarks, the following points were raised:

(1) A meeting participant asked will this joint stakeholder group make the decisions on this subject or will this subject be addressed by the NYISO Business Issues Committee and the NEPOOL Markets Committee?
(ISOs: Mr. Pike replied that in the April/May timeframe, we plan to bring the options identified in the DBD/ConOp back to the separate stakeholder processes to select a single option to pursue for this subject. The two ISO staffs will continue to coordinate and, if necessary, we will reconvene this joint stakeholder group to keep the stakeholder processes on a parallel path. After the single option is voted on in both New York and New England, we would expect to spend the summer developing market rules based on the DBD/ConOp with approvals in the September/October timeframe followed by a FERC filing.)

(2) A meeting participant asked what if the two sets of stakeholders choose different options.
(ISOs: Mr. Pike replied that we will be trying to avoid that outcome by working through issues and differences during the joint stakeholder meeting process.)

Agenda Item #3: **REAL-TIME INTERFACE SCHEDULING: INEFFICIENCIES AND CAUSES**

Dr. White (ISO-NE) presented the Real-Time Interface Scheduling (Inefficiencies and Causes) topic to the joint stakeholder meeting attendees:

(1) With the start of this multi-month process, the ISOs want to convey more details on the problems they currently see at the interface between New York and New England including:
  (a) Real-Time net schedules from the high cost area to the low cost area occur over 4000 hours per year.
  (b) The tie is substantially under scheduled for more than 4000 hours per year.
  (c) These two results are the opposite of the results we would expect from an efficient market.

(2) Calling attention to the scatter graph on slide #7 of the presentation, Dr. White noted:
  (a) This slide depicts east to west flows when there is a difference in the proxy bus prices and the price is higher in ISO-NE.
  (b) The graph omits hours when the Total Transfer Capability (TTC) is a binding constraint on the ties.
  (c) The red dots depict counter-intuitive flows and constitute approximately one-half of the hours in the year.
  (d) The blue dots indicate flows from the low cost area to the high cost area; however, their spread indicates that a greater amount of MWh could flow in this direction. The average price differential is about $12 per MWh with a large number of MWh available.
  (e) The vertical axis uses a logarithmic scale.
  (f) Slide #8 of the presentation provides the same information and similar results when the proxy bus prices are higher in NYISO.

At this point in the discussion, the following points were raised:

(1) A meeting participant asked have the ISOs controlled for out of market contract obligations (i.e., where payments are made outside the two ISO markets). For example NYPA contracts and schedules associated with claiming Renewable Energy Credits have obligations which require external transactions to flow regardless of market conditions.

(ISOs: Dr. White replied no. The information provided on these charts is based on raw data. This raises the question of how to interpret these results. Renewable Energy Credits, Renewable Portfolio Standards, capacity-backed contracts, and other out of market contract obligations can create flows from the high cost area to the low cost area. It appears, however, that when these flows occur, no other party steps in to schedule counter-flow transactions. This appears to be a decision made for business reasons based on the current rules. This is a failure of arbitrage that we need to address.)

(2) A meeting participant noted that in 2008 ISO-NE submitted an exigent circumstances filing to FERC to address any potential market manipulation efforts by Market Participants scheduling such counter-flow transactions. How can we schedule counter-flow transactions without the being cited by the ISOs or the FERC regarding the potential market manipulation subject?
(ISOs: Dr. White replied that there are two issues being raised here. Unwinding your Day-Ahead transaction schedule with multiple countervailing Real-Time transactions may raise a concern about "wash transactions" but we have also seen no unaffiliated Market Participants reacting to the price differences created by transactions that flow from the high cost area to the low cost area either. This indicates to us that there is a market design problem.)

(3) A meeting participant asked if similar scatter plot information was available for the Norwalk-Long Island interface.
(ISOs: Dr. White replied yes, we have that data. Generally, we see more efficient use in Real-Time and do not see as much reversal in the direction of flows at the Norwalk-Long Island interface.)
The meeting participant stated that he would like to see a similar scatter plot graph for the Norwalk-Long Island interface.
(ISOs: Dr. White stated that the ISOs have the data and can create the graph.)

(4) A meeting participant asked how many data points were represented in two quadrants of the graphs shown on slides #7 and #8 of the presentation.
(ISOs: Dr. White replied the exact figures can be provided after the meeting, roughly a quarter of the hours each year are shown in each quadrant.)
The meeting participant stated that the two graphs show net flow. Did the ISOs look at the gross numbers as well? Where the ties are scheduled at 600 MW in each direction, the net flow is zero but there would be significant market activity. This could be a competitive market that is utilizing the available tie space.
(ISOs: Dr. White replied the net schedule, not gross schedules in both directions, drives pool dispatch and thus prices. If we saw a net schedule of 0 with 600 MW cleared east bound and 600 MW cleared west bound for an hour and there is a $12 differential between the two control areas' proxy bus prices, we would not conclude that the market was working well as there would still be a relatively large price differential with significant transmission capacity available for arbitrage transactions. There may be more than one way to interpret the gross flows.)

(5) A meeting participant asked if there are differences in the price between the two ISOs and there are transactions flowing from the high cost area to the low cost area and there is 1000 MW of free space, how is the amount to be scheduled to achieve an efficient outcome determined. How do you determine how many MW could be scheduled before prices turn around? Is this determination based on production costs?
(ISOs: Dr. White answered that determination cannot be read directly from this data. One would need to walk up the offer stack in one ISO and then back down the offer stack in the other ISO. To do this, one would need to know the offer/bid stacks for both control areas.

That is why the ISOs had Potomac Economics perform this analysis as the External Market Monitor has the access to all the data needed to perform this analysis. Dr. Patton will provide a more detailed response to this question in his presentation later this morning.)

Dr. White resumed his presentation with a discussion of why the situation discussed above is occurring:

(1) Reason #1: System conditions and LMPs can change frequently and in large increments. The current scheduling system (45 minutes before the hour and schedules for the full hour) does not react rapidly to changes in the LMPs.
(2) Reason #2: Application of fees and allocation of uplift to Real-Time External Transactions deter the following:
    (a) Unwinding of flow positions from the high cost area to the low cost area in Real-Time.
    (b) Arbitrage activity when tie under-utilization occurs as Real-Time is approached.
(3) These two reasons discourage a "buy low sell high" strategy because of the impact of fees and allocation of NCPC on compensation

At this point in the presentation, the following points were raised:

(1) A meeting participant stated that this subject appears to have the same concern Market Participants had in the FTR Market where price differences are due to congestion. The congestion can be addressed either by adding a generator or by adding transmission; however, pursuing either action can eliminate the congestion and in turn eliminates the value to the Market Participant taking the action. As a Market Participant, I do not know the amount of scheduled MW which will result in the price differential I seek to capture to disappear. How do Market Participants determine this value in terms of purchases or sales they should pursue?
    (ISOs: Dr. White replied that it is very difficult for the system to get to the point where it can eliminate the differential without knowledge of the slope of the two offer/bid stacks for the full set of offers. If you do not have information about the offer/bid stacks, you are shooting in the dark. You can only get it exactly right if you have the full set of market based bids.)
(2) A meeting participant said that where a Market Participant executes a transaction in the Day-Ahead Energy Market there is a financial settlement. If a Market Participant is submitting that transaction in Real-Time on a 15 minute basis banking on a price differential, the Market Participant runs the risk that its transaction will eliminate the price differential between the two control areas. Are our markets really designed to address this subject, or do we need to create a 2 hour prior to Real-Time interface market that locks in prices? On the subject of fees and uplift allocation, the meeting participant stated that he would support reducing the cost of doing business; however, we have to pay for the ISO infrastructure. These fees cannot be eliminated and we need to accept these fees as a cost of doing business.
    (ISOs: Dr. White replied that these fees can be assessed in a number of different ways. We have a full day scheduled at a future joint stakeholder meeting to review the various trade-offs in addressing these fees. The current fees act as a tax on the other control area's loads, much like the Through or Out Service Charges for external transactions that were reciprocally waived some time ago. When each other's loads are taxed, nobody wins. The ISOs will present the actual data in support of these conclusions at the future joint meeting.)

(3) A meeting participant asked if the fee elimination proposal was premised on enhancing the efficiency of the markets and whether the ISOs were presuming these costs would be eliminated so that reducing these fees would require allocating shares of the cost to someone else in order to collect the same amount of dollars.
(ISOs: Dr. White replied no to the first question and yes to the second question. There will be a displacement of higher cost generation that would be a pure efficiency improvement that would partially offset the fee shifting. If we eliminated the fees then the LMP spread will be closer to zero due to the utilization of lower cost generation on one side of the interface.) The meeting participant expressed concern that we avoid increasing uplift or moving costs out of the LMPs.
(4) A meeting participant said that when a Market Participant is flowing power it cannot hedge these costs when it is considering whether or not to submit these transactions.
(ISOs: Dr. White agreed with the statement.)

Dr. White resumed his presentation with a discussion of Real-Time LMP spreads:

(1) The price spreads change by large amounts and on a frequent basis.
(2) In 2009 (the year with the lowest volatility) flows changed direction an average of three times per day. There are days when this occurs five to ten times per day.

At this point in the discussion, the following points were raised:

(1) A meeting participant asked whether there was a correlation to the volatility of gas prices and the marginal unit in both control areas. Gas prices were stable starting in 2008 through 2009.
(ISOs: Yes. Dr. White stated that one of the phenomena observed is that volatility goes up with fuel costs in both ISOs. This tends to occur on the steep part of the supply curve.)
(2) A meeting participant noted that with PJM, there is a discussion about moving scheduling from a 15 minute basis to a five-minute basis. Would these prices be more volatile if they were not integrated hourly values?
(ISOs: Dr. White replied that the ISOs have the five-minute data and will provide the volatility measure.)
(3) A meeting participant asked whether the switching in the direction of flows would lessen with more efficient scheduling of the ties under either proposal and setting LMPs at the ties in the same manner as they are set internally.
(ISOs: Dr. White replied that the ISOs do not know about the switching amount, but the peaks of the volatility index would decrease. The LMPs are very far off each other and this happens on a frequent basis. We would need to model this to see if it would reduce the frequency of reversals.)

Dr. White returned to his presentation with a discussion of whether the flows observed were due only to changing conditions after the Real-Time schedules were set:

(1) The answer to the above question is no.
(2) At check out (i.e., 45 minutes before the hour) the ISOs see:
    (a) Substantial under-utilization of tie capacity.
    (b) Frequent and large price spreads.
    (c) Counter-intuitive flows.

(3) Today's scheduling process creates inefficient use of the ties.
(4) Today's scheduling system produces wrong-way net schedules about one-half the time.

At this point in the discussion, the following points were raised:

(1) A meeting participant said that this analysis still looks at net flows. If the ISOs were to look at gross flows, would it get a different result?
(ISOs: Dr. White replied that the ISOs do not have the gross data here. The ISOs can provide the data but would note it is subject to multiple interpretations. These charts (slides #12 and #13) do not show LMP forecast errors. We would need to perform different calculations to show price forecast errors.)
The meeting participant asked are these charts based on schedules with a known price differential.
(ISOs: Yes.)
(2) A meeting participant asked if the efficient market would try to schedule transactions to make both control area prices equal each other, what would the point be from a Market Participant perspective to transfer power from one control area to the other control area for a zero gain. Why would anyone buy and sell at the same price? This net outcome can only be accomplished with ISO intervention or by combining the two control areas into one as the transaction involves no gain and therefore no incentive.
(ISOs: Dr. White replied (1) certainly, if a Market Participant does not expect to sell for more than the price at which it had purchased, it would not sell, (2) if there are a large number of other Market Participants selling, it drives the prices down and (3) if we were at a point where there was a small price differential we would not be discussing this subject. The ISOs market design drives flows towards equalizing costs: however, if traders were getting close toward equalizing costs the ISOs would not be proposing a fix. Today these cost differences are so large that there are tens of millions of dollars of potential savings.)
(3) A meeting participant asked if a Market Participant scheduled energy from NY to NE for $45 and its offer was accepted, would the transaction be protected for the $45 price.
(ISOs: Dr. White replied if accepted at $45 it will be protected except it would be subject to NCPC charges which might eliminate any gain. It is a risk.)
The meeting participant asked whether risk avoidance makes a refusal to submit such schedules a rational response.
(ISOs: Yes.)
(4) A meeting participant asked if the price guarantee in the NYISO Hour-Ahead Market would continue to apply under the Coordinated Transaction Scheduling (CTS) option.
(ISOs: No. Dr. White stated that the offers entered under CTS do not persist for the entire hour and, since this will be a 15-minute schedule, there will be no need to guarantee pricing for the full hour.)

Dr. White summed up his presentation as follows:

(1) What should an efficient scheduling system do?
 (a) Equalize LMPs at the interface at the time the schedule is set.
 (b) Update the Real-Time schedule as fast as conditions change.
(2) Can the proposed solutions achieve the above objectives?
 (a) Equalize LMPs? Yes.

(b) Update Real-Time schedules for system conditions? Better than the current system but not perfect.

The Chair suggested that any further questions be sent to the presenters at rpike@nyiso.com and mwhite@iso-ne.com.

Agenda Item #4: **BENEFIT ANALYSIS (POTOMAC ECONOMICS)**

Dr. Patton (Potomac Economics) presented the analysis of the benefits of coordinated interchange to the meeting participants. Dr. Patton began by addressing a question frequently posed by Market Participants about the need for coordinated interchange. Shortening the lead time for scheduling even if down to 30 minutes does not achieve the needed correlation. These benefits cannot be captured without some form of explicit coordination of the two control areas. The current Potomac Economics report expands on previous analyses to estimate the relative benefits of specific proposals by comparing them with the ideal case previously presented. The focus here is on production cost benefits. Potomac Economics recognizes that the ideal cannot be achieved due to uncertainty and we evaluate the options presented to see how far from the ideal they are. The two options evaluated were:

(1) Tie Optimization: The ISOs adjust the interchange schedules based on ISO predictions of price differentials 15 minutes in advance.
(2) Interface Bidding: Schedules are adjusted only to the extent that Market Participants submit intra-hour interface bids priced below the predicted price differentials.

Dr. Patton stated in an efficient market, if the ISO forecasts were perfect, these two options should converge because Market Participants would be willing to bid at or near zero. The accuracy of the forecast impacts the risk premium likely to be included in interface bids. At this stage in the discussion, the following points were raised:

(1) A meeting participant said that when a Market Participant looks at prices an hour ahead it would be difficult to predict the spread. Are you saying this would still be difficult even five minutes before the hour?
(Potomac Economics: Dr. Patton replied that Potomac Economics did not study the five minutes before the hour scenario. For 30 minutes before the hour when power would start flowing, this prediction would be difficult for Market Participants. The ISOs have a much better ability to predict the price spread. Also, this raises the issue raised earlier at today's meeting that offers could destroy the value if too little or too much was offered. It is an aggregate of the external transactions that may switch the price value on either side. For these reasons, the ISOs can optimize in ways Market Participants cannot. This would continue to be the case even if Market Participants could submit offers and bids five minutes before the hour.)

Dr. Patton then discussed the modeling assumptions underlying the ideal case to which the proposed solutions were compared:

(1) Optimization is based on actual values on a 15-minute basis.
(2) Schedules are adjusted until the price differential is zero or an internal constraint precludes additional re-dispatch or the adjustment reaches 500 MW.

(3) The 500 MW limit is used to reflect the possibility that larger schedule adjustments would cause other interfaces to bind. We do not want to model adjustments that cannot occur in Real-Time.

Dr. Patton proceeded to summarize the modeling assumptions for the Tie Optimization proposal:

(1) The proposal uses ISO forecasts instead of the actual amounts used for the ideal case (i.e., NYISO's Real-Time Dispatch advisory price and ISO-NE's hour-ahead forecast that is used to clear Real-Time External Transactions).
(2) NYISO has a multi-period system with less potential error in its forecast.

Dr. Patton noted that he viewed these assumptions as conservative. At this stage of the discussion, the following points were raised:

(1) A meeting attendee asked whether, in the ideal case, the impact of fees and NCPC charges were ignored.
(Potomac Economics: Dr. Patton replied that Potomac Economics made an assumption that the fees and NCPC charges were eliminated and then assumed these values to be zero.)
(2) A meeting participant sought confirmation that Dr. Patton was not suggesting eliminating the charges for transactions performed by the ISOs but retaining it for Market Participant transactions.
(Potomac Economics: Dr. Patton stated that he is not providing a recommendation. He stated that he would not be opposed to eliminating the charges for Market Participants, however, it would be incorrect to apply these fees and charges to Market Participants' transactions but not to the adjustments made by the ISOs.)

Dr. Patton presented the assumptions used in his simulations including:

(1) Use of 15-minute data.
(2) A 500 MW limit on adjustments (because the simulation model cannot define the internal transmission constraints).
(3) Consumer savings was calculated as the change in Real-Time prices multiplied by the load affected (e.g., Southeast NY could be limited by a binding constraint).
(4) Negative LBMP intervals (where the NY border price was negative) were excluded. This is expected to occur far less often because ramping issues have been resolved and dynamic scheduling on the HQ Interface is planned to be implemented.
(5) Intervals at the top of an hour were excluded to account for ramp constraints and other transient price spikes.
(6) For congestion, it was assumed there would be no re-dispatch after the interface schedule is adjusted and the congestion calculation is based on active constraints.
(7) Interface bids were presumed to be linear from $0 to $10 at 500 MW in one case and from $0 to $40 at 500 MW in the other case.

Dr. Patton stated that based on the above assumptions, the production cost savings and consumer savings are summarized on slide #8 of the Potomac Economics presentation. The savings shown for 2010 do not reflect a full year. At this stage of the discussion, the following points were raised:

(1) A meeting participant asked how the production cost savings compare to the total production costs for the two pools. He noted that production costs for the two pools are several billion dollars.
(Potomac Economics: Dr. Patton replied that he did not have that comparison here but it is not a large percentage of the total production costs for the two pools.)
The meeting participant asked is it within the statistical noise of performing the analysis.
(Potomac Economics: Dr. Patton replied that on the margin these values are not small reductions and are pure efficiency gains. This is not a zero-sum game situation. These reductions are highly valuable. It is worth the effort to pursue an initiative which has a payback period of two months. These projected savings are only the production dispatch cost savings. An inefficient price signal being sent could also affect commitment and reliability evaluations (e.g., if ISO-NE assumes the Day-Ahead scheduled amounts will flow, it may end up performing Real-Time commitments that cause uplift in the millions of dollars). There is currently no good process for estimating the use of the interface and determining how much to commit because the interface is not scheduled efficiently. The ISOs can make less conservative assumptions for reliability if they know what the tie usage is likely to be.)
The meeting participant said these determinations are highly dependent on system topology and general statements like those made here today are troubling.

(2) A meeting participant asked if we do not know the direction of net flows on the tie 15 minutes prior to the hour, how do the ISOs know what to expect four hours ahead.
(Potomac Economics: Dr. Patton replied the ISOs will know that, if the costs reverse, the interface will be adjusted. This means the ISOs can rely more on the interface in setting reliability commitments. We do not account for that in these numbers. In addition, the forecasting of shortage should be improved. There are operational benefits when you start to go into a shortage as well. In December, ISO-NE curtailed exports four times but, in a coordinated system, that could be minimized. Also, whether these benefits are large or small, costs to implement these changes are relatively low and no benefit to retaining the current system over providing for more coordination has been identified.)
(ISOs: Dr. White stated that both ISOs will have more information on the direction in which ties are projected to be going and when with this project. The ISOs do not have that information at the present time. The ISOs interpret your question as do you know how much it is today. The answer is the ISOs do not.)

(3) A meeting participant asked if the study included the ability of the exporting area to commit additional resources or did the study only utilize the offer stack.
(Potomac Economics: Dr. Patton replied the study only utilized the offer stack.)

(4) A meeting participant noted that previous studies showed a five to seven million dollar increase in transactions scheduled between Long Island and ISO-NE. How much of the $17 million presented today is for transactions between Long Island and ISO-NE?
(Potomac Economics: Dr. Patton replied the transactions between Long Island and ISO-NE are not included. Potomac Economics does think, to the extent the Long Island ties can be optimized, that would be an additional benefit.)

(5) A meeting participant stated that the benefits on the Long Island ties were highly correlated with congestion into Connecticut from the rest of New England and congestion from Connecticut to Long Island. Congestion into Connecticut has been substantially reduced.

Given this reduction in congestion, how does the five to seven million dollar amount in the broader market analysis factor into this study? Did you factor in lower fuel prices and surplus?
(Potomac Economics: Dr. Patton replied that Potomac Economics utilized a fuel-adjusted amount in determining the benefits but did not reduce those benefits for congestion.)

Dr. Patton noted that, without the conservative assumptions used here, the $17 million savings could increase to $20-$30 million. Dr. Patton then presented the comparisons of the two options to the ideal case:

(1) The Tie Optimization approach yields approximately 71% of the ideal case's result in production cost savings.
(2) The Interface Bidding approach yields approximately 67% of the ideal case's result in production cost savings.
(3) For both approaches, the split of scheduling was:
  (a) 2008: 2/3 to NYISO
  (b) 2009: 50/50
  (c) 2010 (partial year): more towards ISO-NE
(4) ISO-NE recently tightened its operations to rely less often on reliability commitments.
(5) The Tie Optimization and Interface Bidding approaches result in schedules towards NYISO in about 43% of intervals and towards ISO-NE in about 42% of intervals.
(6) The adjustments are in the 200 MW to 260 MW range.
(7) The price effects are similar in both pools with consumer savings higher in New England because there is less internal congestion which results in the benefits being spread more widely.
(8) The adjusted interchange in the ideal case was 228 MW. That falls to 210 MW under the Tie Optimization approach, to 153 MW in the Interface Bidding Case #1 and to 89 MW under the Interface Bidding Case #2.

At this stage of the discussion, the following points were raised:

(1) A meeting participant asked whether, in addition to the averages presented, if there was a range.
(Potomac Economics: Yes.)
The meeting participant asked if the adjustments were capped at 500 MW.
(Potomac Economics: Yes.)
The meeting participant asked isn't it likely the ISOs would never adjust by more than 500 MW in actual practice.
(Potomac Economics: No. Dr. Patton stated that the ISOs can account directly for those factors modeled by the 500 MW limit and might be able to adjust by more than 500 MW.)
The meeting participant asked could the average adjustment be larger than 500 MW.
(Potomac Economics: Dr. Patton replied yes, however, these values would be 15-minute adjustments from a different starting point than those modeled here. The adjustments may be smaller because they are adjusting from a previously adjusted level. The chart in the presentation shows an adjustment from what actually occurred in each interval rather than cumulative adjustments to achieve the same increase.)

(2) A meeting participant asked Dr. Patton if he was stating that this project would cost around $2 million to implement and would result in $20 million in benefits.
(Potomac Economics: No. Dr. Patton stated that this project would not be extraordinarily difficult and could perhaps be done for several million dollars. Potomac Economics cannot speak for the ISOs regarding implementation costs.)
The meeting participant asked is the $20 million savings amount a tangible value or is it similar to a tax savings because the tax amount was not raised.
(Potomac Economics: Dr. Patton replied the production cost savings amount is shared by all entities and is a tangible value. The consumer price savings are more short-term in nature. Lower Real-Time pricing will likely cause less investment to be made over time and the capacity market will adjust to reflect that lack of expected investment.)
The meeting participant asked does that mean consumers would pay for this project but the production cost savings would be realized by other entities.
(Potomac Economics: Dr. Patton replied that the bulk of the production cost savings would be realized by the consumers.)

(3) A meeting participant asked can you quantify the shift of consumer savings in the energy markets to capacity cost increases.
(Potomac Economics: No. Dr. Patton stated that Potomac Economics focused on production cost savings because energy price reductions tend to be temporary as Market Participants react to the market. Reduced energy prices lead to reduced entry into the markets which may slightly increase prices in the capacity market as energy prices decrease.)

Agenda Item #5: **SOLUTION OPTIONS: REAL-TIME SCHEDULING SYSTEM DETAILS**

Dr. White presented more details of the core proposals being placed forward by the ISOs as well as the different mechanisms to eliminate counter-intuitive flows. Dr. White began his discussion with a review of the six solution elements being placed forward by the ISOs (see slide #17 of the presentation). Dr. White then moved to slide #19 of the presentation to discuss the two design options for IRIS: (1) Tie Optimization (TO) and (2) Coordinated Transaction Scheduling (CTS). Both of these design options are market based approaches. Both rely on offers/bids but they differ in the information required of Market Participants in setting the tie schedules. The ISOs determine the tie schedules today and would continue to do so under either of these proposals. At this stage in the discussion, the following points were raised:

(1) A meeting participant asked if there was a difference in the allocation of risks (i.e., socialized versus not socialized) in these proposals.
(ISOs: Dr. White stated that risks exist today, however, the risks should be reduced as we get to a shorter time horizon. When we address the Interface Settlements subject at the February 14th joint stakeholder meeting, we will discuss the risk issues in more detail. The ISOs initial thinking is that some of the risks may offset each other but at this time we do not know that for certain.)

(2) A meeting participant said he saw the risk pendulum swinging away from investors and towards consumers.
(ISOs: Dr. White replied that the ISOs are not sure that we agree with that assessment. What happens when there is a contingency that occurs in NY and the prices increase due to that contingency while power is flowing out of NY? This scenario causes the prices to remain high to the consumer. If a large contingency occurs on the NY side, those consumers pay too much

for the full hour under the current system. That risk to load is dramatically reduced by moving to a 15-minute adjustment.)

Dr. White continued with a discussion of the Tie Optimization solution:

(1) The core concept is to have the ISOs manage transmission ties between regions in the same way the ISOs manage transmission internally which would effectively be a coordinated dispatch using bid-based supply offers from all dispatchable resources setting the Real-Time tie schedule every 15 minutes.
   (a) Tie Optimization utilizes the same market-based economic dispatch logic as is used internal to each Control Area.
   (b) Each ISO currently optimizes all internal transmission flows to minimize production costs.

At this stage in the discussion, the following points were raised:

(1) A meeting participant asked if using the proxy bus would be the appropriate way to implement the Tie Optimization solution.
(ISOs: Dr. White replied if there is no congestion anywhere, yes. If one tie line in one control area's proxy bus has congestion, and the other control area's proxy bus does not, that creates an issue that the ISOs are evaluating how to address. We may need to work on the proxy bus calculation to address situations where there is congestion on one tie but not on the other ties. These issues are more implementation issues than market design issues. There are no Real-Time External Transactions as such under the Tie Optimization approach because we would be using the resource supply stacks, not Real-Time offers to buy and sell via External Transactions, to schedule the interface.)
(2) A meeting participant said that PJM's position is that by taking out the Real-Time External Transactions, the ISOs may be stepping into the space of taking positions in the market. He also noted that PJM's stakeholders do not appear to support the proposed removal of Real-Time External Transactions.
(ISOs: Dr. White stated that the ISOs do not believe they are taking positions in the market by not utilizing Real-Time External Transaction offers to set the tie schedule. If Market Participants want to enter such offers that is fine with the ISOs, however, the Tie Optimization option would not use them to schedule the tie. This argument dates back to an old ISO model (bilateral v. POOLCo) which was placed forward by Enron and others; however, the physical bilateral model for RT dispatch was never adopted. In the POOLCo advocates' view, bid-based least cost dispatch (as currently practiced by all ISOs for their internal scheduling and dispatch) was not viewed as stepping into the markets. The argument here is identical to the POOLCo arguments except that we are now talking about External Nodes. We believe the ISOs performing least-cost dispatch and providing settlement services is a proper administration of the markets. We realize PJM and MISO are considering similar issues and we are attentive to where their stakeholders are on this issue.)
(3) A meeting participant asked why we are even considering CTS given the prior discussion. We would never apply this approach regarding transfers from Massachusetts to Connecticut so why apply it for this subject?
(ISOs: Dr. White answered that the major reasons for proposing a CTS option were responsiveness to stakeholder requests that we do so, and the risk allocation issue raised in

earlier comments. The two approaches place slightly different risks on different sets of stakeholders that may lead some to prefer CTS, even though CTS is less efficient.)

(4) A meeting participant said he could see the benefits of having 15-minute transactions over the Cross Sound Cable and 1385 line like the Neptune Project proposal. This would allow for retention of the physical rights regime on the merchant facilities while receiving scheduling frequency improvements. The Tie Optimization option would be more difficult to implement in a physical rights regime.
(ISOs: Dr. White replied that the treatment of Merchant Transmission Facilities could well be different from Pool Transmission Facilities based on the need for physical transmission reservations. In ISO-NE there is currently only one such line and it has much less impact on operations than the AC lines moving gigawatt quantities back and forth between New York and New England. Operators are much more comfortable when they know what a major interface is going to do.)

At this point in the meeting, Mr. Pike began his presentation of how higher frequency scheduling would work with a discussion of the Tie Optimization option:

(1) There are significant similarities between the Tie Optimization and Coordinated Transaction System approaches in terms of how they arrive at the interface schedule.
(2) The scheduling objectives for both options are as follows:
  (a) To account for the increase or decrease in each region's (bid-based) marginal cost at the interface at varying levels of interchange.
  (b) To optimize the Real-Time schedule to minimize production cost in both regions.
  (c) To minimize the delay between the setting of the tie schedules and when the power flows.
(3) The supply curves on both sides of the interface move as the interchange schedule moves.

Mr. Pike then summarized the actions taken under the Tie Optimization approach:

(1) First, ISO-NE builds a resource supply stack at the interface which is limited by the TTC or other constraints (i.e., the Dispatch range).
(2) Second, ISO-NE passes the completed resource supply stack for deliveries to the proxy bus to NYISO.
(3) Third, NYISO integrates the ISO-NE resource supply stack in its Real-Time dispatch optimization as the incremental cost to provide power to the NYISO and the decremental cost avoided by additional flows into New England.
(4) Fourth, the optimization of the Real-Time Dispatch develops the tie flow. (The NYISO supply curve is already included in the Real-Time Dispatch.)

At this stage in the discussion, the following points were raised:

(1) A meeting participant asked how the flow across the tie would be valued in the receiving Control Area.
(ISOs: Mr. Pike replied that the flow across the tie is valued at the incremental cost to get it to the border.)
The meeting participant asked what are you using to set the LBMP in NYISO.
(ISOs: Mr. Pike replied where the curves cross, the marginal price (LBMP or LMP) at the border is the same in both ISOs.)

(2) A meeting participant asked if this meant that an import from ISO-NE could set the price in NYISO.
(ISOs: Mr. Pike answered that at the interface, there are no interface bids so we would just use the offer/bid stacks in both RTOs to set prices.)

Mr. Pike continued his presentation with a discussion of the impact of the TTC limits (slide #30 of the presentation):

(1) When the TTC binds, the prices cannot merge and we end up with price separation across the tie just like the price separation across internal constraints.
(2) This results in two prices LMP_NE and LMBP_NY on their respective sides of the interface.

At this stage in the discussion, the following points were raised:

(1) A meeting participant sought confirmation that, because the ISOs would not have total control of all resources as well as resource and transmission outages, this price separation could occur before the TTC limit is reached.
(ISOs: That is correct. Mr. Pike stated that the TTC limit could instead be another constraint.)
(2) A meeting participant said that how the ISOs set the supply curve could become an issue. He then asked how do you plan to account for the fact that we may hit internal constraints in ramping up resources. Will ISO-NE be updating the supply curve and simulating delivery to the External Node?
(ISOs: Dr. White replied that the dispatchers will be looking out 30 minutes at all times (as they do now). ISO-NE will need to condense that information to identify how it impacts the interface while considering binding interface constraints and internal shift factors and pass that information over to the NYISO every 15 minutes. This is very similar to what ISO-NE performs internally now.)
(3) A meeting participant asked how do you deal with the congestion rents.
(ISOs: Mr. Pike answered that topic, among other topics, will be the subject of the February 14th joint stakeholder meeting on Interface Settlements. This is a question of how the allocation between regions and the collection of payments will work. We will also specifically address FTRs in a subsequent joint stakeholder meeting.)
The meeting participant asked does this mean the ISOs have not thought about this subject yet.
(ISOs: No. Mr. Pike replied that there is just too much material to try to present all of the subjects at today's meeting. Both ISOs have tariff language on FTRs and congestion revenues and, for the most part, will handle congestion revenues as they do now. There are lots of details that need to wait for the later joint stakeholder meetings.)

Mr. Pike continued his presentation by noting that both ISOs' Day-Ahead Energy Markets would continue, that those Day-Ahead Energy Markets would continue to include congestion revenues, FTRs, virtual transactions, etc.; and that Day-Ahead Energy Markets would seek to emulate what will occur in Real-Time. At this stage in the discussion, the following points were raised:

(1) A meeting participant asked if the ISOs were contemplating economic dispatch of on-line units to optimize the utilization of the ties or would include commitment of additional resources.
(ISOs: Mr. Pike replied the ISOs would commit additional resources if it makes sense to commit additional resources. The ISOs need to look at Real-Time dispatch and unit commitment based on the system conditions at the time a decision is made. We would consider Real-Time commitment of flexible units just as we do today.)
The meeting participant asked if a resource is committed to meet a schedule and the flows do not materialize who pays for the minimum run time of the resource.
(ISOs: Mr. Pike answered this question is already covered in the existing tariff. It is no different from today's treatment of resources that fail check-out. Under the Tie Optimization option there should, however, be a drastically reduced likelihood of this happening.)

(2) A meeting participant asked if FTRs and Transmission Congestion Contracts (TCCs) would now be sold across the border.
(ISOs: No. Mr. Pike replied that the FTR or TCC would reach to the border but, unlike today, the FTR/TCC would include congestion at the border. Effectively, the FTR/TCC would be valued at the proxy bus so long as the congestion is reflected in the Day-Ahead Energy Market.)

(3) A meeting participant asked whether the TO and CTS options are mutually exclusive.
(ISOs: Yes.)
The meeting participant asked have you considered the chilling effect on existing External Transaction offers.
(ISOs: Yes. Mr. Pike stated that ISOs anticipate there would be no such transactions under the TO option. In Real-Time, we do not need External Transactions to schedule the tie lines. We will still have everything we have now in the Day-Ahead Energy Markets. There will be plenty of opportunity to transact. Currently, the bulk of the money and trading is in the Day-Ahead Energy Market and not in the Real-Time deviation markets. The TO approach eliminates the headaches of check-out, etc.)

(4) A meeting participant asked if a Market Participant can buy FTRs/TCCs beyond the NY-NE border.
(ISOs: Yes. Mr. Pike provided an example where the Market Participant can buy a TCC from the NYISO at a location in New York to the NY-NE border and an FTR from ISO-NE from the NY-NE border to any location in ISO-NE.)

Mr. Pike then summarized the scheduling timeline for the TO approach:

(1) Scheduling Horizon:
  (a) Looks out one hour (four 15-minute periods).
  (b) One 15-minute period is binding and the next three are advisory.
  (c) The scheduling process is accomplished every 15 minutes.
(2) Time T-20 to Time T-15:
  (a) ISO-NE runs its UDS calculations to determine an offer/bid based cost of incremental and decremental energy cost at the interface proxy.
  (b) ISO-NE passes the results to the NYISO.
(3) Time T-15:
  (a) NYISO runs Dispatch tools with ISO-NE cost as an input.

(b) Real-Time Dispatch determines the desired interface flow for the 15-minute period starting at Time T.
(c) If there are no binding constraints, equate the Real-Time LBMP with ISO-NE's expected LMP at the border.
(d) NYISO passes the Real-Time Dispatch optimization at the border to ISO-NE.
(e) Both ISOs incorporate the optimized tie schedule in scheduling in New York and New England.

At this stage in the discussion, the following points were raised:

(1) A meeting participant asked what kind of impact this scheduling timeline for the TO option would have on the running of NYISO's Hour-Ahead Market. What would be used to run the Hour-Ahead Market?
(ISOs: Mr. Pike replied that the NYISO will need to know what the ISO-NE system interchange will look like in order to set schedules with PJM and Ontario, and the HQ advisory schedules based on a forecast.)
The meeting participant asked because financially binding decisions will have been made on other interfaces, will you include uplift impacts on other borders of the Real-Time changes that take place with the New England interchange.
(ISOs: No. Mr. Pike replied we will try to adjust the schedules to minimize production costs based on our best forecasts of Real-Time conditions.)
(2) A meeting participant asked if the information ISO-NE is providing to the NYISO would include the Operating Reserve subject.
(ISOs: Dr. White replied because we co-optimize for Energy and Operating Reserves, we can account for Operating Reserve impacts. Basically, the information being provided to NYISO is the incremental cost of delivery at the border based on our dispatch of the offer/bid stack, which can include reserves if they are scarce. When commitment decisions are made, the timing of the decision matters because there are different timelines on Real-Time Commitment in NY and NE that we need to check on with our internal experts.)
(3) A meeting participant asked about resources the ISOs may commit to back a capacity transaction.
(ISOs: Dr. White stated that raises the issue of reliability commitment versus short term commitment. ISO-NE would look at starting up 30 minute resources.)
The meeting participant asked is it still a binding commitment if a contingency occurs during the T-20 period.
(ISOs: Mr. Pike stated that the ISOs will attempt to address that question at the next joint stakeholder meeting.)
(4) A meeting participant asked whether the NYISO supply curve includes Operating Reserves.
(ISOs: Yes. Mr. Pike stated that Operating Reserves is contained in the co-optimization even though what is provided to ISO-NE is the resulting Energy schedule.)

Mr. Pike resumed his discussion of the scheduling timeline. Now that we have an optimization of the two supply stacks, we need to minimize production cost and attempt to converge the LMPs (unless a constraint limits or precludes convergence).

(1) T-10 Real-Time Dispatch:

(a) Each ISO performs its internal Real-Time Dispatch with the optimized interface scheduled MW for T as an input.
(b) The ramp profile is executed from T-5 to T+5.

(2) T-5 Real-Time Dispatch:
(a) Each ISO performs its internal Real-Time Dispatch with the optimized interface scheduled MW for T as an input.
(b) The ramp profile is executed from T-5 to T+5.
(c) Begin iterative process for the next scheduling horizon.

At this stage in the discussion, the following point was raised:

(1) A meeting participant asked if any hurdle rate on the optimization from the supply stacks (e.g., $1 or less) would be proposed.
(ISOs: Mr. Pike answered no.)

Mr. Pike returned to his presentation and summarized the problems being solved with the Tie Optimization solution option:

(1) Automatically sets flow direction in economically-correct direction at the time the schedules are set (i.e., every 15 minutes).
(2) Inflexibility of the current system to respond to changes in system conditions and source of lowest cost power.
(3) Inefficient under-utilization of transmission due to too little power being scheduled in the correct direction in Real-Time.
(4) Non-transparency of interface congestion costs.

At this point the ISOs suggested that the presentation of the CTS solution be deferred until the next joint stakeholder meeting because of the weather and the fact that these materials are closely related to the materials scheduled for the next meeting. There was no objection to deferring the presentation of the CTS solution to the next meeting.

Agenda Item #6: **UPCOMING JOINT SCHEDULE AND LOGISTICS**

The ISOs repeated that the purpose of the upcoming joint stakeholder meetings is to understand, gather feedback, and refine the proposals to develop a single preferred option in a DBD by the April/May time period. The Chair then reviewed the schedule of upcoming joint stakeholder meetings:

(1) February 14th will be hosted by ISO-NE at the Springfield Sheraton. Meeting materials will be posted on the ISO-NE website with a link provided to NYISO.
(2) March 7th will be hosted by ISO-NE.
(3) March 28th will be hosted by NYISO.
(4) April 28th will be hosted by NYISO.

The timeline beyond the joint stakeholder meetings was also summarized:

(1) April-May: Advisory votes on the DBD.

(2) June-October: Stakeholder input on the respective tariffs through separate but parallel stakeholder processes.
(3) December: FERC filings of tariff language by both ISOs.

NEXT MEETING

The next meeting of the Joint NEPOOL Markets Committee/NYISO Market Issues Working Group is scheduled to be held on February 14, 2011 at the Sheraton Hotel in Springfield, MA.

Respectfully submitted,
______/s/____________
Alex W. Kuznecow
Secretary
Markets Committee