Feasibility Study for a Combined Day-Ahead Market in the Northeast

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Executive Summary

ISO-New England ("ISO-NE"), the Ontario IMO ("IMO") and the New York ISO ("NYISO") ("Northeast ISOs") have engaged LECG, LLC and KEMA Consulting, Inc. to provide a study of the feasibility of implementing a combined day-ahead electricity market for the Northeast. Such a market has a number of potential benefits, such as: facilitating electricity market trading across the region; improving the efficiency of energy, reserve and congestion management markets for the region as a whole; reducing ISO software development costs; reducing market participant transaction and hedging costs; enhancing competition; and improving regional reliability. At the same time, there are a number of practical transition issues that need to be taken into account in assessing the feasibility of a combined day-ahead electricity market and in evaluating alternative structures for implementing such a market.

This feasibility study considers seven alternative approaches for implementing a combined day-ahead market for the Northeast:

1. Separate simultaneous unit commitment and scheduling;
2. Separate sequential unit commitment and scheduling;
3. Separate iterative unit commitment with combined scheduling;
4. Separate unit commitment with data exchange and combined scheduling;
5. Hierarchical unit commitment with combined scheduling;
6. Single unit commitment with combined scheduling;
7. Single unit commitment with separate scheduling.

The study recommends that the Northeast ISOs consider a combined unit commitment with combined scheduling, achieved through either Approach 5 or 6, as the ultimate long-run structure for a combined day-ahead market in the Northeast. Approaches 5 and 6 differ primarily in terms of software implementation and definitive recommendation of one of the two will need to be based on further technical evaluation. Importantly, implementation of either approach to combined day-ahead unit commitment and scheduling would require full implementation of an interregional real-time redispatch in the Northeast. The design of such a real-time redispatch process is currently under development by PJM, ISO-NE, NYISO, and the IMO pursuant to their Memorandum of Understanding ("MOU"). Until this real-time interregional redispatch process is fully implemented, the study recommends that the Northeast ISOs implement a combined day-ahead market through a sequential approach to unit commitment and scheduling (2^{nd} approach).

A. Discussion of Recommended Approaches

The study recommends that the Northeast ISOs consider three approaches to creating a combined day-ahead market in the Northeast: the hierarchical or single unit commitment approach as the ultimate long-run market structure, preceded by the sequential approach to mitigate seams issues in the near term.

The hierarchical and single unit commitment approaches are essentially alternative software designs for creating a Northeast day-ahead market based on combined unit commitment, scheduling and pricing. These approaches have the potential to achieve many of the benefits of a combined market that are identified in Chapter IV of this study. In particular, they would improve interregional congestion management, improve the coordination of day-ahead reserve scheduling and increase day-ahead interregional transfer capability. All of these effects would serve to increase the size of the Northeast day-ahead market, which could have the further benefit of mitigating market power issues in some subregions. Importantly, under these approaches there would no longer be day-ahead interregional schedules between control areas, eliminating the possibility of day-ahead interregional scheduling mismatches.[1] While the sequential approach will also mitigate day-ahead and, possibly, hour-ahead scheduling mismatches, it is not expected to provide other benefits to the same extent as the hierarchical and single unit commitment approaches.

[1] The MOU real-time interregional redispatch process that would be used along with either the hierarchical or single unit commitment approaches would also serve to eliminate the potential for hour-ahead scheduling mismatches.

The study also identifies a number of significant implications of combined day-ahead commitment, scheduling and pricing under either Approach 5 or 6. Implementation of Approach 5 or 6 would need to be accompanied by the development of a single set of financial transmission rights to hedge day-ahead prices that include region-wide congestion costs. This would require the development of a combined auction and settlement system for these transmission rights. Implementation of these approaches would also effectively require the elimination of transaction charges on imports and exports between control areas within the combined day-ahead market, as well as ICAP recall provisions for generation exports.

The hierarchical and single unit commitment approaches to a combined market are similar in most respects but entail different approaches to addressing the potential complexity of the security analysis associated with a combined unit commitment process for the Northeast. Determining the unit commitment for a combined Northeast market will require solving a larger network model, evaluating more units, and evaluating more constraints and contingencies than do any of the individual control area unit commitment processes. These increases in scale could have a material impact on the solution time for the unit commitment process, which is a concern of both market participants and the ISOs. The hierarchical approach described in this study is a potential method for gaining almost all of the benefits of a single unit commitment model, while materially speeding the solution time relative to a single commitment model.

Without further technical evaluation and, perhaps, actual testing, it cannot be determined whether the hierarchical approach would in fact be likely to provide the majority of the benefits of a single unit commitment model, or even whether it would actually improve solution time. Nor is it certain that the solution time requirements for the single unit commitment model would be unacceptable, particularly if the unit commitment process were simplified and streamlined, for example, by removing steps used only for cost allocation purposes. These issues are not resolved in this study and require further technical evaluation and probably testing based on existing unit commitment software.

As noted above, successful development of the MOU real-time interregional redispatch mechanism has a major impact on the recommendations of this feasibility study. The two preferred long-term approaches, the hierarchical and single unit commitment approaches, effectively require full implementation of the real-time redispatch mechanism. The four Northeast ISOs are preparing for real-world testing of the real-time interregional redispatch mechanism, but full implementation has not been approved by market participants and is likely to be at least a year in the future.

Without full implementation of a coordinated interregional redispatch in real time, the day-ahead schedules determined in Approach 5 or 6, which are based on a combined regional pricing and scheduling process, would have a material likelihood of not being economically sustainable when combined with real-time dispatches and prices determined separately by each control area. This could give rise to both extreme real-time prices within individual control areas that would be unrelated to the underlying supply and demand conditions, and, potentially, to reliability problems. The implementation of Approach 5 or 6 is therefore not a short-run alternative. Instead, these approaches should be viewed as potential next steps that could be implemented once the interregional real-time redispatch process has been successfully implemented and is routinely used for combined congestion redispatch and pricing in real time.

The report therefore recommends that the Northeast ISOs implement the sequential approach to creating a combined day-ahead market in the Northeast in the near term. A key difference between the sequential approach and the hierarchical and single unit commitment approaches is that under the sequential approach the individual control areas would continue to calculate day-ahead market prices. While a single day-ahead price calculation process would enhance market efficiency if implemented in conjunction with full implementation of the interregional real-time redispatch process, such day-ahead prices would be more likely to undermine both market efficiency and reliability if implemented prior to a combined process for price determination in real time. The sequential approach to developing a combined day-ahead market for the Northeast is in practical terms, therefore, the only recommended approach that can be implemented in the near term.

The sequential approach appears likely to provide a framework within which market participants can create a combined day-ahead market that will realize many, but not all, of the potential benefits of a single day-ahead market for the Northeast, such as improved transaction scheduling, expansion of the market and improved interregional congestion hedging. Importantly, the approach does not require implementation of the real-time interregional redispatch process as a prerequisite, although it would also work better in conjunction with such a real-time interregional redispatch process. It also does not appear from this preliminary evaluation that the sequential process poses any complex market design or implementation problems that would require long development periods or raise complex cost shifting issues. On the contrary, another advantage of the sequential approach is that it appears to be quite forgiving of differences in market design across the control areas within the Northeast. This would permit them to gradually adopt more fully uniform market rules that would ease implementation of the hierarchical or single unit commitment approaches in the future.

At the same time, however, the sequential approach forgoes important potential benefits of a combined day-ahead market because it is not based on a single combined regional day-ahead pricing and scheduling process. In particular, the sequential approach has very limited potential to provide interregional congestion management or coordinated reserve scheduling in the day-ahead market. It would thus not exploit the potential for increased interregional transfer capability in the day-ahead market associated with region-wide day-ahead pricing and scheduling supported by real-time interregional redispatch. In addition, this approach would not work as well as the hierarchical or single commitment approaches for coordinating transactions between non-adjacent ISOs, such as PJM and the IMO or PJM and NEPOOL.

Therefore, while the sequential approach is implemented in the near-term, the study recommends that the Northeast ISOs simultaneously undertake to resolve the implementation uncertainties relating to the hierarchical and single unit commitment models. This would allow them to choose one or the other as the desired final model for a combined day-ahead market in the Northeast and to begin working toward implementation following full deployment of the interregional real-time redispatch process.

B. Discussion of Other Approaches

The study concludes that the first approach, based on separate simultaneous individual control area unit commitment and scheduling processes, offers relatively little scope for improved coordination in the Northeast. A particular limitation of this approach is that it would likely reduce interregional arbitrage transactions during tight supply and demand conditions (because of increased hedging costs), which would potentially exacerbate interregional price differences. In addition, this approach would provide relatively little scope for interregional coordination of unit commitment either to manage transmission congestion or meet reserve requirements.

The 3rd and 4th approaches, the iterative and data exchange approaches, are unlikely to be effective and workable mechanisms for implementing a combined day-ahead market in the Northeast. The most important considerations underlying this conclusion are that the data exchange approach does not enable sufficiently close coordination of the separate control area unit commitment processes to provide reasonable assurance that the overall unit commitment and scheduling process would lead to efficient and competitive price levels. Moreover, the data exchange approach would materially limit the potential for interregional coordination of reserves and congestion management in the day-ahead market.

The iterative approach holds out more promise for producing efficient and competitive price levels, but it is doubtful that this approach would streamline the day-ahead unit commitment and scheduling process for a combined market relative to either of the preferred long-term approaches (hierarchical or single unit commitment). The study therefore recommends that this approach not be pursued further, unless problems are identified in the course of further analysis of the hierarchical and single unit commitment.

The seventh approach, a single unit commitment process with separate control area scheduling processes, has the advantage that it could be implemented prior to a combined interregional redispatch in real time. This is made possible by the individual control area security analyses used in the price calculation and scheduling step. However, the disconnect between the combined regional security analysis used in the unit commitment step and the individual control area security analyses used in the price calculation and scheduling step potentially gives rise to an inefficient day-ahead market with extreme price levels that are unrelated to underlying supply and demand conditions.

C. Market Impacts

The most important market impact that the study identifies occurs in Approaches 3 through 7 to interregional coordination, which are fundamentally different from Approaches 1 and 2. Approaches 1 and 2, as well as the day-ahead markets existing in PJM and NYISO and approved for NEPOOL, fundamentally rely on the arbitrage activities of individual market participants to coordinate interregional transactions. In each of these markets, the reliance on decentralized decision making is accommodated by a system of day-ahead financial commitments associated with the scheduling of interregional transactions.

Approaches 3 through 7, on the other hand, effectively allow a shift in responsibility for scheduling interregional transactions from the individual arbitrageurs to the centralized unit commitment and scheduling process. Under Approaches 3 through 6, in particular, bilateral transactions across control areas in the Northeast will become financial transactions with no actual impact on the unit commitment or actual interchange schedules.

In addition, implementation of Approaches 3 though 7 will effectively require elimination of transaction charges on imports and exports between control areas within the combined day-ahead market, entail market-wide collection of congestion rents to fund market-wide financial transmission rights, and would not permit application of ICAP-based recall provisions to load participating in the combined day-ahead market.

D. Other Recommendations

Finally, the report describes and recommends a number of additional elements of a combined day-ahead market in the Northeast that relate to market interfaces, rules and pricing. These could significantly reduce market participant transactions costs independently and could be implemented independently of other changes in the day-ahead market structure, but would also contribute to reducing transactions costs within the combined market. These elements include: development of a common interface and scheduling system for all inter-control area transactions within the Northeast region, development of a common interface for the submission of generator and load bids in all of the Northeast day-ahead markets, development of a common settlement system and interface for scheduling financial bilateral transactions within the Northeast, development of a common set of financial rights hedging the congestion associated with inter-control area transactions within the Northeast, standardization of market rule terminology and structure, and implementation of an improved pricing mechanism for transactions scheduled over controllable lines.

In most cases, these changes would be desirable or even necessary for full implementation of a combined day-ahead market mechanism based on a combined Northeast pricing and scheduling process, such as either the hierarchical approach or the single commitment approach. In all cases, these changes could be implemented in conjunction with, or even prior to, the sequential day-ahead market process, providing a transition path to the end state of a single combined day-ahead market with a single day-ahead pricing mechanism. All of these changes appear to be desirable from the standpoint of developing a more efficient combined day-ahead market in the Northeast.

Chapter I. Overview

Three Northeastern ISOs (ISO-New England, the Ontario IMO and the New York ISO) have engaged LECG, LLC and KEMA Consulting, Inc. to provide a study of the feasibility of implementing a combined day-ahead electricity market for the Northeast. Such a market could potentially have a number of benefits, such as: facilitating electricity market trading across the region; improving the efficiency of energy, reserve and congestion management markets for the region as a whole; reducing ISO software development costs; reducing market participant transaction and hedging costs; enhancing competition; and improving regional reliability. At the same time, there are a number of practical transition issues that need to be examined in assessing the feasibility of such a market, such as: the impact of changes to existing day-ahead unit commitment and scheduling rules, impacts on software design and solution times, implementation costs, impacts on individual market institutions, and the potential for interregional cost shifting or gaming. These potential benefits and costs are discussed in depth in Chapter IV and draw upon ideas and concerns that were raised at meetings with market participants and the ISOs during the first half of November as well as upon discussions of seams issues in the ISO MOU (Memorandum of Understanding) process.

The structure of the report is that Chapter II summarizes the existing market structures in the Northeast, in particular, those of NEPOOL, NYISO, Ontario, PJM[2] and the Maritimes. Chapter III briefly describes the interregional real-time congestion management redispatch mechanism that is currently under development. Chapter IV discusses alternative structures for implementing a combined day-ahead market in the Northeast. Chapter V identifies and evaluates a number of steps that could be taken to develop more efficient and better coordinated day-ahead markets in the Northeast, independent of changes in the market structure. Chapter VI summarizes the potential impacts of a combined day-ahead market in the Northeast on the participating ISOs, market participants and the markets themselves.

Before turning to an evaluation of alternative mechanisms for implementing a combined day-ahead market, Chapter II, as noted above, provides a review of the existing day-ahead market mechanisms in the Northeast, including New York, NEPOOL, Ontario, PJM, and the Maritimes. The purpose of Chapter II is not to provide a complete description of every feature of these markets, nor to critique them and identify a preferred day-ahead market design. Rather, the focus of this study is on day-ahead markets from the standpoint of interregional coordination. The discussion of the various existing and prospective market designs in Chapter II is therefore focused on those elements that are relevant to coordination with other control areas in the day-ahead and hour-ahead time frame.

This feasibility study for a combined day-ahead market in the Northeast is related to, but distinct from, two other ongoing regional coordination efforts. First, the PJM OI, NYISO, ISO-NE and the Ontario IMO are engaged pursuant to the MOU in the study of the implementation of a real-time interregional congestion management redispatch process among the Northeast control areas. The real-time interregional redispatch study has progressed from conceptual development to testing of the convergence properties of the proposed system, with the next step being trial implementation between the PJM OI and NYISO. Second, there is an ongoing process of addressing seams issues in the Northeast through the work of the Seams Team of the ISO/MOU Business Practices Working Group.

This feasibility study for a combined day-ahead market complements the interregional congestion management redispatch study by addressing the market coordination issue in the framework of the day-ahead unit commitment process. It will be seen in the discussion of day-ahead market systems in Chapter IV that many of the approaches under consideration for developing a combined day-ahead market in the Northeast require full implementation of the interregional redispatch process in real time. For this reason,

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[2] Although PJM is not a participant in this study, it is interconnected with New York. Therefore, this study would be incomplete without addressing the potential means by which PJM could be included in a Northeast day-ahead market, as requested by the RFP.

Chapter III of this study provides a summary of the real-time interregional redispatch process being developed under the ISO/MOU.

The real-time interregional redispatch process, however, takes the unit commitment as given, and has developed mechanisms for inter-control area redispatch given the unit commitment. This day-ahead market study addresses many of the same issues as does the interregional redispatch study, but within the day-ahead framework. For this reason, parts of the proposed coordination mechanisms are similar to, or based upon, those developed by the interregional redispatch study. In addition, however, there are a variety of unique features of the unit commitment process that provide the focus of this study, including: the increased solution time required to solve the unit commitment, the need to take account of market power mitigation logic, provisions for reconciling forecast and bid load, and the scheduling of reserves.

The day-ahead market feasibility study is also distinct from the work of the Seams Team, although the study attempts to address some of the concerns raised in that process. The day-ahead market study is intended to look forward to identify potential end states, as well as potential transition paths, in the evolution of a combined day-ahead market in the Northeast. In general, the day-ahead market study does not attempt to identify or solve short-term market problems that are currently the focus of the Seams Team's efforts, but instead focuses on assessing the feasibility and desirability of longer-term improvements in the day-ahead market and day-ahead market processes.

Although the focus of this study is on the development of a combined day-ahead market and combined unit commitment, consideration of the current and prospective methods for creating a more effective day-ahead market process also requires consideration of the process of adjusting day-ahead schedules. The discussion in Chapter II of the current market designs, and of prospective day-ahead market mechanisms in Chapter IV, therefore includes discussion of the hour-ahead scheduling processes[3] in which day-ahead schedules are adjusted and inconsistencies eliminated.

The MOU real-time interregional redispatch mechanism also has a major impact on the recommendations of this feasibility study. Two of the preferred mechanisms for developing a combined day-ahead market in the Northeast, the hierarchical and single unit commitment approaches, effectively require full implementation of the real-time redispatch mechanism as a prerequisite. Their implementation is therefore not a short-run alternative but should instead be viewed as a potential next step that could be implemented once the interregional real-time redispatch process has been successfully implemented and is routinely used to manage congestion and redispatch generation across the region in real time.

A third approach to the development of a combined day-ahead market, the sequential approach, appears likely to provide a framework within which market participants can create a combined day-ahead market that will realize many, but not all, of the potential benefits of a single day-ahead market for the Northeast. Importantly, this approach does not require implementation of the MOU real-time interregional redispatch process as a prerequisite, although the sequential approach would also work better in conjunction with such a real-time interregional redispatch process. It also does not appear from this preliminary evaluation that the sequential process poses any complex market design or implementation problems that would require long development periods or raise complex cost shifting issues. On the contrary, another advantage of the sequential approach is that it appears to be quite forgiving of differences in market design.

A key difference between the sequential approach and the hierarchical and single unit commitment approaches is that the individual control areas would each continue to calculate day-ahead market prices under the sequential approach, whereas there would be a single set of day-ahead prices for the entire Northeast under the hierarchical or single

[3] By this we intend to refer generally to the process for scheduling inter-control area transactions. This process sometimes begins as much as two hours before real time and encompasses the activities up to the inter-control area check process which may be as little as 15 minutes before real time.

unit commitment approaches. While a single price calculation process would enhance market efficiency if combined with full implementation of the interregional real-time redispatch process, such a set of day-ahead prices would be more likely to undermine both market efficiency and reliability if implemented prior to full implementation of the interregional redispatch process in real time. The sequential approach to developing a combined day-ahead market for the Northeast is in practical terms therefore the only mechanism that can be implemented within the near term.

At the same time, however, the sequential process forgoes important benefits because it is not based on a single combined regional day-ahead pricing and scheduling process. In particular, the sequential approach has very limited potential to provide interregional congestion management or coordinated reserve scheduling in the day-ahead market. In addition, this approach would not work very well for coordinating transactions between non-adjacent ISOs, such as PJM and the IMO or PJM and NEPOOL.

The hierarchical and single unit commitment approaches are similar in most respects but entail different approaches to dealing with the complexity of the security analysis associated with the unit commitment process for a combined day-ahead market in the Northeast. Determining the unit commitment for a combined Northeast market will require solving a larger network model, evaluating more units, and evaluating more constraints and contingencies than will any of the individual control area unit commitment processes. These increases in scale can have a substantial impact on the solution time for the unit commitment process, which is a concern of market participants, as well as the ISOs. The hierarchical approach described in this study is basically a potential method for trying to get almost all the benefits of a single unit commitment model, while materially speeding the solution time relative to a single commitment model.

It cannot be determined in the abstract, however, whether the hierarchical approach would in fact be likely to provide almost all the benefits of a single unit commitment model, nor even whether it would improve solution time. Nor is it certain that the solution time of the single unit commitment model would be unacceptable, particularly if the unit commitment process were simplified by removing steps used for cost allocation purposes. These issues are not resolved in this study and require further evaluation and probably testing based on existing unit commitment software.

It is recommended in this report that the Northeast ISOs implement the sequential approach to creating a combined day-ahead market in the Northeast in the near term. It is further recommended that an effort be simultaneously made to resolve the implementation uncertainties relating to the hierarchical and single unit commitment model, allowing the Northeast ISOs to choose one or the other as the desired final model for implementing a combined day-ahead market in the Northeast. Following implementation of the real-time interregional redispatch mechanism, it would be possible to begin working toward implementation of a single combined day-ahead market for the Northeast based on one of these models.

Chapter V discusses a number of additional elements of a combined day-ahead market in the Northeast that relates to market interfaces, rules and pricing that could be implemented independent of changes in the structure of the day-ahead market but would contribute to reducing transactions costs. These elements include development of a common interface and scheduling system for all inter-control area transactions within the Northeast region, development of a common interface for the submission of generator and load bids in all of the Northeast day-ahead markets, development of a common settlement system and interface for scheduling financial bilateral transactions within the Northeast, development of a common set of financial rights hedging the congestion associated with inter-control area transactions, standardization of market rule terminology and structure, and implementation of an improved pricing mechanism for transactions scheduled over controllable lines.

In most cases these changes would be desirable or even necessary for full implementation of a combined day-ahead market mechanism such as either the hierarchical approach or the single commitment approach. In all cases, these changes could be implemented in conjunction with, or even prior to, the sequential day-ahead market process, providing a transition path to the end state of a single combined day-ahead market with a single day-ahead pricing mechanism. All of these changes appear to be desirable from the standpoint of developing a more efficient combined day-ahead market in the Northeast.

statewide, centrally-dispatched power pool for over 30 years. The NYISO is responsible for the operation of New York's high-voltage transmission grid and the administration of a wholesale electricity market in which power is purchased and sold at market-based prices.

The NYISO operates both a day-ahead and a real-time energy market, which together are known as the two-settlement system. Energy transactions and transmission usage scheduled in each of these markets are settled using Locational Based Marginal Prices ("LBMPs"). The day-ahead market determines LBMPs at each generator bus and for each load zone for each hour of the next day, while the real-time market determines the spot price used to settle real-time transactions and differences between day-ahead schedules and real-time generation and load. The NYISO also has a day-of Balancing Market Evaluation ("BME") that occurs 90 minutes prior to each hour to allow market participants to adjust their day-ahead schedules and bids. The NYISO calculates LBMP prices during the BME process, but these prices are presently used for settlements only for ancillary services and, in certain circumstances, external transactions.[4]

[4] BME prices and bids are used to price external transactions under Extraordinary Corrective Action ("ECA") 20001208B when transmission congestion exists in BME. BME bids are used under ECA 20001208A to settle external transactions that are scheduled in BME but do not flow in real-time. See Phantom transaction ECA: http://mis.nyiso.com/public/postings/ecac20001208a.pdf, and External Congestion ECA: http://mis .nyiso.com/public/postings/ecac20001208b.pdf.

1. Overview of the New York Day-Ahead Market

The New York ISO operates its day-ahead energy market using software that performs a Security-Constrained Unit Commitment ("SCUC") based on the bids of market participants. The unification of day-ahead market processes and day-ahead reliability measures results from the need to assure that the energy schedules resulting from the day-ahead market can be reliably accommodated, as well as from the objective of using markets to meet day-ahead reliability requirements.

The New York SCUC simultaneously conducts markets to commit generation to meet energy, operating reserve and regulation requirements. The market is based on bids from qualifying generation and loads to supply energy, 10-minute spinning reserves, 10-minute non-spinning reserves, 30-minute reserves[5] and regulation. Bilateral schedules are accepted in the day-ahead SCUC process, and are accompanied by decremental bids.

The SCUC software determines which bids are selected by determining those that can most cheaply meet energy and reliability requirements. Specifically, SCUC minimizes the bid-cost of serving load that has bid to be served through the day-ahead market and of ensuring that sufficient generation is committed to meet forecast load, reserve and regulation requirements. The commitment is performed using a complete model of the New York transmission system, and both transmission congestion and losses are taken into account in the selection of accepted bids. Thus, the commitment of generation to meet energy and operating reserve requirements is location specific, so as to meet security requirements in the event of either a transmission or generation contingency.

The SCUC results in energy, regulation and reserve schedules for generators and loads for each of the 24 hours of the dispatch day. It also produces day-ahead prices for energy and ancillary services. The hourly energy prices, LBMPs, are calculated for each generator location within New York, eleven load zones, and four proxy buses ("external

[5] The bid box and SCUC automatically distinguish between bids for 30-minute reserves on synchronized units and on units that are not synchronized with the system.

proxy buses") reflecting the regions bordering New York: PJM, NEPOOL, Ontario and HydroQuebec.

Day-ahead financial settlements in the NYISO day-ahead market are calculated using the hourly day-ahead prices and schedules. Energy settlements are calculated based on the day-ahead LBMPs and generator and load energy schedules. Bilateral schedules pay a day-ahead transmission usage charge ("TUC") to the ISO that is calculated from the difference between the LBMPs at the source and sink locations. Day-ahead settlements for reserves and regulation are presently based on a single market-clearing availability price.[6] Generators that are scheduled day ahead may also receive supplemental payments, like the make-whole payments in PJM, if the sum of their day-ahead energy and ancillary services revenue falls short of the bid-cost of their day-ahead schedule.

2. Products

The NYISO unit commitment and dispatch is based on six products, most of which have locational components discussed in subsection 5 below. The market produces prices and settlements for energy, 10-minute spinning reserves, 10-minute reserves, 30-minute reserves, regulation and forecast required energy for dispatch ("FRED"). The category of 10-minute reserves includes both 10-minute spinning reserves and 10-minute non-spinning reserves, which can be used interchangeably to meet the 10-minute reserve requirement.[7] The category of 30-minute reserves includes 10-minute spinning reserves, 10-minute non-spinning reserves, 30-minute spinning reserves and 30-minute non-spinning reserves, all of which can be used interchangeably to meet the total 30-minute reserve target.[8] FRED is a residual category of unpriced reserves in excess of the total

[6] The NYISO and its market participants have agreed upon the need to introduce locational pricing of reserves, so that reserve pricing would be consistent with the locational reserve constraints enforced in SCUC. Locational pricing of reserves was to be implemented November 1, 2000, but implementation has been deferred by FERC.

[7] A certain portion of the 10-minute reserve requirement must be supplied by synchronized 10-minute reserves.

[8] Because of these relationships between the operating reserve categories, the products that are priced in the market: 10-minute spinning reserves, 10-minute reserves and 30-minute reserves do not correspond exactly to the products for which market participants bid: 10-minute spinning reserves, 10-minute non-spinning reserves and 30-minute reserves.

30-minute target; FRED is scheduled when necessary to ensure that the day-ahead commitment can meet forecast load.

The NYISO products correspond closely to those in the NEPOOL tariff filed on March 31, 2000 and approved by FERC on June 28, 2000. The main exception is that NEPOOL has defined a product called four-hour reserves that, like FRED, is used to ensure that the unit commitment can meet forecast load. Four-hour reserves differ from FRED in that they are explicitly priced and may include capacity from off-line units that can be available within four hours.

3. Bidding in the Day-Ahead Market

Internal generators bidding to sell into the New York unit commitment and dispatch submit multi-part bids and other data reflecting generator status and operating parameters. The multi-part bids may include a start-up bid (in $), a bid for the minimum load energy block (in MW and $/MW), bids for incremental energy blocks, and availability bids for each category of ancillary service capacity (10-minute spinning reserve capacity, 10-minute non-spinning reserve capacity, 30-minute reserve capacity,[9] and regulation). The point of injection for internal generator bids is a specific bus on the ISO-modeled transmission system.

Incremental energy may be bid as a series of increasing blocks (number of blocks, MW/block and $/MW/block) or as a piecewise linear, positively sloped curve with $/MW as a function of MW output. Both the minimum energy and dispatchable energy bids may vary by hour, as may ancillary service bids. Ancillary service availability bids are in the form of a single price per MW for each category of capacity on each unit. Under the New York system, a generating unit may submit a bid for its capacity into more than one product market, e.g., energy and reserves. SCUC will consider all of the bids and will schedule each megawatt of capacity only once.

[9] The bid box and SCUC automatically distinguish between bids for 30-minute reserves on spinning units and on units that are not spinning with the system.

Other data regarding internal generator unit status and operating parameters that are used in the unit commitment and dispatch include: hours to start-up, minimum run time, minimum down time, maximum number of startups per day, dispatch status, measures of real and reactive capability, and ramp rates.

Suppliers outside of the New York Control Area ("NYCA") may bid into the unit commitment and dispatch by submitting incremental energy bids. The bids are made at a specific external proxy bus in the form a series of increasing blocks (MW/block and $/MW). At present, external suppliers may not include minimum run time as a bid parameter, although this is under discussion. While external suppliers may offer 10-minute non-spinning reserves and 30-minute reserves into the NYISO markets, the practical use of this opportunity is limited by current practices for setting the desired net interchange ("DNI") between New York and neighboring control areas. Since external supply offers are made at the external proxy buses, they are not generator specific, and could be sourced from the spot markets of adjacent control areas.

Load-Serving Entities ("LSEs") may participate in the New York unit commitment and dispatch by bidding the number of MWs of energy that they wish to purchase in each load zone. In addition, LSEs may submit price sensitive bids at specific internal NYISO buses at which they have load.[10] The NYISO is also working to implement price sensitive zonal load bids in the day-ahead market, so that the amount of energy purchased by a LSE within a zone can be tied to the day-ahead zonal price. Price capped load zone bids are expected to be implemented during 2001. At present, non-LSEs cannot submit any form of load bid at internal NYISO load zones or buses. Any entity, however, can submit price sensitive load bids at the external proxy buses.

All generators that are installed capacity resources in New York are required to either bid into the day-ahead energy market, be scheduled in a day-ahead bilateral transaction to

[10] At the time of the NYISO start-up, it was unable to accommodate all requests from LSEs to submit nodal price sensitive demand bids. This capability has gradually been expanded, but will likely be subject to limits until late 2001.

serve load in the New York Control Area or be unavailable due to maintenance, forced outage or temperature derating.

There is currently a $1000/MWh bid cap for energy in New York that is expected to continue for the immediate future. Day-ahead bid caps also apply to some generating units to mitigate market power. There are FERC-approved caps on the bids of certain plants located within New York City that have been divested by Consolidated Edison. These bid caps apply when certain congestion patterns exist, and the applicability of these bid caps is determined in an initial step in the SCUC software, as discussed in subsection 5 below. There is also currently a $2.52/MWh bid cap on availability bid offers for 10-minute non-spinning reserves to mitigate market power in the 10-minute reserve market.

All bids internal to New York must be associated with specific generators or loads. "Virtual bids" that are used only for determining financial obligations and settlements are not currently accommodated. The NYISO and its committees are working on a methodology to accommodate virtual bidding within New York.

4. Transmission Service

Market participants may serve internal or external loads by purchasing transmission service and scheduling bilateral transactions rather than buying and selling energy in the ISO-coordinated markets. This transmission service may be scheduled in the day-ahead (SCUC) or hour-ahead (BME) markets between locations within New York, or between New York and external proxy buses for service into, out of, or through New York.

a) Requests for Transmission Service

Transmission customers request transmission access day-ahead by submitting a bilateral schedule to the ISO. They do not need a physical transmission reservation or any type of physical transmission right in order submit such a schedule or to obtain transmission service. The NYISO offers both firm and non-firm transmission service. Customers requesting firm service agree to pay the congestion charges associated with their scheduled service. Non-firm service is available for customers that do not want the ISO to schedule their transaction if it would require payment of a congestion charge.

b) Format of a Bilateral Bid/Schedule

All requests for transmission service consist of an hourly bilateral schedule, in MW, as well as an hourly decremental bid for the generator supplying the bilateral transaction. The SCUC software treats the decremental bid associated with a bilateral schedule identically to other generator bids in the energy market, so that a bilateral generator may be dispatched so that its day-ahead energy schedule falls below its bilateral schedule. When this occurs, the billing process records a compensating purchase from the LBMP energy market to balance the bilateral transaction.[11] Thus, the decremental bidding provisions of the NYISO Tariff provide the opportunity for generators participating in a bilateral transaction to buy energy from the LBMP market if this is cheaper than generating to meet their bilateral commitment. This opportunity is available to all generators participating in bilateral transactions, both internal and external to New York, except those undertaking wheel-through transactions.

The decremental bids of bilateral transactions sourced from internal generation are determined directly from the generator's incremental energy bid curve. If the bilateral transaction is at a level on the bid curve where the incremental energy bid is not defined, e.g., below its minimum generation level, a default bid of -$100/MWh is used as the decremental bid. Bilateral transactions sourced from external locations are required to enter a decremental bid when submitting schedules to the NYISO. By submitting a large negative bid, the bilateral party can ensure that the generator schedule will not be modified, except under extreme circumstances. A negative decremental bid can result in a large charge for congestion in the event that it is accepted, so that there are financial consequences to submitting such a bid. This provides an incentive for generators to

[11] The discussion applies to generators that are on dispatch and have signed the ISO Services Tariff. If the bilateral transmission customer has not signed the ISO Services Tariff, then the charge for replacement energy is the greater of 150% of the day-ahead LBMP or $100/MWh. (Sheet No. 173 of Services Tariff.)

provide realistic decremental bids, including bids for counter-flow. In turn, it allows the NYISO to manage congestion in the day-ahead market on a market basis in most cases using bids, rather than with other, non-market means.

External transactions between New York and other control areas must submit NERC tag information, in accordance with NERC Policy 3. Market participants must submit NERC tags following the posting of schedules for accepted transactions.

c) Obtaining a Transmission Schedule

The NYISO generally accepts firm bilateral schedules for the full amount of the transmission service requested day ahead, with the exception of requests for wheeling service through New York.[12] In order to accommodate as many firm transmission service requests as physically possible, the NYISO SCUC will dispatch internal and external generators and loads based on their bids, including the dispatch of counter-flow transactions when economic. This dispatch takes account of bids into the energy market as well as decremental bids of generators supporting firm bilateral transactions. Non-firm bilateral transactions are not considered at all in the day-ahead unit commitment or dispatch. Advisory schedules are provided after the day-ahead unit commitment, and are updated after the BME.[13]

d) Transmission Congestion Contracts

Transmission service under the NYISO is made available on a long-term fixed-price basis through the auction of Transmission Congestion Contracts ("TCCs"). TCCs are financial transmission rights that, under the new market structure, can be used to hedge day-ahead congestion costs incurred for a bilateral contract. As described in subsection 6 below, a

[12] For wheels through New York, the amount of transmission service scheduled day ahead is based on the physical amount of energy scheduled from the external generator that is party to the transaction. If the schedule of the external generator is modified based on its decremental bid, then the bilateral schedule is also modified to match the generator schedule.
[13] Non-firm transactions that are accepted in the BME then flow unless congestion occurs and they are cut in the real-time dispatch.

party that schedules transmission service for a bilateral contract will pay a Transmission Usage Charge ("TUC"), which includes a charge for transmission congestion. Market participants can lock in their congestion-related costs in advance between a point of injection and a point of withdrawal by purchasing TCCs to offset this payment for congestion.

TCCs are denominated in units of 1 MW and specify a point of injection, a point of withdrawal, and a duration over which the TCC is in effect. The injection and withdrawal points may be any locations at which the NYISO calculates a price; these include generator buses, load zones, external proxy buses, and a limited number of load buses.

TCCs have been allocated in New York through a series of steps in order to address a number of objectives: to preserve, financially, transmission rights established by grandfathered pre-ISO transmission agreements; to preserve, financially, the rights of native loads; and to make as many TCCs available to the market as possible to enhance liquidity and trading. TCCs were allocated, first, to parties with grandfathered pre-ISO transmission agreements. All remaining transmission capacity has been sold as TCCs through periodic auctions. Existing TCCs may also be released for sale through the auctions. TCCs valid for a period commencing with the start-up of the NYISO and ending on April 30, 2000 were sold in the initial TCC auction in September 1999. In the spring of 2000 auction, 35% of available system transfer capability was sold as 2-year TCCs and 65% was sold as 6-month TCCs. In the autumn 2000 auction, 23% of available system transfer capability was sold as 5-year TCCs, 23% as 2-year TCCs and 54% as 6-month TCCs. In June, 2000 the NYISO also began monthly reconfiguration auctions for TCCs.

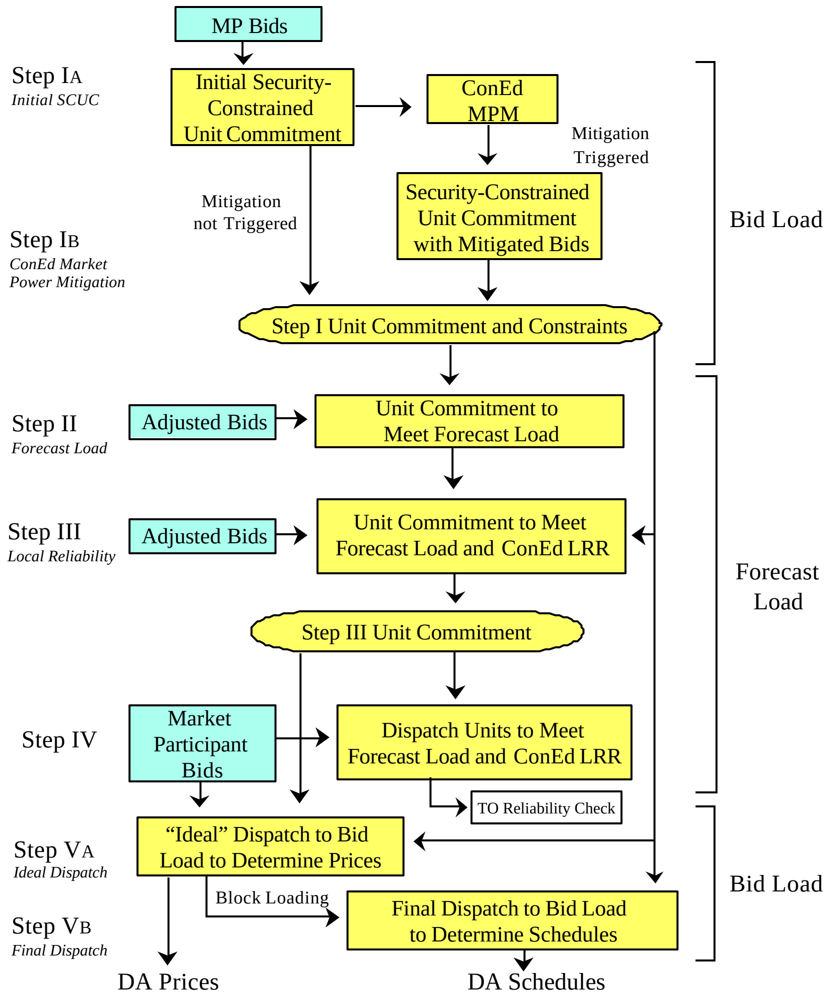
TCCs do not confer any physical scheduling or curtailment priority. They are financial instruments that establish a right to collect, or an obligation to pay, congestion costs in the day-ahead market for energy associated with a single MW of transmission between a designated point of injection and a designated point of withdrawal.

5. Software Description

The New York day-ahead market is run using a unit commitment and dispatch program that is usually called SCUC. SCUC is structured in a series of steps in order to implement FERC-approved market power mitigation programs, allocate the costs associated with local reliability rules, and ensure the NYISO's ability to meet forecast load.

The structure of the NYISO SCUC program is portrayed in Figure 1. The first step in the SCUC program, called IA in Figure 1, is the Con-Ed market power mitigation step. The purpose of this step is essentially to determine if the bid caps approved by FERC for certain units divested by Con-Ed will be applied in the day-ahead market. In order to determine this, the program fully solves the security constrained unit commitment problem, iterating to a secure solution for all transmission constraints (other than Con-Ed local reliability rules), scheduling ancillary services to meet the locational requirements, dispatching internal and external generation to meet internal and external bid-in load, and calculating locational prices. This step takes 15-30 minutes to complete.

Figure 1
Structure of NYISO SCUC Program



If the generator bus price calculated in Step IA for a generator that is subject to the Con-Ed market power mitigation exceeds 105% of the generator bus price calculated for Indian Point 2 in any hour of the day,[14] then the energy bid component of the Con-Ed market power mitigation will be triggered for that generator for all hours of the day. The incremental energy bids submitted by the units subject to the Con-Ed market power mitigation are replaced within SCUC by pre-determined mitigated bids, unless the original energy bids were lower, and SCUC starts over in Step IB using the lower of the original or mitigated energy bids. Step IB then fully repeats the process of iterating to a secure solution for all transmission constraints (other than Con-Ed local reliability rules),

[14] This condition will normally be triggered if there are binding transmission constraints between New York City and the East of Central East region, but will not be triggered if the Central East constraint alone is binding.

scheduling ancillary services to meet the locational requirements, dispatching internal and external generation to meet internal and external bid-in load, and calculating locational prices. This step generally runs slightly faster than the 15-30 minutes required for Step IA, because the iteration process is able to start closer to the optimal solution.

At the end of Step IB, or Step IA if the Con-Ed mitigation is not triggered, SCUC proceeds to Step II, which is also a unit commitment step. The purpose of this step is to ensure that sufficient resources are available to meet the NYISO's forecast load, as well as the bid-in load scheduled in Step I. Step II starts with the unit commitment determined in Step I, and the constraint set from Step I (the constraint set includes all of the constraints identified in the course of iterating to the solution in Step I). In addition, all units committed in the Step I solution remain committed in Step II. Step II therefore does not entail a complete iterative solution of the unit commitment problem, but iterates from the Step I solution to a secure solution meeting forecast load while respecting all transmission constraints (other than Con-Ed local reliability rules), scheduling ancillary services to meet the locational requirements, and dispatching internal and external generation to meet internal forecast load and external bid-in load. This step also has a series of specialized conventions regarding the incremental energy bids and start-up costs that are minimized in the commitment and dispatch. The effect of these conventions is to ensure that SCUC minimizes the sunk cost of committing sufficient additional resources for the NYISO to reliably meet forecast load in excess of bid-in load. It should be noted that the Step II solution is not used in any manner in the unit commitment and dispatch process. The only significance of the Step II solution is for cost allocation, since uplift is allocated differently for units committed in Step III but not in Step II, than for units committed in both Steps II and III.

Step III is the local reliability unit commitment step. Step III is analogous to Step II in that it starts with the unit commitment determined in Step I and the constraint set from Step I (the constraint set includes all of the constraints identified in the course of iterating to the solution in Step I). In addition, all units committed in the Step I solution remain committed in Step III. Step III therefore does not entail a complete iterative solution of the unit commitment problem, but iterates from the Step I solution to a secure solution meeting forecast load while respecting all transmission constraints, including finally, the Con-Ed local reliability rules, scheduling ancillary services to meet the locational requirements, and dispatching internal and external generation to meet internal forecast load and external bid-in load. Like Step II, Step III has a series of specialized conventions regarding the incremental energy bids and start-up costs that are minimized in the commitment and dispatch. The effect of these conventions is to ensure that SCUC minimizes the sunk cost of committing sufficient additional resources for the NYISO to reliably meet forecast load in excess of bid-in load.

Step IV is a dispatch step rather than a unit commitment step. In Step IV, the unit commitment is fixed at the Step III solution and these units are dispatched to meet forecast load while enforcing local reliability rules. This step differs from Step III in that actual incremental energy bids are used for the dispatch, as opposed to bids that have been modified to implement a dispatch that minimizes sunk costs. The solution to this step is provided to transmission owners for their review of the line loadings and other reliability information for the following day.

Step V is also a dispatch step. Step VA, the ideal dispatch, is used to calculate prices, and Step VB, the final dispatch, is used to determine schedules. In Step VA all non-quick start internal units committed in Step III are treated as on at minimum, and quick start units, external loads, internal loads and external supplies are treated as dispatchable, along with the incremental energy blocks of the units committed at minimum, and are dispatched to meet bid-in load. Step VB is the schedule determination step, and differs from Step VA in four respects. First, any GT dispatched above zero in Step VA is blocked on to its full output in Step VB. Second, any external supply bid accepted in Step III is blocked on to the Step III output in Step VB. Third, any external demand bid accepted in Step VA is blocked on to the Step VA output in Step VB. Fourth, any GTs selected for energy at the end of Step I are blocked on to full output. The remaining internal generators are then dispatched to meet bid-in load. The results of this dispatch determine the final day-ahead schedules.

Important elements of the SCUC solution process as it relates to inter-control area transactions are:

- SCUC enforces the NYISO hour-to-hour ramping limit on total changes in external schedules;
- SCUC enforces both internal and inter-control area constraints in dispatching external transactions and loads;
- Internal generation will be redispatched to accommodate the impact of import/export schedules on internal transmission constraints;
- SCUC will schedule counter-flow transactions to accommodate both import and export schedules;
- SCUC may schedule transactions in the forecast load or local reliability steps (Steps II and III) that are not economic based on their bids and the settlement prices calculated in Step VA. These transactions receive a production cost guarantee, i.e. they are paid their bid.

6. Day-Ahead Pricing and Settlements

The NYISO uses LBMP to price energy purchases and sales in the day-ahead market and to price transmission usage scheduled in the day-ahead market. Energy transactions scheduled in the NYISO day-ahead market are settled based on the LBMP prices calculated in the price calculation step of the SCUC (Step VA). The locational prices take account of transmission congestion, the cost of marginal losses, and, in certain circumstances, the impact on the cost of providing reserves of dispatching generation to meet load. There are currently no price caps in New York, although there are bid caps for energy and 10-minute spinning reserves.

Energy sales by internal generators are settled at the LBMP price at the generator's location. Energy purchases by internal NYISO loads are settled at the zonal LBMP that applies at the load's location, unless the load has submitted a nodal price sensitive demand bid.[15] Energy purchases and sales by external suppliers and consumers are settled at the proxy bus price for the external control area. At present there is a single proxy bus for pricing all transactions with each adjacent control area.

Transmission usage scheduled in the NYISO day-ahead market is settled based on the difference in LBMP prices between the point of withdrawal and the point of injection. This is known as the Transmission Usage Charge ("TUC"). If there is no transmission congestion, TUC will be equal to the cost of incremental losses attributable to the incremental transmission usage.

Reserve prices are determined based on the highest availability bid accepted in the day-ahead market for capacity providing a given category of reserves. Although the NYISO's scheduling of reserves in SCUC is governed by locational reserve requirements for 10-minute spinning, 10-minute and 30-minute reserves, FERC did not accept the NYISO's September filing for locational pricing of reserves. In consequence of this and other FERC actions, LIPA has absolutely unmitigated market power in 10-minute spinning reserves, and at times in 30-minute reserves (because LIPA is the only supplier capable of meeting the Long Island reserve requirement). There is currently a $2.52/MWh bid cap on availability bid offers for 10-minute non-spinning reserves to mitigate market power in the 10-minute reserve market.

The NYISO reserve pricing system recognizes that capacity providing 10-minute spinning reserves is also providing 10-minute reserves and 30-minute reserves, and that 10-minute reserves are also providing 30-minute reserves. The day-ahead availability price of 10-minute spinning reserves will therefore never be lower than the day-ahead price of 10-minute or 30-minute reserves, and the day-ahead price of 10-minute reserves will never be lower than the price of 30-minute reserves. This pricing system is

[15] An eventual transition to nodal specific pricing for loads is envisioned, but there is no current timetable for this transition. See January 27, 1999 FERC order at: http://www.nyiso.com/services/documents/iso/f_012799.pdf

sometimes referred to as cascading. Generators providing 10-minute reserves in real time are also paid their real-time opportunity costs.[16]

The price of regulation in the day-ahead market is also set by the highest accepted availability bid and there are no payments for opportunity costs.

The cost of ancillary services is allocated uniformly to real-time load, including the cost of locational reserve requirements.[17] Generation or external supply that fails to recover its as-bid costs at the prices calculated in Step VA of SCUC receives a production cost guarantee that ensures that it recovers its as bid costs.[18] The cost of production cost guarantees to units committed in Step III of SCUC, i.e. for local reliability, is allocated to loads in the Con-Ed service territory. All other uplift is allocated to all real-time loads, internal and external.

7. Day-Ahead/Real-Time Coordination

a) Timeline

The New York markets currently operate according to the following schedule:

- 5:00 a.m.– Deadline for submitting bids and schedules for the day-ahead market.
- 11:00 a.m. – SCUC is completed. LBMPs are posted on the Bid/Post System as public data and commitment schedules are posted on the Bid/Post System as private data. SCUC is usually completed prior to 10:00 a.m.

[16] Opportunity costs arise on 10-minute reserves because NYISO dispatch procedures maintain reserves on 10-minute units while dispatching higher cost units to meet load. This is not the case for units providing 30-minute reserves. Units providing 30-minute spinning reserves are dispatched to meet load in real time without regard to their reserve status, so that reserves would not be scheduled on 30-minute GTs if it required the dispatch of higher cost on-line capacity. Capacity providing 30-minute reserves therefore should not incur real-time opportunity costs.

[17] The costs of operating reserve are allocated to real-time load in the NYCA and scheduled exports on a per MWh basis.

[18] In addition, uplift may be paid to external supply (or load) if it is scheduled in BME and faces a real-time settlement price that is less than (greater than) its bid.

- 90 minutes prior to the start of the hour – Deadline for submitting bids and schedule changes to BME.
- 60 minutes prior to the start of the operating hour – The results of the BME are posted on the Bid/Post System as the schedule for the upcoming operating hour.
- 30 minutes prior to the start of the operating hour – NYISO checks out its schedule for inter-change transactions with adjacent control areas. Transactions that fail checkout are eliminated from the schedules for the following hour and compensating adjustments are made as required.

b) Hour-Ahead Bidding and Scheduling Procedures

The balancing market evaluation, or BME, is the NYISO name for the process in which hour-ahead schedules are determined, providing a critical link between the day-ahead schedules and real-time dispatch.[19] Similar reliability functions are performed by every control area, each of which has an hour-ahead process for scheduling transactions with adjacent control areas, evaluating reserves and taking actions to maintain operating reserves for the next hour. In New York these functions have been automated and based on objective criteria and bids, creating BME. In addition, the New York BME allows market participants that are available for dispatch in real time to submit changes to their hour-ahead bids through the BME bid process, and market participants that are not on economic dispatch through SCD have the option of having their hourly schedules adjusted in BME.[20]

The NYISO uses BME to establish schedules for each hour of the dispatch day. Transactions scheduled day-ahead and bids and schedules submitted subsequent to the closing of the day-ahead market are evaluated to assure that transmission limits are respected. External transactions are also evaluated in BME against their decremental bids (for import transactions) or sink cap bids (for export transactions). BME establishes

[19] The BME is sometimes also referred to as the HAM or hour-ahead market.
[20] It is important to recognize that market participants who do not want BME to adjust the schedules of their off-dispatch units are able to set their own schedule and avoid adjustment in BME by submitting low decremental bids and high incremental bids.

the hourly schedules for external transactions that are used to set the desired net interchange with neighboring control areas.

BME operates as a market-based evaluation in three important respects. First, if transmission congestion on constraints within**,** into or out of New York are binding, transmission usage will be allocated based on bids. Second, if the NYISO needs to import additional energy from adjacent control areas in order to meet load or maintain targeted reserve levels, these purchases will be made on a least-cost basis using the bids submitted to BME.[21] Third, if the NYISO needs to schedule counter-flow in order to maintain day-ahead transmission schedules, this counter-flow will be scheduled based on the bids submitted to BME.

At the start-up of the NYISO, the pricing rules for transactions scheduled in BME were inconsistent with the BME scheduling rules during BME periods in which imports or exports were limited by external interface or ramping (DNI) constraints.[22] This inconsistency affected market participant bidding incentives, created financial risks for external transactions scheduled in the day-ahead market, and made it uneconomic for market participants to offer counter-flow transactions to relieve congestion on external interfaces.

The NYISO initially addressed the inconsistency between pricing rules and scheduling rules during BME periods in which imports or exports are limited by external interface or ramping (DNI) constraints by in effect turning day-ahead schedules into physical rights in

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[21] The other action that may be taken in BME to meet load or to maintain 10-minute reserves would be to start 30-minute GTs.

[22] The potential for inconsistency arose because there are a number of transmission and interchange constraints modeled in BME that are not affected by the dispatch of any internal New York generator, and thus cannot affect the real-time prices determined in SCD. (SCD is the real-time security-constrained dispatch program that is currently used by the NYISO to dispatch generation in real time and calculate real-time LBMPs.) When these constraints are binding in BME, the market-clearing bid in BME will likely be unrelated to real-time prices, because the market-clearing bid in BME will reflect the impact of binding constraints not taken into account in calculating real-time prices. This inconsistency between BME and SCD in turn gave rise to an inconsistency between BME schedules and settlement prices because settlement prices for external transactions scheduled in BME, as well as for deviations from day-ahead schedules, were originally based on real-time prices as calculated by SCD.

the hour-ahead market.[23] This approach gave rise to difficulties that led the NYISO to implement ECA "B," which brings the settlement prices for external transactions in line with the BME scheduling criteria during periods in which there is congestion in BME on the external transmission constraints.[24] ECA "B" is modeled on a similar provision in the NEPOOL tariff filed with FERC on March 31, 2000 and approved on June 28, 2000.

Under ECA "B," BME bids can determine real-time settlement prices at the external proxy buses in hours in which external interface or DNI constraints are binding. Thus, if imports into New York are limited by an external interface constraint or a DNI constraint, then real-time settlement prices at the affected external proxy buses will be the lower of the market-clearing price in BME at that proxy bus or the real-time price in SCD at that external proxy bus. Conversely, if exports from New York are limited by an external interface constraint or a DNI constraint, then real-time settlement prices at the affected external proxy bus will be the higher of the market-clearing price in BME at that external proxy bus or the real-time price in SCD at that external proxy bus.

c) Transaction Checkout

Transactions scheduled in BME may fail to flow in real time either because of real-time reliability curtailments or as a result of failing checkout. The checkout process is the procedure by which the receiving and sending control area operators communicate roughly one-half hour before real time and agree on the net interchange that will be maintained between the control areas for the next hour. One purpose of this process is for the control areas to confirm that each control area has the same list of transactions between the control areas. For each transaction delivering power out of a control area there should be another transaction receiving that power into the receiving control area.

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[23] This was implemented by subtracting $20,000 from the day-ahead bids of import transactions scheduled in the day-ahead market, adding $20,000 to the day-ahead bids of export transactions scheduled in the day-ahead market, and subtracting $20,000 from the day-ahead congestion bids of wheel-through transactions scheduled in the day-ahead market.

[24] ECA "B" originally became effective October 11, 2000, and was reissued as ECA 20001218B. See, http://mis.nyiso.com/public/postings/Real%20Time%20External%20Proxy%20Bus%20Prices%20ECA20001006B.PDF and http://mis.nyiso.com/public/postings/ecac20001208b.pdf.

Transactions scheduled in BME will not flow in real time if they "fail checkout," meaning that the other control area involved in the transaction does not have a record of a matching transaction or the size of the transaction scheduled differs between the control areas. Moreover, the failure of a particular transaction to check out can have secondary effects that require additional transactions to be cut.[25]

In the course of the summer of 2000, it became apparent to the NYISO, as well as to the other Northeastern ISOs, that a very high rate of transaction failure during checkout was developing. While occasional data mistakes by market participants and ISO staff will inevitably occur, the pattern of the checkout failures, particularly the frequency with which only one control area had any record of a transaction, suggested that a deliberate effort was being undertaken to manipulate prices in the New York, PJM or NEPOOL markets by scheduling sham transactions.[26]

In view of the potential serious consequences for reliability of the high frequency with which these sham transactions were failing checkout, as well as the impact on the cost of meeting load and real-time market prices, the NYISO implemented ECA "A" to deter the deliberate scheduling of sham transactions.[27] ECA "A" provides that transactions scheduled in BME for the delivery of energy into New York for which no energy is delivered in real time will be settled by the scheduling entity buying energy to cover the shortfall at the real-time spot price at the external proxy bus and selling that energy back at the scheduling entity's BME bid price.[28] Conversely, transactions scheduled in BME for the delivery of energy from New York to another control area for which no energy is delivered in real time will be settled by the scheduling entity selling the energy that was

[25] This could occur for example, if the elimination of a transaction that failed checkout caused the remaining schedules to violate a transmission or DNI constraint.
[26] The scheduling of sham import transactions that will fail checkout can be used to elevate real-time prices in a market by backing out other import transactions or deterring the ISO from starting 30-minute GTs. The scheduling of sham export transactions can conversely depress real-time prices by blocking other exports or causing 30-minute GTs to be started.
[27] ECA "A" was originally implemented effective September 8, 2000 in hour beginning 12:00, and was recently reissued as ECA 20001218A. See http://www.nyiso.com/topics/whats_new/eca_20000907a.pdf and http://mis.nyiso.com/public/postings/ecac20001208a.pdf
[28] No payment is required if the real-time price is lower than the bid price.

not taken at the real-time spot price at the external proxy bus and buying that energy back at the scheduling entity's BME bid price.[29] No payments are required if the transaction was properly scheduled and failed to flow as a result of actions taken by the NYISO or the other control area operator. ECA "A" appeared to promptly change the scheduling behavior that was causing so many transactions scheduled in BME to fail check out.

B. New England – ISO

The ISO New England Inc. ("ISO-NE") was established as a non-profit, private corporation on July 1, 1997. ISO-NE is responsible for operating New England's electric bulk power system and for administering the region's restructured wholesale electricity markets. Prior to ISO-NE's formation, the New England Power Pool ("NEPOOL"), a voluntary association of New England utilities, operated the region's bulk power generating and transmission facilities for 27 years.

On May 1, 1999, ISO-NE began to administer a wholesale marketplace for energy, automatic generation control, 10-minute spinning reserve, 10-minute non-spinning reserve, 30-minute operating reserve and operable capacity.[30] With the exception of operable capacity, these products are currently bought and sold daily, by the hour. Market participants bid their resources into the market the day before, submitting separate bids for each resource for each hour of the day.

On March 31, 2000 the ISO-NE submitted a Section 206 filing to the FERC to implement a congestion management system ("CMS") and multi-settlement system ("MSS") in the New England control area. The filing was conditionally accepted by the FERC on June 28, 2000. The new systems will provide a market structure in New England that is very similar to those in place in PJM and New York. Under the new CMS/MSS, the ISO-NE will operate a two-settlement system in which energy transactions and transmission usage are settled using locational prices. NEPOOL's current single settlement market will be

[29] No payment is required if the real-time price is higher than the bid price.
[30] The market for operable capacity was eliminated on March 31, 2000.

replaced by two markets: a day-ahead market that results in a financially binding schedule for the following dispatch day and a real-time market used to settle real-time transactions and differences between day-ahead schedules and real-time generation and load. NEPOOL will also move from its current uniform pricing system to a system of locational prices for managing congestion. Like New York and PJM, NEPOOL will implement a system of financial transmission rights for hedging congestion costs arising from its CMS system.

On December 1, 2000, ISO-NE filed an update indicating the dates at which it expects to be able to implement various components of CMS/MSS. The implementation plan is divided into two phases. Phase 1 will address CMS and significant improvements to the single-settlement system, including locational pricing, financial transmission rights, and a market approach to external transactions. Phase 1 will also include adoption of three-part generator bidding. At the time of the December filing, the ISO expected that Phase 1 would require, at a minimum, 15 to 17 months to implement. It plans to set a final schedule for Phase 1 by March 2001. Phase II includes some remaining components of CMS, principally permitting load to pay nodal prices, and the full implementation MSS. The ISO estimates that the earliest possible implementation date for Phase 2 will be 12 months after Phase 1.

The description of the New England day-ahead unit commitment and scheduling process below will focus on the marketplace after the start-up of the new CMS/MSS system. This is appropriate given the objective of the present study to identify long-term solutions to improving the regional day-ahead market in the Northeast.

1. Overview of the ISO-NE Day-Ahead Market

The ISO-NE will operate the day-ahead unit commitment and scheduling process under its multi-settlement system using software that performs a Security-Constrained Unit Commitment ("SCUC") based on the supply and demand bids of market participants. It is intended that the NEPOOL SCUC will simultaneously commit generation to meet energy, operating reserve and regulation requirements. The unit commitment will be based on bids from qualifying generation and loads to supply energy, 10-minute spinning reserves, 10-minute non-spinning reserves, 30-minute reserves, four-hour reserves and regulation. Suppliers and customers external to New England may submit energy bids at external buses located in neighboring control areas. Unlike New York, NEPOOL participants will not schedule physical bilateral transactions in the day-ahead market; bilateral schedules will be purely financial and will not enter into the SCUC process.[31] SCUC will minimize the as-bid cost of serving load whose demand clears in the day-ahead market and of ensuring that sufficient generation is committed or available to meet forecast load, reserve and regulation requirements. The unit commitment will be performed using a complete model of the NEPOOL transmission system and will reflect transmission constraints based on the expected grid configuration. Thus, both transmission congestion and losses will be taken into account in the selection of accepted bids. The commitment of generation to meet energy and operating reserve requirements will be location specific, allowing the ISO-NE to evaluate security requirements for both transmission and generation contingencies.

The SCUC will produce energy, regulation and reserve schedules, including start-up times and operating levels, for generators and loads for each of the 24 hours of the dispatch day. It will also produce day-ahead prices for energy and ancillary services. The hourly locational prices will be calculated for each generator location within NEPOOL, load zones, and external buses in the regions bordering NEPOOL, including New York, HydroQuebec, and New Brunswick.

Day-ahead financial settlements will be calculated based on the hourly day-ahead market-clearing prices and schedules. Energy market settlements will be calculated based on the day-ahead locational energy prices and generator and load energy schedules. ISO-NE will also facilitate bilateral contracts between market participants by adjusting the energy market settlement obligations between the ISO-NE and the supplier and customer to

[31] OATT customers that are not NEPOOL participants may take Through, Out or Internal Point-to-Point Service. The mechanisms for implementing this are still somewhat in flux.

reflect energy transferred under the bilateral contract.[32] Day-ahead settlements for reserves and regulation will be based on the market-clearing price, which will be determined based on availability bids and lost opportunity costs. Generators that are scheduled day ahead may also receive additional make-whole payments, as in New York and PJM, if the sum of their day-ahead energy and ancillary services revenue falls short of the as-bid cost of their day-ahead schedule.

2. Products

The ISO-NE day-ahead unit commitment and scheduling process will produce prices and settlements for six products: energy, 10-minute spinning reserves, 10-minute reserves, 30-minute reserves, automatic generation control ("AGC" or regulation), and under certain circumstances, four-hour reserves. The category of 10-minute reserves includes both 10-minute spinning reserves and 10-minute non-spinning reserves, which can be used interchangeably to meet the 10-minute reserve requirement. The category of 30-minute reserves includes 10-minute spinning reserves, 10-minute non-spinning reserves, 30-minute spinning reserves and 30-minute non-spinning reserves, all of which can be used interchangeably to meet the total 30-minute reserve target.[33] Four-hour reserves, which are a new product introduced in the CMS/MSS filing, are scheduled to meet the ISO forecast load in excess of load bids cleared day ahead, like FRED in New York.[34]

As noted above, the products under the March 31, 2000 NEPOOL tariff correspond closely to those in the existing New York ISO tariff. The main exception is that the ISO-NE tariff establishes a category called four-hour reserves and provides for payments to generators providing four-hour reserves. It is also similar to Ontario in that it establishes markets for 10-minute spinning reserves, 10-minute non-spinning reserves and 30-minute

[32] An exception is made for OATT customers that are not NEPOOL participants and that take Through, Out or Internal Point-to-Point Service, who pay a charge for congestion and marginal losses that is equal to the difference in the locational prices at the injection and withdrawal points for the transaction.

[33] Because of these relationships between the operating reserve categories, the products that are priced in the market: 10-minute spinning reserves, 10-minute reserves and 30-minute reserves do not correspond to the products for which market participants bid: 10-minute spinning reserves, 10-minute non-spinning reserves and 30-minute reserves.

[34] Other operating reserves may be substituted for four-hour reserves if the cost is less.

reserves, which are separately priced and co-optimized with the energy dispatch. It has in common with PJM four market-based ancillary services – 10-minute spin, 10-minute non-spin, 30-minute reserves and regulation, albeit there are significant differences in the market mechanisms.

3. Bidding into the Day-Ahead Market

The day-ahead unit commitment and scheduling process in New England will be based on supply bids from generating units, dispatchable loads (including interruptible export sales) and market participants who wish to import energy into NEPOOL, and demand bids from market participants serving load. All supply bids internal to NEPOOL must be associated with specific generators. Virtual supply offers from external resources are permitted. Virtual demand bids are permitted both within and outside of NEPOOL. Demand bids may be submitted at any location by any market participant, including all LSEs within NEPOOL and participants that wish to export energy from NEPOOL. The ISO-NE will monitor the market to determine whether the virtual demand bids create gaming opportunities or give rise to persistent inconsistencies between day-ahead and real-time prices.

All generating units and dispatchable loads may submit availability bids for AGC, 10-minute spinning, 10-minute non-spinning, 30-minute reserves and four-hour reserves as part of their supply offer.[35]

As in PJM and New York, NEPOOL will implement multi-part energy bidding (called a "three-part price system") for generators in the day-ahead unit commitment and scheduling process. The three-part energy price bids in NEPOOL include a start-up price, an hourly no-load price (for the minimum load energy block) and incremental energy

[35] In addition to receiving supply offers for reserves in the day-ahead market, the ISO-NE is also authorized to work out market rules to establish forward markets for reserves.

prices. Both the no-load price and incremental energy price may vary by hour.[36] This bid structure allows a unit to bid its marginal cost for its entire operating range and to still be assured that it will recover its as-bid cost, regardless of its final schedule. Generators may, alternatively, provide single-part bids, if they so choose. The point of injection for generator bids is a specific bus on the ISO-modeled transmission system.

Bids for incremental energy must be monotonically increasing. This means that the bid for an increased amount of energy must be equal or higher than the per unit bid for a lesser quantity. Price sensitive demand bids for energy must, similarly, be monotonically decreasing.

CMS/MSS will treat external transactions in large part identically to internal NEPOOL generation and load.[37] External suppliers that wish to schedule an import transaction submit a supply bid at the external node for the control area from which they will export the energy.[38] Similarly, a market participant scheduling an export from NEPOOL will submit a demand bid at the external node for the control area to which it wishes to deliver energy. External suppliers will not be eligible to supply operating reserves or four-hour reserves until control area operations address certain technical problems, including dynamic scheduling, and there are appropriate changes to the market rules.

Under CMS/MSS, generating resources will be able to self-schedule, if the self-schedule is feasible given transmission constraints.[39] This is a continuation of the current NEPOOL market rules, under which market participants may instruct the ISO at what levels to run their resources, and is consistent with the provision for self-scheduling in PJM and New York. Moreover, under the new bidding rules market participants may

[36] There will likely be some limits on changes in start-up and minimum load bids under the transitional CMS (prior to full MSS implementation), but these limitations would be removed when MSS implementation is complete.
[37] Import transactions from HydroQuebec retain certain features reflecting the scheduling and settlement provisions of pre-existing contracts. Further, external suppliers will not be able to bid minimum run times. It remains undetermined whether external suppliers will be able to bid start-up and no-load costs.
[38] An external node is defined as a bus or buses used for establishing a locational price for energy received by participants from, or delivered by participants to, a neighboring control area.
[39] FERC has granted a rehearing on this issue.

submit bids that will ensure that their resources operate absent transmission contingencies and emergency situations.[40]

There is currently a $1000 bid cap in the New England energy market. The ISO may implement mitigation under Rule 17 when it is determined that the pattern of a market participant's bids and/or operation appears to be inconsistent with a competitive market. Under Rule 17, the ISO currently has the ability to mitigate any market participant in each of the NEPOOL markets for energy, AGC, 10-minute spinning reserve, 10-minute non-spinning reserve, 30-minute operating reserve and installed capacity, to ensure competitive market operations and system reliability. Uncompetitive behavior includes the physical and economic withholding of generation with the intent to raise the market-clearing price or to affect uplift payments. While the purpose of Rule 17 will remain the same under CMS/MSS, the specific implementation measures are expected to change.

Load-serving entities can submit price sensitive bids for the MWs of energy they wish to purchase in the day-ahead market in each load zone. The allocation of this load across buses will be governed by allocation factors determined by ISO-NE.[41] In addition, any entity can submit price sensitive load bids at the external proxy buses.

4. Transmission Service

The CMS/MSS market structure will eliminate "In Service" requirements for transmission reservations and scheduling. In Service was designed to manage the allocation of transmission for import transactions. However, it has proved to be ineffective because transmission customers are not charged for reserving the service and reserve more service than they need, creating problems of withholding.[42] As a result, some economic transactions are unable to schedule transmission service under the current

[40] Under CMS/MSS, generating units may choose to self-commit after the day-ahead unit commitment is run, unless the ISO identifies reliability problems associated with the request. If committed, units will not receive uplift or set the clearing price

[41] The June 28, 2000 FERC Order requires that load-serving entities have the option of submitting load bids at internal NEPOOL buses, and paying the locational price at that bus.

market system. Under CMS/MSS, use of the transmission system will be allocated based on market mechanisms, rather than with a system of transmission reservations.[43] Market participants that wish to import or export from the PTF (Pool Transmission Facilities) Transmission System will submit supply and demand bids at external nodes. These bids will be evaluated, along with all other supply and demand bids, in the day-ahead unit commitment and scheduling process. The bids that are accepted in the scheduling process determine access to transmission for import and export transactions. "Short Notice" transactions will continue under the CMS/MSS system, but their availability will also be based on bids.[44]

a) Financial Congestion Rights

Transmission service under CMS/MSS will be made available on a long-term fixed-price basis through the auction of Financial Congestion Rights ("FCRs"). FCRs are financial transmission rights that, like the FTRs in PJM and TCCs in New York, provide a hedge against congestion charges. Market participants can lock in their congestion-related costs in advance between a point of injection and a point of withdrawal by purchasing FCRs to offset payments for congestion. FCRs will be ultimately available as both obligations and options. In technical terms, obligations establish a right to collect, or an obligation to pay, congestion rents in the day-ahead market for energy associated with a single MW of transmission between a designated point of injection and a designated point of withdrawal. Options, on the other hand, do not require the holder to pay the ISO when congestion is in the opposite direction of the FCR.

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[42] A similar withholding problem has afflicted the scheduling of NEPOOL "Out Service" and would be eliminated under CMS/MSS, if not before.

[43] Wheel-through transactions may still need to secure a transmission reservation under the CMS/MSS system.

[44] Currently, Short Notice transactions can be denied if they would change the day-ahead unit commitment. For example, a Short Notice export could be denied if it would require the commitment of a unit that was not economically committed day ahead. That restriction will be dropped under CMS/MSS, and the scheduling of Short Notice transactions will be based on market participant bids.

As in New York and PJM, each FCR will specify an origin, a destination, a number of MW, and a time during which the FCR is in effect. The origin and destination of an FCR may be any location, including a node, a load zone, or the hub.

FCRs relating to the entire physical transmission capacity of the NEPOOL system will be sold in periodic auctions. FCR auctions will be held monthly for FCRs with a monthly term and biannually for FCRs with terms from six months to five years. FCRs not sold in biannual auctions and FCRs tendered for sale will be available for purchase in the monthly auctions. The holder of an FCR may sell it by submitting it to a subsequent auction or by selling it in a bilateral transaction.

FCRs are not physical transmission rights, and play no role in determining scheduling or curtailment priority. Early drafts of the CMS/MSS proposal described a role for FCRs as "tie-breakers" in the event that competing offers at a single node had the same price. This feature was not included in the final CMS/MSS filing at FERC.

5. Software Description

The objective of the day-ahead scheduling process is to meet bid-in load at least cost subject to meeting reliability requirements. Thus, the SCUC software will minimize the as-bid cost of serving load that has bid into the day-ahead market and of ensuring that sufficient generation is scheduled to meet forecast load, reserve and regulation requirements.[45] Other features of the software are expected to include:

- To ensure that the day-ahead schedule is physically feasible, the unit commitment will be performed using a complete model of the NEPOOL transmission system and will reflect transmission constraints based on the expected grid configuration. The commitment of generation to meet energy and operating reserve requirements will be

[45] The FERC did not approve the CMS/MSS proposal to implement demand curves for all ancillary services.

location specific, allowing ISO-NE to evaluate security requirements for both transmission and generation contingencies.

- Both transmission congestion and losses will be taken into account in the cost minimization and in the determination of accepted bids into SCUC.

- Supply and demand bids at external nodes will be scheduled and dispatched by SCUC on the same basis as bids at locations internal to NEPOOL.

- SCUC will minimize the as-bid cost of serving load and meeting reliability standards over a 24 hour day; it will not necessarily minimize the as-bid cost or clearing prices in any given hour.

- The commitment of generation to supply energy, AGC and operating reserves will be co-optimized to minimize the aggregate as-bid cost of the day-ahead schedule.

- The SCUC software will recognize that capacity bidding to provide 10-minute spinning reserves may also be used to provide 10-minute non-spinning reserves, 30-minute reserves, and four-hour reserves. Similarly, it will recognize that capacity bidding to provide other categories of reserves, such as 10-minute non-spinning reserves, may also be used to provide reserves of lower quality. By taking into account these relationships, the SCUC software will ensure that the prices for reserves are cascading. The day-ahead price of 10-minute spinning reserves will never be lower than the day-ahead price of 10-minute non-spinning, 30-minute or four-hour reserves. Similarly, the day-ahead price of 10-minute non-spinning reserves will never be lower than the price of 30-minute reserves or four-hour reserves.

- Four-hour reserves will be scheduled to minimize the availability cost of obtaining an option on the capacity day ahead, not the energy prices. The ISO-NE day-ahead unit commitment and dispatch program is still in the process of development so its structure cannot be described in detail or with certainty. In particular, it is not resolved whether algorithmically the scheduling of four-hour reserves will be best implemented by adding a separate forecast load step as in New York or scheduling, if possible, these reserves in a single step process. Nevertheless, it is anticipated that a separate forecast load step will be required in order to verify that the four-hour reserves can be dispatched to meet forecast load.

- Certain transmission constraints may require SCUC to schedule generating units with energy bids that are greater than the locational price. These units, called Reliability Must Run Generating Units ("RMR Units") may be scheduled to operate in the day-ahead unit commitment process to provide voltage support for localized areas, or to satisfy locational reserve requirements.

Important elements of the SCUC solution process as it relates to inter-control area transactions are expected to be:

- SCUC will enforce hour-to-hour ramping limits on total changes in external schedules;
- SCUC will enforce both internal and inter-control area constraints in dispatching external supply and demand offers;
- Internal generation will be redispatched to accommodate the impact of import/export schedules on internal transmission constraints;
- SCUC will schedule counter-flow transactions to accommodate both import and export schedules;

The unit commitment software will determine hourly schedules for the following dispatch day and hourly day-ahead prices for energy, AGC, operating reserves and, if required, four-hour reserves. The schedule for generating units, dispatchable loads and imports and exports from other control areas will meet the bid-in demand for energy at the relevant locational prices.

6. Day-Ahead Pricing and Settlements

As in New York, the ISO-NE will use a nodal/zonal pricing system to settle energy purchases and sales and transmission usage. The locational price of energy at each point on the system will include, in addition to the underlying as-bid cost of the energy, the marginal cost of transmission congestion and losses, and, in certain circumstances, the impact on the cost of providing reserves of dispatching generation to meet load.

Energy sales by internal generators will be paid the locational price at the node at which the resource is connected to the system. Physical NEPOOL loads may elect to be charged based on nodal prices, or on average prices for load zones, which generally correspond to reliability regions. The load zone prices for reliability regions will be the load-weighted average of the nodal prices within the region. The weights used to calculate this price will be based on actual hourly load at each node.[46] Energy purchases and sales by external suppliers and consumers will be settled based on the prices calculated at external nodes. These will be calculated on the same basis as internal prices, except that they will exclude the cost of non-PTF losses. All day-ahead prices, schedules and settlements will be determined hourly.

ISO-NE will support the settlement of bilateral contracts through accounting procedures that adjust the settlement obligations between the parties to the contract and the ISO. Bilateral contracts may relate to any of the product markets coordinated by the ISO. Bilateral energy trades can be priced at any location including a node, a load zone or a trading hub that will be established to facilitate trading. The hub is defined as a set of 32 buses in central Massachusetts. The hub price will be calculated as the weighted average of the 32 nodal prices, with equal weights.

The ISO settles day-ahead bilateral energy contracts by increasing the settlement obligation of the seller for the hour, and decreasing the settlement obligation of the purchaser, by the amount of energy specified in the contract. Participants pay day-ahead

[46] FERC has granted a rehearing on this issue.

prices for a positive settlement obligation at the locational price for energy at that location for that hour, and are paid for a negative settlement obligation.

OATT customers that are not participants in NEPOOL and that take Through, Out or Internal Point-to-Point Service pay a charge for congestion and marginal losses that is equal to the difference in the locational prices at the injection and withdrawal points for the transaction. This is identical to the TUC charge in New York. If there is no transmission congestion, transmission usage charges will be equal to the cost of incremental losses attributable to the incremental transmission usage.

Providers of ancillary services will be compensated based on a single market price for NEPOOL. This price will reflect the marginal cost of acquiring each ancillary service. Except where indicated, ancillary services costs are allocated to participants based on metered electrical load.

- Units providing 10-minute spinning reserves receive a price based on the availability bid and lost opportunity cost of the marginal unit that is scheduled to provide 10-minute spinning reserves.

- The market-clearing price paid to resources providing 10-minute non-spinning reserve and 30-minute reserves is determined from the availability bid and lost opportunity cost of the marginal unit that is scheduled to provide that category of reserves.

- Resources providing four-hour reserves, if required, are paid a price determined by the market-clearing availability bid. The cost of four-hour reserves is allocated to market participants who underbid their load in the day-ahead market and cause the need to schedule four-hour reserves.

- As described previously, pricing of reserves is cascaded, so that the price of a lower quality category of reserves will never exceed that of higher quality reserves.

- Generators providing AGC receive a price set by the market-clearing availability bid and lost opportunity cost for regulation.

Payments to reliability must run generating units are currently under reconsideration.

The day-ahead market in NEPOOL will include a "net supply offer shortfall" calculation to ensure that units that are committed to supply energy or ancillary services recover their as-bid costs. The unit commitment software takes into account start-up, no-load, incremental energy and AGC bids to determine which units will be committed and scheduled in the day-ahead market. However, prices are determined on a marginal basis, without regard to start-up and no-load prices. As a result, generating units that are part of the least bid-cost schedule may not fully recover their bid costs based on the market-clearing prices for energy, AGC and reserves. Under CMS/MSS, generating units may receive an uplift payment equal to the difference between their as-bid costs and their day-ahead revenue for energy and ancillary services. This payment is identical to the supplemental payments made to generators in New York and similar to the make-whole payments in PJM.

7. Day-Ahead/Real-Time Coordination

a) Timeline

All products are bought and sold daily, by the hour. This means that market participants bid their resources into the market the day before, submitting separate bids for each resource for each hour of the day.

Bidding and scheduling deadlines for the MSS are currently under development. Bids into the day-ahead market will be due by a "common deadline" during the day prior to the dispatch day. Under the MSS, generating units will be permitted to submit new bids for energy up until 90 minutes before the effective hour.[47, 48] They may increase the bid price for a unit, and may also decommit a unit.

C. Ontario IMO

1. Overview of the Ontario Market

At present, it is planned that the Independent Electricity Market Operator ("IMO") will begin operation of the Ontario market on an hour-ahead and real-time basis. Current plans also call for a day-ahead financial market, called the Energy Forward Market, to be implemented six months after the start-up of the real-time market. The energy forward market will be a non-locational day-ahead market for energy delivered within Ontario, unlike the locational day-ahead markets previously described for the NYISO and ISO-NE.

Ontario's real-time market will be based on offers and bids for incremental energy. Every five minutes the IMO will dispatch generators and loads based on their bids and offers and will determine a single unconstrained Market Clearing Price ("MCP") for Ontario. With a few exceptions, the 5-minute MCP and dispatch quantities will be used for 5-minute settlements with generators and loads. External schedules will be determined from an hour-ahead pre-dispatch program. They will be settled at the 5-minute MCP, adjusted for an hourly congestion charge between Ontario and the external zone that is calculated in the hour-ahead[49] pre-dispatch. The IMO will sell financial Transmission Rights ("FTRs") to hedge the congestion charge between Ontario and each external zone.

[47] CMS Phase 1 does not allow for generator rebidding, except for changes to self-schedules, which must be received at least 90 minutes before real time.
[48] ISO-NE currently enforces a 600MW per hour ramp restriction on the net interchange with other control areas. When the ramp rate will be exceeded, ISO-NE operators adjust transactions associated with the interfaces that contribute to the excess ramping condition.
[49] Hour-ahead pre-dispatch or the pre-dispatch as adjusted by the IMO closer to real time.

In addition to energy, there will be real-time markets for three types of operating reserves: 10-minute synchronized reserves, 10-minute non-synchronized reserves and 30-minute reserves.

Although Ontario's markets were scheduled to start in November 2000, the start date has been delayed. Testing of the markets is currently underway, and the new start date has tentatively been set for May 1, 2001, though no final decision has yet been made.

2. Day-Ahead Energy Forward Market

The IMO will operate a single day-ahead Energy Forward Market based on one-part bidding. Generation offers to sell into the day-ahead forward market will consist of an upward sloping one-part bid curve for incremental energy. Conversely, load bids to purchase from the market will consist of a downward sloping one-part bid curve. Offers and bids may differ for each hour of the dispatch day. Any market participant authorized as a financial market participant may submit offers and bids into the Energy Forward Market. Because market pricing is non-locational, generation bids will not be associated with a particular physical supply location, and load bids will not be associated with a particular physical withdrawal location.

Bids and offers into the energy forward market will be due the day before each dispatch day between 8:00 a.m. and 9:00 a.m. Following this, the energy forward market auction will be conducted at 9:15 a.m., and the market results will be posted by 9:30 a.m.

Offers to sell and bids to buy in the energy forward market will clear at a uniform Forward Market Clearing Price for Ontario for each hour of the dispatch day. The forward market-clearing price will be determined by stacking the hourly supply offers and the demand bids and identifying the point of intersection of the resulting supply and demand curves. Forward market quantities will be determined based on the accepted offers and bids for each market participant.

The day-ahead Energy Forward Market is purely a financial market and can be used to provide a settlement hedge for real-time transactions. It is not used to physically schedule the operation of the Ontario transmission system, or to determine schedules for Ontario's external interties.

Forward market quantities in the Energy Forward Market are settled like contracts for differences between the Forward Market Clearing Price and the Hourly Ontario Energy Price ("HOEP").[50] As an example of the forward market settlement accounting, suppose that a market participant load bid clears for 100 MW at a forward market-clearing price of $20. Similarly, suppose that a supply offer clears for 50 MW at the same forward market price. If the HOEP in Ontario is $15, the forward market settlement for the load will be 100 MW * ($20 – $15) = $500 payable to the IMO. Similarly, the IMO will pay the generator 50 MW * ($20 - $15) = $250.

These forward market settlements appear as separate line items on each market participant's settlement statement, and can be viewed as an adjustment to any settlements in the real-time market. Parties that participate in the real-time market may thus use the forward market to lock-in the price for their real-time injections and withdrawals. For example, if the previously described load actually consumed 100 MW in real time, its real-time settlement would be $100 * $15 = $1500 (assuming that it is non-dispatchable and pays the HOEP in real time). However, the sum of its real-time and forward market settlements will be $2000 for the 100 MW. The forward market settlement allows it to lock-in a price of $20/MWh for 100 MW, whether the real-time HOEP is greater or less than the forward market price. If the HOEP is less than the forward market price, it will owe money in the forward market settlement; conversely, if the HOEP is greater than the forward market price, it will be paid in the forward market settlement. Within Ontario, the combination of the forward market and real-time market settlements in Ontario produces the same net billing result, with non-locational pricing, as does the two-

[50] The HOEP is the hourly load-weighted average of the 5-minute real-time energy prices in Ontario. Thus, the Energy Forward Market may provide a complete hedge for transactions that settle at the HOEP in real time. Such transactions include non-dispatchable loads and intermittent and other small, self-scheduled

settlement systems used in other ISOs, although the specific accounting implementation is different.

There is no day-ahead unit commitment currently planned in Ontario that would correspond to the day-ahead unit commitment that is part of the day-ahead markets in PJM and New York.

3. Real-Time Market and Pre-Dispatch

a) Dispatch Data Submission

Ontario's real-time market is based on supply offers and demand bids by registered generators, loads and boundary entities. These offers and bids are also used for the IMO's pre-dispatch scheduling program, which is run approximately hourly starting at 12:00 noon of the day before each dispatch day.

Supply offers and demand bids into the Ontario real-time market can be modified without restriction until four hours before the real-time dispatch. Four hours before the dispatch, the IMO will impose a 10% limit on the magnitude of further price and/or quantity changes.[51] Bids will become firm two hours before real time, although changes may be made if approved by the IMO. Real-time supply offers and demand bids may consist of up to 20 price-quantity pairs. With the exception of boundary entities, offers and bids may include five ramp rates spread over the 20 bid points. Boundary entity offers and bids are not ramp restricted.

Dispatchable load will be treated identically to dispatchable generation in the Ontario market. Any load that can adjust to the 5-minute dispatch is eligible to bid. Exports are expected to be the largest source of dispatchable load in the Ontario market. Because export schedules are set hourly, export load bids need only be dispatchable on an hourly

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generators. All other real-time injections and withdrawals settle based on the 5-minute real-time price, not the HOEP, so that the Energy Forward Market provides an approximate hedge.

[51] Quantities may be changed by the greater of 10% or 15 MW.

basis. As in other regions, virtual bidding is not permitted within Ontario in the real-time market. With the exception of bids for export supply and demand, all offers and bids must be associated with physical generation and load.

b) Pre-Dispatch

Starting at 12:00 p.m. on the day before each dispatch day, and up to one hour before real time, the IMO will run a pre-scheduling program based on the bids and offers that it has received. The program is used to provide market information by way of hourly updates, which include expected hourly schedules and prices to all market participants.

The pre-dispatch program is primarily a forecasting tool that provides the IMO and market participants with advance information and projections necessary to plan the physical operation of the electricity system.[52] The IMO checks the reliability of the pre-dispatch schedule relative to its own load forecast[53] and locational requirements for energy and operating reserves. If the pre-dispatch schedules indicate that the IMO needs more energy or operating reserves to maintain the reliability of the grid, it may for local issues request the submission of additional bids and offers from resources that can be made available within the time required. The IMO may also issue system status reports whenever appropriate, for example to provide information to the market indicating a global generation deficiency or overgeneration. In an emergency, the IMO may import "emergency energy," but in no circumstance may it order internal resources to operate inconsistently with their bids and offers.[54]

The pre-scheduling program is also used to set external schedules for the dispatch hour. This process will be completed in time for transaction check out with adjacent control areas at 30 minutes before real time. Exports and imports will be scheduled for 12

[52] According to the market rules, the IMO is not required to run the pre-dispatch program every hour, but need only run it to evaluate changes in system conditions. As a practical matter, the IMO is currently planning to automate the pre-dispatch on an hourly basis.
[53] Ontario uses forecast average demand for the hour for its hourly schedule, unlike NY, which uses the forecast peak hourly demand.

external intertie zones: eight with Quebec, plus New York, Michigan, Manitoba and Minnesota. The IMO accepts bids to export and offers to import from “boundary ent for each of these external intertie zones. These bids and offers need not be tied to physical generation or load, although for reliability purposes the IMO must know the sending or receiving control area in addition to the boundary zone.

The hour-ahead scheduling of external transactions will be based on a bid-based market mechanism. When transmission constraints on imports are binding, market participants seeking to sell energy into the Ontario market will be scheduled hour ahead based on their supply offers, with the sellers with the lowest offers scheduled to flow in real time. Conversely, when transmission constraints on exports are binding, market participants seeking to buy energy from the Ontario market for export will be scheduled hour ahead based on their demand bids, with the buyers willing to pay the most for energy being scheduled to flow in real time. Wheeling-through transactions are bid as an individual energy offer from a boundary entity injecting energy from an intertie zone, and an energy bid from a boundary entity withdrawing energy from a different intertie zone. Unlike New York, NEPOOL and PJM, there is no ramping constraint on hour-ahead schedule changes, because Ontario does not have the ramping restrictions faced by the other regions.

In real time, the IMO will dispatch the Ontario system every five minutes, given the pre-determined external schedules. The dispatch software will use a model of the Ontario transmission system that includes all internal constraints and an equivalenced representation of the transmission system outside of Ontario.

c) Real-Time Settlements

For each generator and dispatchable load within Ontario, real-time settlements will be based on the uniform 5-minute ex-post MCP and their 5-minute dispatch schedule. The

[54] The market rules allow the IMO to direct the resubmission of quantity bids by registered resources that may be used to address local reliability concerns.

real-time MCPs are calculated from the hypothetical dispatch of an unconstrained grid (i.e., ignoring transmission system constraints), while the 5-minute dispatch signals are based on the dispatch of a grid that includes all Ontario transmission constraints.[55] Real-time settlements for non-dispatchable loads and intermittent and self-scheduling generators will be based on the hourly Ontario energy price, HOEP. There are no price or bid caps in the Ontario market at this time, although the market rules state that the IMO Board may set a maximum price for energy and operating reserves. Market power mitigation plans for Ontario Power Generation limit the revenue that it can earn on 90% of its forecast domestic sales, but do not cap its bids.

The hour-ahead pre-dispatch process determines an hourly Intertie Congestion Price ("ICP") that the IMO will use to settle external transactions for that hour. The ICP for an intertie is the external zone price at the intertie point minus the Ontario uniform price in the hour-ahead pre-scheduling program. The ICP may be either positive (when there is a constraint on exports) or negative (when there is a constraint on imports). Real-time settlements for external transactions will be based on the 5-minute Ontario MCP, plus the market clearing *hourly* ICP for the appropriate zone.[56] The settlements for external supply and load are based on hour-ahead external schedule quantities,[57] even if the total scheduled flow with neighboring control areas is more or less than actual physical flows as measured at metering points. Deviations between scheduled and actual flows will be accumulated as inadvertent and paid back in peak and off-peak periods, following current

[55] In both the pre-dispatch and in the real-time dispatch, the IMO will actually be running two software programs. The "unconstrained" model does not include any transmission constraints within Ontario and represents external zones as radial connections to Ontario with intertie limits. This model is used to determine all prices, both Ontario MCPs and the Intertie Congestion Prices for the interties. The "constrained" model includes all transmission constraints within Ontario and an equivalenced representation of the transmission network outside of Ontario. This model is used for the real-time dispatch, for hour-ahead scheduling of external transactions and to determine pre-dispatch schedules. Unlike the software used in New York and planned for the ISO-NE, the software planned in Ontario will not explicitly model line losses. Instead, estimated losses will be modeled as load and paid for through uplift.

[56] This is similar to ECA "B" in New York, under which external transactions may settle at the hourly BME price when there is congestion.

[57] Settling hour-ahead external schedules based, in part, on 5-minute prices allows the possibility of inconsistencies between external schedules and prices. This issue was considered and it was decided not to pay uplift to external transactions to cover a shortfall between their bids and prices. Instead, market participants are encouraged to hedge this risk, if desired, through bilateral contracts or the forward market. Externals are paid uplift for congestion within Ontario.

-off" payments may also be made to loads if the IMO accepts demand bids to manage congestion. The quantities subject to constrained-on or -off payments are determined ex post based on the differences between the quantities dispatched in the unconstrained model and the actual constrained system dispatch.[58]

The Ontario energy market is based on one-part offers to buy and bids to sell energy. Only intermittent (wind) and a few other small generators will be permitted to submit fixed schedules. With these exceptions, all resources in Ontario are dispatched by the IMO based on a one-part bid for incremental energy. Generators with start-up costs, minimum loads, minimum run times, ramping limits, etc., are expected to structure their one-part bids so that the IMO dispatches them consistently with the planned physical operation of their units. For example, if a generator plans to come on line at 6 a.m., it must structure its supply offer so that the IMO will activate the offer at the correct time. Market participants are expected to watch the hourly pre-dispatch prices in determining how to operate and adjust the bids for their resources.[59] There are no "make-whole" payments paid to generators, as in systems with three-part bidding.

[58] See previous footnote.

[59] The market rules recognize that *hourly* bids may be difficult to structure to elicit appropriate dispatch instructions for units that are ramping. Therefore, special rules allow units to inform the IMO two hours

Bilateral transactions will not be physically scheduled in Ontario, but market participants may achieve the equivalent of a fixed transaction by offering supply at a very low price and bidding the corresponding load at a very high price. Market participants may also specify "physical bilateral" transactions, which the IMO accommodates in the settlement process, identically to the eSchedules in PJM. The IMO will decrease the settlement obligation of a buyer under a physical bilateral contract, and will increase the settlement obligation of the seller; i.e., a generator that injects 100 MW into the real-time market would be paid the Ontario MCP for 100 MW less its physical bilateral sales quantity. Physical bilateral contracts may be included in the IMO settlements if they are specified no more than seven days ahead of the dispatch day or six days after. Market participants may also enter into financial bilateral transactions that are settled privately between the parties to the contract and do not enter into IMO settlements.

4. Ancillary Services

There are two methods of acquiring ancillary services for the IMO market: (1) with periodic contracts awarded through competitive processes, and (2) through real-time markets.

The first type of ancillary services, procured by the IMO through contracts, includes regulation, voltage control/reactive support and black start capability. These ancillary services will be procured locationally and, to the extent practicable, acquired at competitively determined prices using competitive processes. Payments to contracted suppliers may include the cost of being available to provide the ancillary service, and the out-of-pocket and opportunity costs of actually providing the ancillary service when instructed to do so by the IMO. In real time, units with contracts are given their schedules by the IMO prior to the dispatch interval. The IMO may also enter into Reliability Must-Run Contracts with specific resources that are required to be available,

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ahead of the dispatch about their plans for synchronizing or desynchronizing with the system during an hour.

or to be dispatched out-of-merit, to address local area transmission constraints or voltage requirements.

The second type of ancillary services consists of three types of operating reserves: 10-minute synchronized reserves, 10-minute non-synchronized reserves and 30-minute reserves. Market participants can submit offers, with up to five price-quantity pairs, for each class of operating reserve. These offers are considered in the pre-dispatch and real-time dispatch simultaneously with bids and offers for energy.[60] The software allows capacity to be bid as both energy and reserves. The IMO software then simultaneously optimizes the selection of offers to provide either energy or operating reserves, while also taking into account ramping. Like the software in New York and planned for ISO-NE, the IMO software also recognizes the relationships between reserve categories, so that the requirement for 30-minute reserves, for example, could be satisfied by either 10-minute synchronized reserves, 10-minute non-synchronized reserves or 30-minute reserves. The IMO will determine a 5-minute price for each type of operating reserve in its unconstrained pricing model. Because the software recognizes relationships between reserve categories, the settlement price for higher quality of reserves will always be greater than that for lower quality reserves.

Providers of operating reserve are selected and paid in each 5-minute dispatch. External offers are scheduled using the same pre-dispatch process as that used for external energy offers and bids. If a contingency occurs during the 5-minute interval, the selected providers are notified and must perform according to the terms of their offer. There are no forward markets in operating reserves; they are all scheduled in real time. However, as part of the pre-dispatch process, the IMO will inform market participants of their forecast individual schedules for providing operating reserves, and will issue advisories to all market participants indicating operating reserve shortfalls for each dispatch hour.

Each offer to provide operating reserve must be accompanied by a corresponding energy offer or energy bid that covers the same MW range. In the real-time dispatch, if

[60] There are locational reserve requirements in Ontario.

operating reserves are activated, these offers to supply are cleared along with all other energy offers and energy bids. The IMO will not curtail energy to provide operating reserve. Instead, it will apply a penalty function when it falls below its target for any type of operating reserve. The penalty function will send a signal to the market by increasing energy and reserve prices towards an implied shortage cost. The characteristics of these penalty functions, and of the extent to which they will impact prices, are currently under discussion in Ontario.

In addition to contracted ancillary services and operating reserves, the market rules allow the IMO Board to activate a capacity reserve market based on forecasts of capacity in the market. The implementation of this market is presently planned to occur 12 months after the start of the energy market. If activated, bids for capacity reserve are accepted, and a clearing price for capacity is calculated by equating the amount of capacity reserve offered with the amount required. Market-clearing quantities of capacity reserve are submitted to the settlement process. A market participant who sells capacity reserve accepts an obligation to offer energy and/or operating reserves in the next pre-dispatch day. In other words, the IMO can call upon any market participant who sold capacity reserve in the capacity reserve market for Day 1 to submit offers to provide energy and/or operating reserves on Day 2 for use in the Day 3 dispatch.

5. Transmission Rights

The Ontario market will offer transmission rights ("FTRs") to hedge congestion costs associated with transactions between the IMO control area and adjoining external zones. Each FTR is associated with a specific injection TR zone and a specific withdrawal TR zone – one of which is the IMO control area and the other of which is outside the IMO. Holders of FTRs, which are options, are paid the greater of: (1) zero, or (2) the ICP, which is equal to the TR settlement price at the withdrawal zone minus the TR settlement price at the injection zone. The IMO will sell FTRs through an auction. Using a forecast of available transmission transfer capability, it will conduct a simultaneous feasibility test during each FTR auction to ensure that ICP congestion rents will be sufficient to pay the obligations owed for all outstanding FTRs. The feasibility test is not expected to sell FTRs up to the limits of the transmission system, since it will incorporate probabilistic estimates of contingencies and transmission capacity.

D. PJM

PJM Interconnection, LLC ("PJM") became the first operational ISO in the U.S. on January 1, 1998. Its objectives are to ensure the reliability of the bulk power transmission system and to facilitate an open, competitive wholesale electric market. PJM operates the largest centrally dispatched electric system in North America, and the third largest in the world.

PJM implemented its Open Access Transmission Tariff on April 1, 1997, and began operating the nation's first regional, bid-based wholesale energy market. In April 1998, PJM implemented a system of locational marginal pricing ("LMP") for settling the price of energy transactions and transmission usage in its wholesale markets. Until the Spring of 2000, PJM operated a day-ahead scheduling process followed by settlements based on the LMPs determined for the real-time dispatch. On June 1, 2000, it began operation of a two-settlement system, consisting of both a day-ahead financial market and a real-time balancing market. Generation resources are either self-scheduled or scheduled by the PJM Office of Interconnection ("OI") based on bids submitted in the day-ahead market and the balancing market. The day-ahead market settlement is based on scheduled hourly quantities and hourly LMPs determined in the day-ahead unit commitment and dispatch. The balancing market is settled based on real-time LMP values averaged over the hour and deviations between real-time quantities and the day-ahead schedules.

Like NEPOOL, Ontario and New York, PJM has implemented a system of financial transmission rights, called Fixed Transmission Rights ("FTRs") to provide a hedge against congestion prices.

1. Overview of the PJM Markets

The PJM day-ahead market is a forward financial market in which day-ahead schedules and locational market-clearing prices (LMPs) for energy are calculated for each hour of the following operating day. The day-ahead market is based on a security-constrained economic unit commitment and dispatch program. The program is run using generation bids, price-sensitive load bids, increment and decrement bids and external transaction bids (which may or may not have associated prices) that are submitted to the day-ahead market. Increment and decrement bids are virtual generation and load bids that participants may use to arbitrage prices or to purchase day-ahead price hedges. The day-ahead software takes into account self-scheduled generation and then determines the unit commitment profile that satisfies the fixed demand, cleared price-sensitive demand bids, and PJM operating reserve objectives, while minimizing the total bid production cost. Hourly day-ahead LMPs and schedules are determined at the conclusion of the day-ahead unit-commitment and dispatch and used to calculate day-ahead energy settlements.

Since the day-ahead market is purely financial, day-ahead schedules and settlements need not be associated with physical load or generation. The day-ahead market allows market participants to purchase and sell energy at binding day-ahead prices, and allows transmission customers to schedule bilateral transactions at binding day-ahead congestion charges (based on the difference in LMPs between source and sink). Day-ahead schedules, prices and settlements are determined at a variety of locations to support trading: buses, hubs, zones, retail aggregate buses and external interface buses.

Units that are scheduled day-ahead to provide operating reserves are compensated, if necessary, through make-whole payments based on the daily shortfall between their three-part day-ahead energy bids and the day-ahead energy market prices. A separate market for regulation is conducted after the day-ahead market has concluded.

Bids for the day-ahead market are due by 12:00 noon on the day prior to the operating day. PJM then runs the unit commitment software for the day-ahead market and, by 4:00 p.m., posts on the internet its load forecast, the total bid-in demand, its operating reserve objective, the schedule of demand and the LMPs for each hour of the next operating day.

At the same time, market participants are informed of their day-ahead schedules. At 4:00 p.m., PJM's balancing market opens. From 4:00 p.m. to 6:00 p.m., market participants can submit revised price bids for units not selected in the day-ahead market. These bids will be used in both the balancing market unit commitment and in the real-time dispatch. Market participants may also submit fixed schedule changes any time up to 20 minutes before the real-time dispatch. At 6:00 p.m., PJM performs the balancing market unit commitment. The purpose of this second unit commitment is to ensure that it can reliably meet forecast load. During the second unit commitment, PJM may commit additional generating units but may not decommit any units committed in the day-ahead market. At the conclusion of the second unit commitment, schedule changes are communicated to generating units and dispatchable loads, but no LMPs are calculated and there is no financial settlement. Up to 20 minutes before the real-time dispatch, PJM continues to allow fixed schedule changes, such as new transactions, changes to existing transactions (MW schedules) and changes to self-scheduled unit output,. However, it does not allow changes to price bids following the balancing market offer period. In real time, PJM dispatches the system every five minutes. The balancing market settlement is based on real-time quantities and the hourly average of the 5-minute real-time prices.

The following sections describe the elements of the PJM day-ahead market, including: products, energy market bids, external and internal bilateral schedules, ancillary services, and fixed transmission rights. The final section discusses the PJM unit commitment software in the context of presenting a detailed timeline of the PJM markets.

2. Products

PJM schedules two products in the day-ahead market: energy and operating reserve. Operating reserves include "primary" and "secondary" reserves. Primary reserves consist of spinning reserve (10-minute spin) and quick-start reserve (10-minute non-spin). Secondary reserves, also called 30-minute reserves, may or may not be synchronized to the grid.

Upon completion of the day-ahead market for energy and operating reserves, PJM conducts a regulation market and calculates the market-clearing price for regulation available for the next day.

3. Energy Bidding in the Day-Ahead Market

a) Generation Bids

There are two categories of generation in PJM: Designated Capacity Resources[61] and Non-Designated Capacity Resources. A generator that is a Capacity Resource must offer itself into the day-ahead market, either by self-scheduling or bidding for dispatch, even if it is unavailable due to outage. Non-Designated Capacity Resources may offer into the day-ahead or real-time markets

Generation offers are three-part bids, consisting of start-up, no-load and incremental energy components. The incremental bid curve may consist of up to ten segments. Generators may submit market-based rather than strictly cost-based bids. However, one cost-based schedule must be made available to PJM in the event that the unit is used to control a transmission constraint. Generation offers may not exceed $1,000/MWh and may not be negative.[62] Self-scheduled generation must submit an hourly MW schedule for the day-ahead market, and may also submit a decremental bid.

A generator offer that is accepted for the day-ahead market automatically carries over into the balancing market and is included in the real-time dispatch. If a generator is not scheduled at all in the day-ahead market, it may revise its offer and resubmit it into the real-time market.

b) Generation Bids in the Presence of Transmission Constraints

[61] A Capacity Resource is the net capacity a load-serving entity uses to meet its obligation under its Reliability Assurance Agreement.
[62] No bids into the PJM market may be negative.

If the day-ahead scheduling process identifies transmission constraints that confer local market power, generators that relieve the constraints become subject to bid caps. Generating units may choose to set their bid caps based on either cost (production cost + 10%) or historic LMP. Start-up and no-load components of the bid are capped at production cost + 10%. The bid caps are in effect for only those hours in which the generator is designated as "on for transmission" and may be used to set LMP. Bid caps are not used for resources that are dispatched for western, central or eastern reactive limits.

c) Price-Sensitive Demand Bids

The PJM day-ahead market accommodates both fixed demand bids and price-sensitive demand bids. For fixed demand bids, market participants submit hourly demand quantities to the day-ahead market and commit to purchase energy for these demand quantities at the day-ahead market price. The bids must specify the MW quantity and the location (transmission zone, aggregate bus distribution or single bus).

Price-sensitive demand bids specify the MW quantity, location and the price at which demand will be curtailed. Price-sensitive demand bids are accepted only in single bid blocks. Market participants may submit up to nine bid blocks at a specific location. Price-sensitive demand bids, incremental bids, and decremental bids must be consistent with the $1000/MWh price cap.

d) Increment and Decrement Bids

Any market participant, including generators and loads, may submit increment and decrement bids into the PJM day-ahead market. Increment and decrement bids, also called "virtual bids," are not associated with physical load or generation and must be made as blocks. Each bid may include up to five blocks, but since a market participant may submit any number of bids, the number of bid blocks is essentially unlimited.

Increment and decrement bids may be submitted at any hub, transmission zone, aggregate bus distribution or single bus for which an LMP is calculated.

4. Transmission Service and Bilateral Transactions

In PJM there is an important distinction between external and internal bilateral transaction schedules. External transaction bids and schedules are included as inputs in the unit commitment and dispatch software. Internal bilateral transaction schedules, on the other hand, are used only to calculate financial settlements in the PJM markets. Called "eSchedules," internal transaction schedules rearrange the settlements resulting from the day-ahead unit commitment and dispatch, but are not inputs to the unit commitment process itself.

a) External Transactions

Market participants that undertake external transactions in PJM make a series of decisions from the time that they make their transmission reservation to the time that they submit their transaction schedule. These decisions reflect important choices regarding: the injection and/or withdrawal locations for their transaction, the type of transmission service that they elect, whether or not they elect to be included in the two-settlement system, whether or not they reserve ramping day-ahead, and whether or not they include price or congestion bids with their transaction.

Transaction Injection and/or Withdrawal Locations. With a few exceptions, all external transactions in PJM consist of bids or schedule requests at a single interface bus between PJM and an adjoining control area. Typical examples of external transactions are fixed schedules or price-sensitive bids to inject or withdraw energy at an interface bus. Only two specific types of external transactions specify both an injection and a withdrawal bus: wheeling transactions and transactions with "up to" congestion bids.

Valid sources and sinks for external transactions include a list of transmission buses shown in Attachment E to the PJM Scheduling Operations Manual. In addition, transactions may be made to and from three types of aggregate buses.

- Hubs. PJM has defined three regional hubs: the western interface hub (3 buses); the eastern hub (237 buses); and the western hub (111 buses). The hub prices are the weighted average LMPs of the buses comprising the hub. The weights are fixed and equal for each bus.

- Zones. PJM has defined eight utility zones. The LMP for a zone is calculated from the load-weighted LMP and the scheduled sales-weighted LMP for the zone.

- Retail Buses. Retail buses are defined to facilitate bidding and scheduling by load aggregators that serve retail load.

For external transactions, PJM recognizes five external interface buses. There are two with New York and one each with Allegheny Power System, Virginia Power and Cleveland Electric Illuminating Company. The two New York interfaces are called NYPP-E and NYPP-W. When scheduling a transaction, market participants need to specify whether it is crossing the PJM/NY East or PJM/NY West interface. PJM requires transactions flowing into or out of New York zones A, B, C, and O to be designated as NYPP-W flows, and transactions flowing into or out of New York zones F, G, H, I, J, K, and N to be designated as NYPP-E flows. Transactions flowing into or out of New York zones M, D, and E can be designated as either.

Transmission Service and Willingness to Pay Congestion. All external transactions must reserve and purchase transmission service over the PJM OASIS in order to submit a transmission schedule to PJM using the Enhanced Energy Scheduler ("EES") application.[63] All external schedules in PJM are scheduled using EES. Transmission customers may choose Firm or Non-Firm Point-to-Point Transmission Service.

- Firm Point-to-Point Transmission Service is available up to the limits of transmission system capacity.[64] Election of Firm Transmission Service indicates that the transmission customer is willing to pay congestion charges. To hedge these charges, customers taking firm service may elect to receive FTRs that correspond to their service. The FTRs are assigned in MWs between the injection and withdrawal points listed in the transmission reservation.

  Requests for Firm Point-To-Point Transmission Service must be submitted to the PJM OI before 10:00 a.m. of the day before the operating day.[65] Transactions submitted after this deadline are accommodated, if practicable. The 10:00 a.m. deadline is imposed to enable PJM to assign an OASIS number to the reservation in time for the transaction to be submitted to the day-ahead market. The OASIS number must be entered when transactions are scheduled in the EES, which must occur by the 12:00 noon deadline for the day-ahead market.

- PJM sells unlimited Non-Firm Point-to-Point Transmission Service for external transactions. Customers taking non-firm service further elect whether or not they are willing to pay congestion. The day-ahead market in PJM is used only to schedule transactions that are willing to pay congestion. Transactions that are not willing to pay congestion may not enter into day-ahead financial settlements; they are considered in the real-time balancing market, along with other transactions that are willing to pay real-time congestion.

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[63] Spot market imports where the sink is the same as the interface through which the energy is imported are not required to purchase transmission.
[64] The Capacity Benefit Margin is subtracted in the determination of the transmission capacity available for firm service.
[65] This deadline also applies to requests for non-firm transmission service. In practice, however, requests for non-firm service may be handled relatively quickly since they require no evaluation of transmission availability.

Firm Point-to-Point and Non-Firm Point-to-Point Service that is willing to pay congestion are scheduled identically in PJM. Both may be used to schedule transactions either with or without price or congestion bids and may be used to schedule transactions in either the day-ahead or balancing markets. The election of firm service provides no scheduling priority; scheduling priority is determined based on price or congestion bids (if any) and on the availability of ramp room. The principal distinctions between Firm Point-to-Point Transmission Service and Non-Firm Point-to-Point Transmission Service are that firm service has a higher priority if transmission service must be curtailed and may elect to receive FTRs. All FTR requests are subject to a PJM feasibility test.

Two-Settlements versus Real Time Only. Like internal transactions, external transaction schedules elect whether to be included in the two-settlement system, in which case they participate in the day-ahead financial market, or to be included only in the real-time balancing market.

- Transactions that are included in the day-ahead market are called Two-Settlement Transactions. They may or may not include price or congestion bids, but must be willing to pay congestion. Two-Settlement transactions may be submitted for some or all hours of the dispatch day. Price bids may vary by hour with the exception of bids from generators. The deadline for submitting all Two-Settlement Transactions into the EES is 12:00 noon on the day before the dispatch day.

- Transactions that are settled in the balancing market are called either Pre-Scheduled Real-Time Transactions or Hourly Transactions. The deadline for submitting transactions that settle in the balancing market varies depending upon whether they are pre-scheduled in order to reserve ramping, and whether they also include a price bid.

Pre-Scheduling and Ramping. Like most control areas, PJM does not have unlimited ramping capability between hours. In order to ease this restriction, it ramps units four times an hour. Nevertheless, it must impose limits on the total amount of ramping that can be accommodated during any 15-minute interval.[66]

Market participants scheduling external transactions must decide whether or not to pre-schedule their transactions in order to reserve ramping. Ramp room is allocated on a first-come, first-serve basis to market participants based on the time that their external transactions are pre-scheduled in EES.[67] Transactions that fit the ramp and pass all other EES validation checks are "pre-approved" and hold ramp room.[68, 69] The time at which pre-scheduled ramp room is assigned by EES depends on the type of transaction (Two-Settlement or Pre-Scheduled Real-Time) and on whether or not the transaction is made with a price bid. There is also a third type of transaction, Hourly Transactions, which does not hold pre-scheduled ramp room.

- Assignment of ramping to Two-Settlement Transactions.

    - Two-Settlement Transactions without price bids are assessed for ramp room when they are entered into EES. If there is sufficient ramp room, they will be "pre-approved."

    - Two-Settlement Transactions with price bids are assessed for ramp after their bids are accepted in the day-ahead market.

[66] External transactions are subject to the 500 MW net ramp and 1000 MW NYPP ramp rules. Under the 500 MW net ramp rule, the change in net interchange between PJM and its neighbors cannot be greater than 500 MW or less than –500 MW during any 15-minute interval. Under the 1000 MW NYPP ramp rules, the difference in the interchange between PJM and New York cannot be greater than 1000 MW or less than –1000 MW during any 15-minute interval.
[67] Ramp room may be reserved, at the earliest, 18 months in advance for transactions without price bids. Transaction schedules may be entered into EES after a transmission reservation has been made on OASIS, which can occur up to 18 months in advance. Transactions without price bids are evaluated for ramp after their schedules are entered into EES.
[68] All transactions entered into the EES must have a valid NERC tag and an OASIS reservation number.
[69] Transactions that are denied by EES due to ramp violations may be modified and re-submitted to PJM. PJM continuously monitors ramp as schedules are entered into EES and updates its evaluation as schedules change.

- Assignment of ramping to Pre-Scheduled Real-Time Transactions. Transactions that elect to settle in the real-time market may request to be Pre-Scheduled in order to hold ramp room. The deadline for submitting Pre-Scheduled transactions depends upon whether or not they include price bids.

  - Pre-Scheduled Real-Time Transactions without price bids are assessed for ramp when they are entered into EES. If there is sufficient ramp room, they will be "pre-approved." The deadline for these transactions is 2:00 p.m. of the day before dispatch.

  - Pre-Scheduled Real-Time Transactions with price bids are assessed for ramp after PJM has run its balancing market unit commitment. This is a second unit commitment step that is run after the day-ahead market in order to evaluate and insure system reliability. Real-Time with Price Transactions are included and evaluated in this software step to enable the OI to assess the real-time reliability of the system after taking into account which of the Real-Time with Price Transactions are likely to flow. Therefore, after the dispatch step of the balancing market unit commitment, the dispatcher is able to make an initial determination of whether or not Real-Time with Price Transactions will clear in the real-time dispatch.[70] Following this decision, the dispatcher fits these transactions into the ramp, if possible.[71] The deadline for these transactions is 12:00 p.m. of the day before dispatch.

- No assignment of ramping to Hourly Transactions. Transactions that settle in real time but are not pre-scheduled are called Hourly Transactions. These transactions do not hold pre-scheduled ramp room, but are accommodated on a first-come, first-serve basis to the extent that ramping room is available.

  Hourly transactions may not include price bids; they are all "fixed" or "LMP price

[70] The dispatcher may update or change this assessment if system conditions change.
[71] Dispatchers may attempt to make transactions fit the ramp by moving them backward or forward in time by 15 minutes.

taking" transactions. They may be wholly new transactions or may be submitted as a result of a generator electing to go off of dispatch and submit a must-run schedule to the OI. Under a pilot program announced on December 28, 2000, most types of hourly transactions and schedule changes may be submitted to PJM via the EES system with only 20 minutes notice. A notable exception is that new interchange transactions must continue to be submitted 30 minutes before the real-time dispatch. New transactions submitted by telephone must continue to be made at least 60 minutes before the real-time dispatch.

Price and Congestion Bids. Price and congestion bidding takes a number of forms in PJM. Transactions may be made: with price bids, with "up to" congestion bids, with no -takers") or as not willing to pay congestion. Different types of price-related information are allowed with different types of transactions.

- With Price Transactions. Two-Settlement Transactions and Pre-Scheduled Real-Time Transactions may be made "with price." With price transactions are bids to inject or withdraw energy at one of PJM's interface buses with an adjoining control area. These bids may be made either as blocks or as monotonic bid curves. External supply bids that are resource-specific may bid start-up and no-load costs into PJM and are eligible for make-whole payments if they fail to cover their bids.[72]

- "Up To" Congestion Bids. Two-Settlement Transactions may, alternatively, be made with "up to" congestion bids indicating the market participant's willingness to pay congestion charges. "Up to" congestion bids may be no larger than $25/MWh. Any "up to" congestion transaction bids that are higher than $25/MWh will be treated as fixed bilateral transactions. Congestion bidding is accommodated only in the day-ahead market and only as a block bid. Two-Settlement Transactions may submit an "up to" congestion bid of zero.

[72] Other types of external transactions are also eligible for make-whole payments if PJM schedules them and prices fall below their bids.

- No Price Bid ("LMP Price-Takers"). Two-Settlement and Pre-Scheduled Real-Time transactions also may be made without price or congestion bids. All hourly transactions *must* be made without price or congestion bids, although they may indicate that they are not willing to pay a congestion charge. Any transaction without a price bid is called a "basic energy transaction" or "fixed bilateral transaction." These comprise the majority of the transactions scheduled with PJM. The parties to these transactions are "LMP price-takers."

- Not Willing to Pay Congestion. Pre-Scheduled Real-Time and Hourly Transactions may indicate that they are not willing to pay congestion. The PJM dispatchers will load these transactions if there is no congestion and will cut them as soon as possible after congestion develops in real-time. They will not be assessed a charge if congestion develops before they are cut.[73]

In summary, the scheduling deadline for submitting each of the types of external transactions discussed above to PJM via the EES system is:

- Two-Settlement Transactions: 12:00 noon on the day before the dispatch day.
- Pre-Scheduled Real-Time with Price Transactions: 12:00 noon on the day before the dispatch day.
- Pre-Scheduled Real-Time Transactions without price: 2:00 p.m. on the day before the dispatch day.
- Hourly Transactions: with 20 minutes notice via the EES system.
- Requests for Firm Transmission Service: 10:00 a.m. on the day before the dispatch day.

[73] These transactions may be accepted if the congestion charge is negative in the balancing market, i.e., if they alleviate congestion. However, they will not be paid the negative congestion charge.

b) Internal Bilateral Transactions

In PJM, internal bilateral transaction eSchedules are used only for calculating LMP settlements for the parties to the transaction. For example, if a load submits a fixed schedule for 100 MW into the day-ahead market, and also is a party to a day-ahead eSchedule for 90 MW for delivery at the same location, its 100 MW day-ahead settlement obligation will be reduced to 10 MW. Similarly, if the generator that is party to the transaction submits a fixed schedule to inject 125 MW at the delivery location specified in the eSchedule, it will receive a day-ahead LMP payment for only 35 MW. The generator will be paid bilaterally by the load for the 90 MW under the contract. The eSchedules thus affect only the LMP settlements for the parties to the contracts; they do not impact, nor are they used, in the physical scheduling of the transmission system. eSchedules that designate the day-ahead market are settled based on day-ahead prices, while those that designate the balancing market are settled at balancing market (real-time) prices

5. Ancillary Services

a) Regulation Market

PJM conducts a regulation market following the conclusion of the day-ahead energy market. The total PJM regulation requirement is determined for both peak and off-peak hours. Currently, it is set to 1.1% of the day-ahead peak load forecast for the peak period, and 1.1% of the "valley load forecast" for the off-peak period.

Generators located within the PJM control area may submit unit-specific offers to provide regulation between 4:00 p.m. and 6:00 p.m. on the day prior to operation. Offers are for a specific MW quantity at a specific offer price in $/MWh. Offers include only one price-quantity pair. The offer price is capped at $100/MWh.

Regulation may either be self-provided, purchased through bilateral transactions or purchased from the PJM interchange market. Bilateral regulation transactions affect financial settlements but not the operation of the PJM system. Therefore, they may be submitted to the OI for settlement purposes up to 12:00 noon on the day after the transaction starts.

To clear the regulation market, PJM uses the LMPs and generation schedules from the day-ahead market to forecast an hourly opportunity cost of providing regulation. The estimated opportunity cost is then added to regulation bids for each hour and stacked in merit order. The lowest bid necessary to meet the PJM regulation requirement sets the Regulation Market Clearing Price ("RMCP") for that hour. Generation owners that self-schedule regulation are given a merit order price of zero. The regulation market clears by 10:00 p.m. on the day prior to operations. The RMCP is used to determine the credits awarded to providers of regulation and the charges allocated to purchasers.

b) Operating Reserves

Operating reserve is reserved capacity that can be scheduled as energy within 30 minutes of a request by the PJM dispatcher. PJM schedules three types of reserves in the day-ahead market: 10-minute spinning reserves, 10-minute non-spinning reserves (quick start) and 30-minute (secondary) reserves. Higher quality reserves can qualify as lower quality reserves. Thus, spinning reserve can also qualify as quick start or secondary reserves. Similarly, quick start reserve can qualify to provide secondary reserves.

Operating reserve is scheduled simultaneously with energy in the day-ahead unit commitment and dispatch process. It is capacity that is scheduled on top of the bid-load requirement.[74] The commitment of a unit to provide energy or operating reserves depends on its three-part energy bid alone. Generators that are scheduled to provide operating

[74] PJM reserve requirements are calculated on a seasonal basis. Operating reserve levels are calculated for various peak loads, and are probabilistically determined based on a season's historical load forecast error and expected generation mix. Primary reserve levels are also determined probabilistically using the

reserves are compensated with make-whole payments that are calculated separately for each unit. The make-whole payments compensate the units for the difference between their day-ahead energy revenues and their day-ahead bid cost for their scheduled level of output. Unlike New York and New England, there is no separate availability bid for each class of operating reserves and no separate market-clearing price for each class of reserve.

6. Fixed Transmission Rights

FTRs are financial instruments that compensate their owners for congestion charges that arise when the transmission grid is congested in the day-ahead market. The purpose of FTRs is to protect firm transmission service customers from increased cost due to transmission congestion when their energy deliveries are consistent with their firm reservations. Essentially, FTRs are financial entitlements to rebates of congestion charges paid by the firm transmission service customers. They do not represent a right for physical delivery of power. Like the TCCs in New York, FTRs are financial obligations and are subject to a feasibility test.

Each FTR is defined from a point of receipt (where the power is injected onto the PJM grid) to a point of delivery (where the power is withdrawn from the PJM grid). For each hour in which congestion exists on the transmission system, the holder of the FTR is awarded a share of the transmission congestion charges collected from the market participants.[75] The target payment to each FTR holder is equal to the LMP at the point of delivery minus the LMP at the point of receipt, multiplied by the number of megawatts of the FTR.

There are four ways in which FTRs can be acquired:

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season's typical generation mix. The current objective for primary reserves is 1700MW, subject to changes in the generation mix.

[75] FTRs are not "fully funded" like the TCCs in New York. If there is a shortfall in the revenue available to fund FTRs, FTR owners are paid in proportion to their target allocations of FTR revenue.

- Network Integration Service. Network Services FTRs are designated along paths from specific generation resources to a network customer's aggregated load. The network customer has the option to request FTRs for any or all portion of its generation resources. A network service customer's total FTR designation to a zone cannot exceed its total network load in that zone. Network service customers make FTR requests and modifications through an internet computer application called "*e*Capacity."

- Firm Point-to-Point Service. PJM allocates FTRs to firm point-to-point service customers for approved service requests. The point of receipt is either a generation resource within the PJM control area or the interconnection point with the sending control area. The point of delivery is the set of load buses designated in OASIS or the point of interconnection with the receiving control area. The duration of the FTR is the same as for the associated service request. Customers may choose not to accept Point-to-Point FTRs with their firm transmission reservation. Point-to-point transmission service is available to market participants on a first-come, first-serve basis.

- FTR Auction. PJM conducts a monthly process of selling and buying FTRs through an auction. The FTR auction offers for sale any residual transmission capacity that is available after network and long-term point-to-point transmission service FTRs are awarded. The auction also allows market participants an opportunity to sell and reconfigure FTRs that they are currently holding. Market participants offer to sell or request to buy FTRs through an internet computer application called "*e*FTR." FTRs acquired in the auction have a duration of one month.

- Secondary Market. The FTR secondary market is a bilateral trading system that facilitates trading of existing FTRs between PJM members through *e*FTR.

7. Day-Ahead Pricing and Settlements

PJM calculates LMPs for over 2,000 bus locations and for hubs, zones, retail buses and external interface buses. In the day-ahead market, the following generation resources are able to set the LMP: (1) all pool-dispatchable steam units, (2) pool-scheduled CTs and diesels whose bid price is at or below the system marginal cost, (3) dispatchable external resource offers, and (4) incremental bids. Demand bids that are eligible to set LMP are: (1) price-sensitive demand bids and (2) decremental bids. Finally, "up to" congestion bids provided with bilateral transactions are eligible to set LMP values in the day-ahead market. As previously noted, LMPs are calculated in the day-ahead market based on the first unit commitment, which satisfies the day-ahead bid demand plus the operating reserve objective for that level of demand. The LMPs include the marginal cost of congestion, but not the marginal cost of losses, as in New York and planned for New England.

Market participant purchases and sales and transmission customer transactions that are scheduled in the day-ahead market are obligated to purchase or sell energy, or pay transmission congestion charges, at the applicable day-ahead LMPs. For each hour, scheduled load pays its day-ahead LMP, while scheduled generation is paid its day-ahead LMP. Energy purchases and sales scheduled at external nodes are settled at the appropriate interface bus price for the external control area. Energy schedules based on increment and decrement bids are settled at the scheduled location, which may be a bus, hub or zone.

Scheduled transactions pay congestion charges based on day-ahead LMP differences between the point of injection and the point of withdrawal. This congestion charge is similar to the TUC in New York, except that it does not include a charge for marginal losses. It applies only to a small number of "up to" congestion and wheel-through transactions.

As noted previously, day-ahead settlements are also made for FTRs, regulation and operating reserves:

- FTR holders receive congestion credits based on the difference in the hourly day-ahead LMP values between the injection and withdrawal locations for the FTR.
- Generating units scheduled to provide regulation are paid the Regulation Market Clearing Price.
- Units scheduled to provide operating reserve receive make-whole payments. These are similar to the uplift payments paid to generators in the New York market and planned for New England. The total cost of operating reserve is allocated to total cleared day-ahead demand plus cleared day-ahead exports.

Following the day-ahead market, the balancing market settlement is based on the 5-minute real-time LMPs averaged over the hour and quantity deviations from day-ahead schedules.

8. PJM Market Timeline and Unit Commitment Software Description

PJM makes a clear distinction between the day-ahead market, which is financial, and the real-time balancing market, which is based on physical schedules. In the day-ahead market unit commitment, transaction schedules may be financial and virtual bidding of increments and decrements is accommodated. The actual physical scheduling of the system begins with a second unit commitment that is run after the settlement of the day-ahead financial market and ends with the real-time dispatch.

*12:00 noon of the day before operation*s. By this time all day-ahead bids and transaction schedules must be submitted to PJM. PJM then begins to run the two-settlement software to determine the hourly commitment schedules and the LMPs for the day-ahead market.

- The technical unit commitment software, called Resource Scheduling and Commitment ("RSC"), determines the unit commitment profile that satisfies the fixed demand, cleared price-sensitive demand bids, and PJM operating reserve objectives, while minimizing the total bid production cost.

- The commitment analysis includes fixed external bilateral transaction schedules, increment and decrement bids and external with price offers at interface buses.

  - Up to congestion transactions are not modeled in the commitment part of this analysis, but are handled in the final dispatch and scheduling step that occurs after the day-ahead unit commitment software has been run. PJM does not commit additional generation to support up-to congestion external transactions.

  - The day-ahead security analysis treats increment offers and decrement bids as load or generation at the location at which they are submitted. They can be submitted at any location, even at places where actual load and generation do not exist. Increment and decrement bids are permitted only in the day-ahead market. However, these virtual bids represent actual financial positions and therefore affect both day-ahead and real-time settlements. They can also affect which units are scheduled in the day-ahead market and may therefore have an impact on both day-ahead and real-time prices.

  - External supply offers can be made either on the basis of an individual generator (resource specific offer) or an aggregate of generation supply. External with price transactions are modeled as dispatchable generation or load at the interface bus.

- The unit commitment will economically schedule counterflow, if it is available. This may enable PJM to accommodate additional non-firm transaction schedules.

- Ramping limits are observed in the first unit commitment and dispatch.

- There is no explicit transmission model in the unit commitment analysis. Only certain transmission limitations (the PJM Western, Central and Eastern interface limits) are modeled using flow distribution factors.

- The unit commitment looks ahead over a week and thus may commit units with minimum run times that span two dispatch days. In days 2 through 7 the unit commitment software is looking only to see if it will have sufficient capacity to meet demand. The analysis determines whether PJM will need to start one or more units with long start-up times in order to meet demand in subsequent days. Since generators may bid minimum run times up to 24 hours, a generator committed during the first day of the market may not reach the end of its minimum run time until the second day. Generators that are committed by PJM that have notification, start-up, and minimum run times that extend beyond the first day of the unit commitment receive a make whole guarantee for their whole minimum run time.[76] To avoid gaming, at the time that they are committed their bids for the next day are locked in for the next seven days. With the exception of these generating units with long minimum run times, the day-ahead unit commitment and dispatch only results in financial settlements for the first 24 hours of the week. Units that are self-committed are not eligible for make-whole payments.

4:00 p.m. of the day before operations. At this time, PJM posts the day-ahead hourly schedules and LMPs, based on the day-ahead market-clearing dispatch. These prices and schedules are used for the settlement of the day-ahead financial market.

- The hourly day-ahead dispatch and LMP calculations are performed using a least-cost security constrained dispatch program that models all normal and single contingency limitations.

[76] Make-whole payments are made for operating reserves.

- A difference between PJM and New York is that in PJM the day-ahead prices are based on a dispatch to meet bid load and the operating reserve objective, and do not reflect PJM's load forecast.

4:00 – 6:00 p.m. of the day before operations. This is the PJM balancing market offer period.

- During this time, market participants can submit revised price offers, but only for units not selected (even in part) in the first commitment. The revised offers are used in both the balancing market unit commitment and for the real-time dispatch.

- Market participants may also submit new basic transactions, changes to existing transactions and changes to self-scheduled unit output during this time period, although the final deadline for these changes occurs 20 minutes before the real-time dispatch.[77]

- At the end of this step, all *physical* supply and demand offers and physical transaction information is fed back to the RSC system for the second unit commitment.

6:00 p.m. of the day before operations. At this time, the balancing market offer period closes and PJM performs the balancing market unit commitment based on updated offers, updated unit availability information, and updated PJM load forecast information.

- The focus of the balancing market commitment is reliability and the objective is to minimize only start-up and no-load costs for any additional resources that are committed to meet PJM's forecast load.

[77] If a market participant withdraws a transaction that causes a ramp, PJM will notify the market participant if there is a ramp violation. If the market participant is able, it must modify its other transactions to correct the violation. If it cannot, PJM will go back in timestamp order to determine the last company that adversely affected the ramp.

- The second unit commitment does not decommit any units that were committed in the first unit commitment. However, units may request to be decommitted if they are not needed for reliability.[78]

- Any price-based transactions that were accepted day ahead are locked in in the second unit commitment, unless changed by market participants.

- The optimization in the second unit commitment is done over seven days, and may lead to the commitment of a unit with a minimum run time that spans two days.

- Ramping limits are observed in the second unit commitment and dispatch.

- At the end of the second unit commitment, the OI dispatcher informs generators of any changes to the first unit commitment. The dispatchers have some discretion in deciding which schedules to change following the second unit commitment. Generators are assumed to follow the schedules that are released at 4:00 p.m. unless they are notified by telephone of a schedule change following the second unit commitment.

- No LMPs are calculated at this step and there is no financial settlement associated with the schedules resulting from the second unit commitment. The balancing market settlement occurs based on the prices and quantities in the real-time dispatch. Schedule changes ordered after the second unit-commitment roll over into the real-time dispatch.

6:00 p.m. to Operating Day.

[78] Units can request to be decommitted at any time, including the rebid period and before the real-time dispatch. When this occurs, the dispatcher will typically make reliability run to see if unit is needed.

- Following the second unit commitment, PJM allows only fixed schedule changes; this means that it does not allow any changes to price bids.[79] It allows new transactions, changes to existing transactions (MW schedules) and changes to self-scheduled unit output. Generators on dispatch are permitted to change to "must-run" status. All of these changes, called Hourly Transactions, can be made without penalty with 20-minutes notice, assuming use of the EES for external transactions. Any change to a transaction will assign a new timestamp to the transaction. Internal ramp priority and curtailment priority consider the timestamp.

  Ramping is made available for new hourly transactions on a first-come, first-serve basis. New schedules are not permitted to violate ramping constraints. If ramping room becomes available as a result of an hourly scheduling change, PJM will assign the room on a first-come, first-serve basis to new hourly transactions.

- PJM may experience difficulty if there are large changes to external schedules that occur less than 60 minutes before the hour. If imports are cut, it may cause PJM to be short of ramping capability. Similarly, if exports are cut, ramping capability may become available to support economic transactions that may fail to be bilaterally scheduled so close to the dispatch.

- Throughout the operating day, PJM may perform supplemental unit commitment runs, as necessary, based on updated PJM load forecasts and updated unit availability information. If PJM is short of generation during this time, it may turn on CTs. PJM continually re-evaluates and revises the generation schedule, and sends out individual generation schedule updates as required.

- Control area reliability-based scheduling processes occur throughout the day prior to the operating day. PJM dispatchers develop a 2-hour operating plan that includes a

[79] There is no rebidding in PJM between the second unit commitment and the real-time dispatch. In particular, there is no hour-ahead market in which new price bids are considered and scheduled as in New York's BME. Balancing market bids are considered on an on-going basis in the 5-minute dispatch.

complete security analysis. This allows them to evaluate whether congestion is developing and, if necessary, to make plans to cut non-firm transactions that are not willing to pay congestion. The transactions require 20-minute notification before they are cut. PJM does not provide advance notification because to do so would divulge market-sensitive information.

E. Maritime Market

1. Overview

The Maritime Market is a single control area, comprising New Brunswick Power ("NB Power"), Nova Scotia Power ("NS Power"), and Maritime Electric Company on Prince Edward Island ("PEI"). NB Power's 345 kV transmission system forms the center of this system and includes interconnections with the other two maritime utilities, with Hydro Quebec, and with ISO-NE through a synchronous tie with Northern Maine. NB Power is the control area operator, and the transmission control center is in Marysville, near Fredericton, New Brunswick.

Total installed capacity in the interconnected Maritime Provinces is approximately 6120MW, including independent power generation. Although recent Maritime annual peak loads have been around 5100MW, these peaks occur in the winter. During ISO-NE's annual (summer) peaks, the Maritime peak loads are only approximately 3500MW, thus providing ample opportunity for diversity sales between neighboring regions.

While the interconnected Maritime Provinces have not formally opened transmission access, a number of steps have been taken in this direction:

- In 1998, NB Power voluntarily filed an open access tariff for Through and Out Point-to-Point transmission. The tariff is similar in many respects to the pro-forma point-to-point tariff issued with FERC's Order No. 888.

- Limited wholesale access will be granted in near future. As one example, PEI total requirements contract with NB Power will end later this year. After its expiration, PEI will be allowed to purchase its power from one or more suppliers and arrange with NB Power for delivery.

- In 1999, NB Power functionally unbundled its transmission operations from its generation and merchant functions to provide an independent operator of its system.

Further changes in both New Brunswick and Nova Scotia are awaiting definitive policy changes by the responsible provincial governments. Until such changes occur, no transmission access has been granted to either IPPs or large industrial customers. The utilities anticipate such transmission access will be offered over the next few years, however, and there are active discussions for the construction of new merchant plants, especially with the recent completion of the Sable Island natural gas pipeline. Full retail access seems unlikely in the short term.

There is no liquid wholesale market in New Brunswick at present, and no transparent market-clearing spot price. All trade by Maritime utilities consists of bilateral sales. Internally, NS Power and NB Power routinely conduct "buy-sell" transactions, however, at their system borders. The most significant external trade consists of NB Power's exports to the U.S. Historically, NB Power has retained physical rights to all 700 MW of transfer capability on the existing 345 kV tie-line with Maine. However, when NB Power is not using all of its transmission to the U.S., it is available to others on a non-firm basis, and both HydroQuebec and NS Power have used the transmission tie for non-firm sales to New England. Most of the power imports into the Maritimes consist of purchases by NS Power and NB Power from HydroQuebec. As discussed later in this section, there is very little transmission capability to permit purchases from New England.

2. Products

Historically, the Maritime utilities have purchased and sold capacity, energy, and some operating reserves among themselves and with HydroQuebec and NEPOOL. Until recently, ancillary services were not offered as a separate product. However, NB Power's open-access tariff now provides for sale of three ancillary services, including:

- Scheduling, system control and dispatch service;
- Reactive supply and voltage control from generation sources service; and
- Energy imbalance service.

Although spinning and non-spinning reserves are not specifically mentioned, the Maritime Utilities are accustomed to providing such products.

3. Transmission

Transmission capability between the Maritimes and ISO-NE is usually constrained in both directions. NB Power and ISO-NE are connected by a single 345 kV transmission line from Keswick to Orrington. North to south transfers on this line are limited to 700 MW.

South-to-north transfer capability between ISO-NE and the Maritime Provinces is even more severely limited. Such transfer capability, which is calculated by ISO-NE in real time, is often 0 MW, but may be as high as 100-200 MW when NB Power's Point LePreau nuclear unit (650 MW) is out of service.[80]

Construction of a second 345 kV intertie between New Brunswick and Maine is being seriously considered. Such a line would increase transfer capability in both directions. Current projections indicate that north-to-south transfer capability would increase by 200 to 300 MW.

4. Scheduling

Because there is no formal market structure in the Maritimes, each utility schedules its own resources to meet its own native load requirements. All wholesale transactions are bilateral and are typically scheduled at least a day ahead. However, because there are relatively few transactions taking place, changes in these transactions can be made up to an hour ahead, or even less than an hour ahead, if acceptable to the two parties. Bilateral exchanges between the Maritime utilities and HydroQuebec are handled similarly to internal transactions.

All external schedules with ISO-NE are made by Maritime utilities' New England customers, most of whom are market participants in ISO-NE. Because these consuming entities must adhere to ISO-NE scheduling protocols, all arrangements between the Maritime utilities and their customers must take place *prior to* the established ISO-NE deadlines.

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[80] The major constraint on deliveries from south to north is the contingency in which the LePreau nuclear unit is suddenly lost from service, immediately leading to a 650MW change in net interchange with New England.

Chapter III. Real-Time Interregional Congestion Management

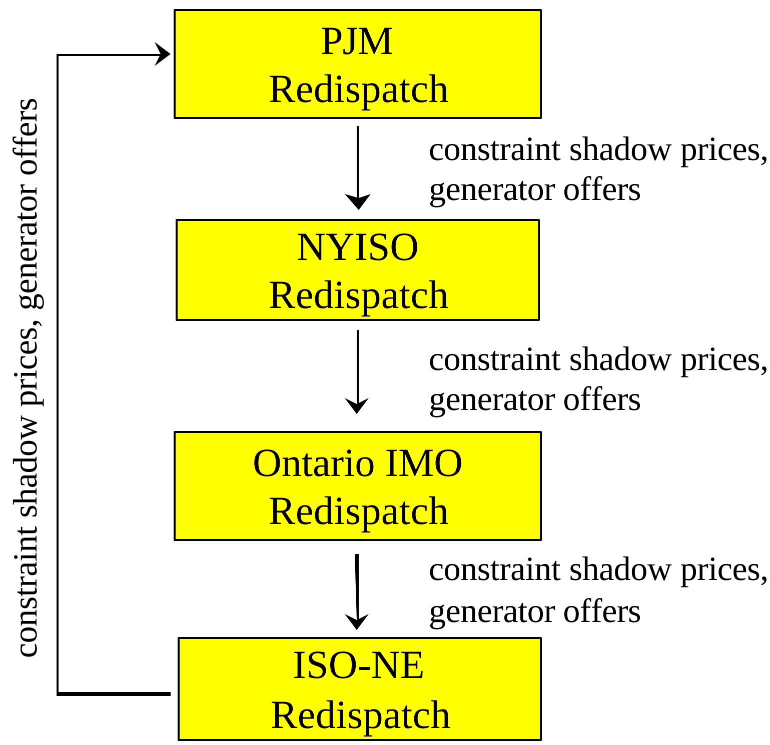
The four Northeast ISOs (ISO New England, New York ISO, Ontario IMO and PJM) have been engaged since 1999 in developing a mechanism for real-time interregional congestion management. Under this mechanism, each ISO would continue to monitor the transmission constraints within its control area and redispatch its units to manage these constraints. In addition, however, the ISOs would exchange information on constraint shadow prices and generation offers for the purpose of interregional congestion management.

The proposed process would operate sequentially, with each ISO redispatching its resources to manage its transmission constraints, taking account of any impact that that redispatch would have upon binding constraints in the adjacent regions. In addition to being able to redispatch its own internal resources to manage congestion, however, each ISO would also be able to take advantage of supply offers from generators in adjacent control areas in managing its internal constraints.[81]

The process would be iterative, because each redispatch would change flows and impact constraint shadow prices and could move up supply offer curves. Thus, the process might begin with a PJM dispatch as shown in Figure 2. PJM would then provide ISO-NE, NYISO and Ontario IMO with constraint costs for constraints within PJM and incremental supply offers available for interregional dispatch from PJM generators. New York would then redispatch its generation to meet its load, taking account of the PJM constraint costs and generation supply offers. New York would then provide the other ISOs with constraint costs for its constraints and incremental supply offers from its generators available for inter-regional dispatch. This process would then continue through Ontario, ISO-New England and then repeat through PJM until the solutions converged.

[81] See Andrew Ott, "Interregional Transmission Congestion Coordination Example."

Figure 2



This conceptual framework was tested during 2000, in particular with respect to the convergence properties of the solution. The results of these convergence studies were satisfactory, and PJM and NYISO[82] have proposed to move ahead to prepare for an operational test of the interregional redispatch mechanism.[83] While the interregional redispatch mechanism is moving rather rapidly towards implementation, the redispatch mechanism as proposed is only a first step towards interregional real-time coordination. It has been proposed that this mechanism would initially be utilized only to solve transmission constraints that an individual ISO cannot solve with its own resources.[84]

[82] PJM and NYISO are the logical parties for the initial test since they are already operating LMP-based pricing and dispatch systems.

[83] See PJM, "Interregional Transmission Congestion Coordination," December 4, 2000.

[84] This triggering mechanism obviously has the potential to lead to anomalies. Suppose, for example, that in one interval the NYISO could solve the Central East constraint, but must accept very high bids in order to do so and the price difference across Central East is $900/MWh. Then suppose that in the next interval the NYISO could not solve the constraint with its own resources, triggering the interregional redispatch mechanism, and enabling the NYISO to solve the constraint at a cost of only $100/MWh. In this situation, more severe congestion would result in lower prices in the congested region.

Once the successful operation of the interregional redispatch mechanism is established, however, the mechanism could be triggered in all periods in which transmission congestion exists, rather than only those in which an individual ISO is unable to manage congestion. Moreover, the interregional redispatch mechanism could ultimately be triggered in every interval to, in effect, schedule net interchange among the Northeast ISOs on a 5-minute basis corresponding to the real-time dispatch. If the interregional redispatch process were fully implemented in this manner, interregional schedules would cease to have any physical meaning within the Northeast and would become purely financial. There would, however, continue to be a need for mechanisms to coordinate interchange with control areas bordering on the expanded Northeast market as well as to take reliability actions that fall outside the 5-minute dispatch framework, such as starting 30-minute gas turbines. These operating details have not yet been worked out.

The implementation of the interregional redispatch mechanism will also require resolution of a variety of settlement issues. First, as generation could be dispatched in one control area to manage a constraint in another control area, the settlements process will need to provide for assigning the cost of this interchange. Second, and less obviously, each control area could potentially capture in its internal charges for generation and load a portion of the congestion rents attributable to constraints in the adjacent control areas. Revenue adequacy of each ISO vis-a-vis its day-ahead settlements will require procedures to track the collection of congestion rents and appropriately reassign these rents.

The interregional real-time redispatch mechanism is, in an important sense, the real-time counterpart of the combined day-ahead market evaluated in this study. Moreover, as discussed more fully in Chapter IV, there is a fundamental sense in which the full implementation of the real-time interregional redispatch mechanism must precede implementation of a combined day-ahead market. Absent a real-time interregional redispatch mechanism and prices calculated based on such a dispatch, the interregional schedules determined in a combined day-ahead market process, upon which reliability analyses were premised, might not be economically sustainable.

Chapter IV. Development of a Combined Day-Ahead Market

A. Benefits and Costs of a Combined Market

The development of a combined day-ahead market in the Northeast is intended to address seven broad areas for improvement. First, the combined market is intended to facilitate electricity trading across a broad region of the Northeast, and in particular to enable more consistent scheduling of interchange transactions within the Northeast, in turn leading to a more efficient and less volatile regional electricity market. Second, the combined market is intended to facilitate inter-ISO congestion management. Third, the combined market is intended to support reserve sharing mechanisms across the Northeast ISOs that will lead to a more efficient (lower cost) and reliable market. Fourth, the combined market is expected to broaden the relevant market within which generators compete to supply power, easing market power concerns. Fifth, the combined market is intended to reduce transaction costs for market participants that participate in multiple markets. Sixth, the combined market is intended to provide improved mechanisms for hedging transmission congestion in day-ahead markets. Seventh, the combined market could provide a mechanism for reducing future software costs.

At the same time, the feasibility study is intended to identify and evaluate potential costs associated with such an expanded day-ahead market, potentially including: incremental software costs; possible changes to existing market rules, including scheduling and settlement deadlines; additional solution time for the day-ahead market software; cost shifting across control areas; reduced rather than increased reliability; increased rather than reduced potential for gaming; and compatibility with the current ISO market designs.

The potential benefits are outlined below, and both the benefits and costs are discussed in Section IV B in the context of the alternative approaches to the development of a combined market.

1. Improve Scheduling of Inter-Change Transactions

The difficulty of coordinating interchange schedules across control areas has been a persistent problem for the ISOs and market participants. Under the current market structures, a market participant that wishes to schedule a day-ahead transaction between two ISOs must schedule both: (1) a withdrawal from the exporting ISO and (2) an injection into the importing ISO. If there is no transmission congestion on the import or the export interface, the market participant may structure the offers that it submits to the unit commitment and scheduling processes of the two affected ISOs so as to assure the scheduling of these transactions without regard to the market price of injections and withdrawals at the importing and exporting locations in the two ISOs.

Many market participants, however, wish to submit price-sensitive bids to import and export power to these day-ahead unit commitment and dispatch processes, so as to manage the congestion-related prices that they pay for any transactions that are scheduled day ahead, as well as to avoid buying power at very high prices in one control area for resale into another control area at much lower prices. This approach recognizes the reality that if exports or imports are expected to be highly profitable for an individual market participant submitting a schedule, they will likely be highly profitable for many other market participants, and the collective schedules submitted may exceed the available transfer capacity. If transmission limits on imports or exports are binding, not all schedules can be accommodated, and transmission usage must be allocated in some manner.

Problems can arise in this circumstance from the operation of separate unit commitment and scheduling processes in neighboring ISOs. In particular, there is a potential for the separate day-ahead unit commitment and dispatch processes of the importing and exporting ISOs to treat the same transaction differently, so that it is scheduled in the day-ahead market process of one ISO but not in the day-ahead market process coordinated by the other ISO. This potential for mismatches and schedule imbalances can be undesirable from the standpoint of market participants because of the risks they may incur with unbalanced positions, or the costs they incur to mitigate these risks. An important objective of a combined day-ahead market for the Northeast is to enable market participants to avoid such unbalanced schedules and the associated need to hold capacity out of the various day-ahead unit commitment and scheduling processes in order to hedge these unbalanced schedules.[85]

This potential for schedule imbalances can also be undesirable from the standpoint of the affected ISOs from a reliability perspective, in that these imbalances give rise to the possibility that day-ahead markets may clear, yet the total resources actually committed day ahead may not be sufficient to meet the forecast load plus ancillary service requirements.[86] This potential for reliability surprises is currently managed in New York and PJM, and soon will be managed in NEPOOL, by the financial commitments associated with day-ahead schedules. While this mechanism appears to be working well in both PJM and New York, there is a residual potential for miscalculations with reliability consequences.

2. Facilitate Inter-ISO Congestion Management

At present the Northeast ISOs have a very limited ability to use resources in adjacent control areas to manage congestion within their own control areas. The MOU process is developing procedures that will be used to provide such inter-control area congestion management in real time. This real-time inter-ISO congestion management will be limited, however, to the resources that are available following the day-ahead commitment and does not provide a mechanism for resources to be committed or decommitted day ahead so as to help manage congestion.

[85] For example, market participants that are uncertain as to whether they will emerge from the day-ahead unit commitment and dispatch processes with balanced inter-ISO transaction schedules may find it necessary to hold back generation from the unit commitment and dispatch process so as to hedge these risks.

[86] Thus, if a market participant seeking to buy power in NEPOOL to sell in New York succeeded in scheduling the import into New York but failed to buy power in the NEPOOL day-ahead unit commitment and dispatch process, there would be load in New York to be supported by exports from NEPOOL, for which no capacity was committed in NEPOOL to support.

One advantage of a combined day-ahead market would be to permit generation to be committed within one ISO in order to better manage congestion within another ISO. This opportunity is likely to be particularly relevant between Ontario and New York for management of internal Ontario constraints, and between New York and NEPOOL for management of New York's Central East Constraint. In addition, a combined day-ahead market encompassing New York, NEPOOL and PJM would permit more effective management of the relationship between flows over Central East in New York, PJM's Eastern Interface, and NEPOOL's imports from Quebec.

Thus, internal Ontario resources, New York imports, and Eastern Interconnection loopflows all cause congestion on internal Ontario constraints. Adjustments to New York unit commitment and schedules could be used to relax the constraint, reducing the overall cost to Ontario consumers of congestion on this interface. Similarly, NEPOOL generation is electrically East of Central East and could be committed as an alternative to generation in Eastern New York, thereby reducing the cost to Eastern New York consumers of managing congestion on the Central East interface.

Finally, centralized coordination of the New York Central East interface, PJM Eastern interface and HydroQuebec imports in day-ahead markets could permit NEPOOL to schedule additional imports in these markets under some conditions, reducing the cost to NEPOOL consumers. It should be noted that the HydroQuebec interaction is fundamentally different than the other coordination problems, as the transmission limit into NEPOOL depends on the level of flows over constraints in PJM and New York. Coordinating these elements of the day-ahead unit commitment would likely require development of additional algorithms to implement the interrelationship, and the empirical magnitude of the benefits are uncertain. It is possible that the actual likely benefits would still not warrant the cost of modifying software and additional solution time, even were a combined day-ahead market implemented within the Northeast.

A related but somewhat distinct element of congestion management is the potential need to take account of differing congestion impacts resulting from transactions scheduled across controllable lines between control areas linked by both open ties and controllable lines (either PAR controlled AC lines or DC interconnections). This issue arises with respect to schedules across the controllable lines between New York and NEPOOL and between New York and PJM. Absent consistent pricing systems, market participants may not have an incentive to schedule the efficient level of transactions on these lines.[87]

3. Facilitate Reserve Sharing

The Northeast ISOs currently include substantial reserve margins in their day-ahead unit commitment. Total 30-minute reserves committed day ahead by the New York ISO are 1800MW and another roughly 3000-3450MW of reserves are committed by ISO-NE. The Ontario IMO sets an operating reserve requirement of at least 1350MW, of which 900MW is supplied by 10-minute reserves.

ISO-NE and NYISO are currently working out procedures within NPCC for real-time reserve sharing. The efficiency and reliability of this procedure would be improved if it could be included in the day-ahead unit commitment process. This would ensure that low cost capacity in one region that is able to provide reserves for the adjacent region would be committed day ahead.

4. Expand the Market

A combined day-ahead market that more tightly links generation and load across control areas may materially reduce market power concerns as well as increase market efficiency. The market rules currently required to coordinate the transfer of energy between control areas can serve to create market boundaries that limit competition even when transmission constraints are not binding, thus artificially reducing the scope of the market within which generators compete. This reduction in market size may exacerbate

[87] This concern does not arise if the schedules on the controllable lines are determined by the ISOs, rather than by the market participants.

market power problems and require the implementation of market power mitigation rules that would be unnecessary in a broader market.

Moreover, separate real-time dispatch of generation in adjacent control areas with looped interconnections is likely to require the application of conservative measures of inter-control area transfer capability in scheduling transactions both in day-ahead and hour-ahead scheduling processes. Larger transfer capabilities might therefore be made available by coordinating the dispatch of generation first in real time (under the MOU real-time redispatch) and eventually day ahead (through a combined day-ahead market), thus expanding the level of competition between generators in the separate control areas.

5. Reduce Transactions Costs

A combined day-ahead market holds the potential to reduce market participant transactions costs in several respects. These include reductions in the time and manpower required to schedule and confirm inter-ISO transactions, reductions in the time required to train personnel to participate in Northeast markets, and reductions in the costs of errors arising from differences in terminology and scheduling interfaces.

6. Improve Inter-Regional Congestion Hedging Mechanisms

A combined day-ahead market in the Northeast also holds the potential to allow improved mechanisms for market participants to hedge congestion in three respects. First, under the current separate congestion management, pricing and hedging mechanisms of the Northeast ISOs, there is a potential for a market participant to implicitly pay the congestion costs associated with a particular constraint more than once. Second, differences in congestion modeling across the day-ahead unit commitment and scheduling processes of the Northeast ISOs can create incentive problems for both daily scheduling and transmission investments. Third, a combined day-ahead market in the Northeast could, depending on its structure, provide the basis for the sale of a single set of point-to-point financial rights in a coordinated regional auction. This would both reduce transaction costs for market participants and permit the award of FTRs for transmission expansions affecting transfer capability in more than one control area.

The first of these problems can occur if two neighboring ISOs are running separate, simultaneous day-ahead unit commitment and dispatch processes that enforce the same inter-control area transmission constraints. If the two ISOs separately manage the same inter-control area constraint using a bid-based pricing mechanism, market participants may pay twice, once in each day-ahead market, for congestion across a single constraint. Thus a market participant might pay the cost of congestion in both day-ahead unit commitment processes, or in the day-ahead unit commitment process of one ISO and the hour-ahead or real-time process of the other ISO, for a single transaction. This double payment may have the effect of causing a market participant to realize a low price for selling energy into market B from market A, while also paying a high price to schedule an export withdrawal out of market A. In order to hedge against congestion costs, a market participant must therefore buy two sets of congestion hedges for the same transmission constraint. A combined day-ahead market design could eliminate this problem.

Conversely, if the two ISOs separately manage the same inter-control area constraint using their own sets of physical transmission and ramping rights, there would be a potential for market participants to pay the cost of congestion twice, once to buy the physical transmission right in the first control area and then to buy these rights in the other control area.

The redundant pricing of the inter-control area constraints also could exacerbate the problem with inconsistent scheduling of imports and exports that is discussed above. Thus, market participant X might be scheduled to import into market B because it bid a lower price than did market participant Y for its injections, but market participant Y, rather than X, might be scheduled to export from market A into market B, because it was willing to pay a higher price than was X. These inconsistencies could also arise if nonprice allocation mechanisms (such as physical rights) were used to allocate transmission usage.

Apart from the potential for double payment of congestion costs, a second problem related to congestion pricing and hedges is that there can be differences in the representation of inter-control area transactions in the day-ahead market processes of the various ISOs. Thus, at present PJM models transactions from PJM to New York based on schedules from PJM to NYISO East and from PJM to NYISO West, while the NYISO models transactions from a single PJM bus into New York. These differences in modeling are tied to the issue of pricing for controllable lines and can affect the incentives of market participants to schedule transactions on controllable lines and to make investments in transfer capacity on controllable lines. Although the development of a consistent pricing framework for transactions scheduled over controllable lines could be implemented independently of a combined day-ahead market, it would be helpful to implement such a pricing mechanism on a consistent basis across the day-ahead and hour-ahead settlement processes in the Northeast.

A combined day-ahead market that includes a combined pricing and scheduling step, and a mechanism for regional collection of congestion costs is a prerequisite for the implementation of a regional financial rights auction. One of the benefits of such a regional auction would be greater ease in hedging inter-regional term transactions, as the hedges for a transaction from Ontario to NEPOOL could be acquired in a single financial rights auction. Another benefit of such a combined regional auction would be an improved ability to award financial rights to market participants making transmission investments that affect transfer capability in more than one region. While it would be feasible to recognize these benefits in separate auctions, it would be simpler within a single combined auction framework.

A transition to a combined regional financial rights auction would also reduce ISO implementation costs and aid investment in more sophisticated auction mechanisms, such as developing software to implement a simultaneous feasibility test for FTR options. The

FERC has directed ISO-NE to develop FTR options, but the simultaneous feasibility test for the award of these options is complex.[88] A combined regional financial rights auction would provide a framework for sharing the costs associated with developing the required algorithms and software.

7. Reduce Future Software Costs

There is a potential in moving to some version of a combined day-ahead market to reduce the overall software costs that would otherwise be incurred by the Northeast ISOs in developing, maintaining, and improving several separate software programs for coordinating the separate day-ahead market processes in the separate control areas.

B. Alternative Structures for a Combined Market

There are two broad approaches that can be taken to developing a combined day-ahead market and achieving the benefits outlined above. One broad approach would be to move towards a combined day-ahead market implemented by an RTO through a single unit commitment and scheduling process that encompasses the entire Northeast. The other broad approach would be to move towards a combined day-ahead market implemented through separate day-ahead unit commitment and scheduling processes within an overarching framework that enables market participants to implement a single combined day-ahead market solution. For each of these two polar approaches, there are a number of variations that borrow one or more elements from each. The approaches considered in this study include:

- Separate simultaneous unit commitment and scheduling;
- Separate sequential unit commitment and scheduling;
- Separate iterative unit commitment with combined scheduling;

[88] FERC order, Docket No. EL00-62-000, et. al. issued June 28, 2000, p. 33. FTRs not satisfying the simultaneous feasibility criterion would not be hedged by the congestion rents collected by the ISO in charging locational prices. Such financial options could be sold by market participants able to hedge the option with generation or trading assets.

- Separate unit commitment with data exchange and combined scheduling;
- Hierarchical unit commitment with combined scheduling;
- Single unit commitment with combined scheduling;
- Single unit commitment with separate scheduling.

The most fundamental difference among these approaches is between those with and without a combined scheduling and pricing mechanism. The approaches including a combined day-ahead scheduling and pricing mechanism require as a prerequisite implementation of the MOU process for a coordinated real-time economic dispatch.[89] The approaches based on day-ahead prices and schedules determined by individual control areas, on the other hand, do not require implementation of a coordinated real-time dispatch process to succeed, but these approaches would also work better in such an environment, as the real-time inter-regional dispatch would resolve hour-ahead transaction scheduling issues.

Finally, there is a brief discussion of the potential for implementing day-ahead markets based on a single unit commitment process and joint determination of interchange schedules, but with day-ahead prices and schedules determined by individual control area constraints. This approach would implement a single day-ahead market that would not require implementation of a coordinated real-time dispatch process, but would give rise to a number of other problems.

It is important to keep in mind in evaluating mechanisms for implementing a combined day-ahead market that the purpose of the day-ahead unit commitment and scheduling processes coordinated by ISOs is to manage reliability problems on a day-ahead basis, particularly those relating to common goods, the transmission grid and reserves. Each Northeast ISO has developed day-ahead unit commitment and scheduling processes and software that are designed to manage the reliability problems facing that particular ISO. Each ISO's day-ahead unit commitment software and processes have to varying degrees

[89] Absent a mechanism for coordinating the real-time dispatch across control areas, schedules that were feasible in a day-ahead market based on a combined dispatch might not be economic or feasible in real time.

been streamlined by ignoring reliability constraints that do not materially affect that ISO's unit commitment, given the resource mix available within that control area.

For example, control areas able to rely on quick start units to provide all of their 10- and 30-minute reserve requirements may not need to take account of these reserve requirements in their unit commitment process or may be able to account for them in a simplified manner. Control areas that must, on the other hand, at the margin commit steam units to meet 10- and 30-minute reserve targets either for the control area as a whole, or for regions within the control area, will need to take account of these requirements in their day-ahead unit commitment decisions.

The requirements of the day-ahead unit commitment process can also be affected by the control area market structure. For example, a control area normally able to meet 10- and 30-minute reserve requirements with off-line quick start units may also need to take account of these requirements in its day-ahead unit commitment decisions if the market structure permits the economic withholding of these quick start units, requiring that the ISO be able to substitute on-line steam units for withheld quick start units. A potentially important implication of a combined day-ahead market for the Northeast coordinated through a single day-ahead unit commitment and scheduling process is that the single software and market process would need to be able to manage all of the reliability constraints of all of the ISOs included within the combined market.

This is the source of the fundamental tension underlying the choice of a combined day-ahead market mechanism. At one extreme one has individual control area day-ahead unit commitment processes that are customized to address the reliability needs of that control area. Thus, PJM has a process and software tailored to PJM reliability needs, NYISO has a process and software tailored to New York reliability needs, the IMO has a process and software in the process of being tailored to Ontario reliability needs, and ISO-NE has a process and software tailored to NEPOOL reliability needs. If a combined day-ahead market for the Northeast is to be implemented through a single market process and a single unit commitment software package, then that process and software must be tailored to meet the combined reliability needs of NEPOOL, New York, Ontario and PJM.

There is therefore a potential that in order to address the combined reliability needs of multiple control areas, a single unit commitment process and its associated software would need to address more reliability constraints, as well as more units and a larger network, than any of the individual unit commitment processes. Much of the discussion in the section below is directed at evaluating potential mechanisms for simplifying the combined day-ahead market software, by avoiding the need to analyze every regional reliability constraint within a single unit commitment process and software model. These tensions are clearly illustrated in the alternatives considered below. Approaches 1 and 2 avoid the need to combine the unit commitment processes and software, permitting each control area to continue to utilize day-ahead unit commitment processes that are optimized for that control area's individual needs. These approaches would achieve a combined day-ahead market through better coordination of these separate day-ahead unit commitment processes. At the other extreme, Approach 6 would rely upon a single unit commitment process, which would need to be able to accommodate the reliability needs of all of the participating control areas. In between these extremes, Approaches 3, 4 and 5 are different possible approaches to continuing to rely to some degree on individual control area unit commitment software and processes, but within a framework in which prices and schedules are ultimately determined based on regional dispatch and governed by regional reliability constraints.

Each of these alternative approaches is discussed below.

1. Separate Simultaneous Unit Commitment and Scheduling

a) Overview

One approach to the coordination of a combined day-ahead market in the Northeast would be to continue to administer separate unit commitment and dispatch processes within each of the ISO control areas but to change the timing of these unit commitment processes to maintain simultaneous bid and schedule submission deadlines, and roughly simultaneous schedule posting times. This approach would place the burden for creating a coordinated day-ahead market on the actions of market participants acting as arbitrageurs, rather than on the ISO or RTO unit commitment software. This approach is similar to the current market mechanisms, except that it envisions altering market closing times to be approximately the same across the control areas in the Northeast.

The posited advantage of this approach is mainly to allow the NYISO unit commitment process to start later in the day. This later start would allow generators and loads to submit bids to the NYISO day-ahead market early in the morning rather than late the night before as is often the case with the current 5:00 a.m. bid deadline. This change in the bid deadline would permit reliance on more accurate load forecasts, potentially improving reliability and reducing costs. Another advantage of this approach is that it might require relatively limited software changes relative to the current mechanisms, although even this depends on precisely how it would be implemented. The fundamental limitation of this approach to coordinating a combined day-ahead market in the Northeast is that it gives rise to great complications in scheduling inter-control area transactions in the presence of congestion or price sensitive supply and demand offers. Moreover, the approach is not conducive to inter-control area congestion management or reserve sharing.

b) Discussion

<u>Congestion Management and Interchange Scheduling</u>

A critical feature of this approach is that because each ISO would schedule interchange transactions separately and simultaneously, it would inevitably give rise to the possibility that a transaction might be scheduled by one of the affected ISOs but not by the other. The first manner in which this inconsistency could arise is through the operation of the congestion management system.

If the ISOs relied on a financial (i.e. bid-based mechanism) to allocate transmission usage and both ISOs enforce the inter-control area constraint in their day-ahead unit commitment and scheduling process, there would be no way for market participants to rationally bid so as to be scheduled in both the delivering and sending market in the presence of congestion. If market participants bid extremely low in the import market and extremely high in the export market, the winner could end up paying congestion costs twice, in excess of the value of the transaction. Alternatively, one market participant could end up scheduling transmission out of the supplying market and another market participant could end up scheduling transmission into the receiving market.

The ownership of financial transmission rights hedging the import and export constraint would mitigate this problem, but only if there were a single set of financial transmission rights, jointly offered by the two ISOs, that hedged congestion costs for inter-change transactions in both markets, and there were no outages that reduced transfer capability. With a single set of such financial rights, the rights holder could submit low bids into both markets to assure that it was scheduled, and its ownership of the financial rights would hedge the scheduler against congestion costs.

Even this approach only mitigates, not eliminates, the underlying problem. Such a market would operate much like a bilateral market with physical rights. Market participants seeking to reliably schedule transactions would need to acquire the financial right in a bilateral transaction and could then bid so as to ensure that the transaction was scheduled in both control areas. Although withholding would not be possible, market participants using the separate unit commitment and scheduling processes to schedule transactions could not be assured of being scheduled in both markets and would incur the risk of being scheduled in one market but not the other.

Alternatively, both of the affected ISOs rather than relying upon a financial congestion management system, could rely upon a system of physical transmission rights to allocate capacity. Such a single set of physical transmission rights for allocating schedules between the control areas in the day-ahead market, combined with a single priority system for curtailments on each interface and an accompanying set of physical ramping rights for each control area in each hour, could enable market participants scheduling bilaterals between control areas to submit transactions that would either be accepted in both markets or neither market as a result of transmission congestion. Physical rights systems, however, give rise to the potential for withholding, as has been the case with NEPOOL's physical rights system.[90] Moreover, if each ISO allocated its own set of physical transmission rights, there would be potential for gridlock as well as withholding.[91]

Thus, the congestion management problem can be solved under this approach to a combined day-ahead market using either a financial or physical transmission rights system, but only by moving to a single set of transmission rights for transactions between the control areas.

Interchange Scheduling and Day-Ahead Energy Markets

A second manner in which the problem of inconsistent schedules would emerge under this approach, whether based on a financial or physical rights system for congestion management, would be if market participants, including the holders of physical or financial transmission rights, sought to submit price sensitive bids to buy or sell power in the day-ahead unit commitment and scheduling processes.

It is inherent in the provision of such price sensitive bids that the market participant submitting the bid will not know at the time it is submitted whether it will be accepted. This means that a market participant submitting price sensitive supply or demand offers to one control area cannot simultaneously submit to the other affected control area the bids or schedules required to produce a consistent schedule, because it does not know

[90] The potential for adverse effects from withholding would be mitigated if any physical rights expired in the day-ahead market, so that capacity not scheduled day ahead would be available for scheduling in the hour-ahead scheduling process.

whether the price sensitive transaction will clear in the day-ahead scheduling process in which it was submitted.

In this circumstance, there would be a potential, under systems based on either financial or physical transmission rights, for a transaction to clear in one market but not in the other.[92] There is no scheduling strategy that would enable a market participant submitting such a price sensitive demand or supply bid in the day-ahead unit commitment and scheduling process of one market, to assure that it would emerge from simultaneous separate day-ahead scheduling processes with consistent schedules across the affected control areas. This potential for inconsistent schedules is not incidental, as the ability of market participants to submit price sensitive supply and demand bids for exports, i.e. to offer to supply more power when the price is high and to buy more power when the price is low, is critical to the ability of external loads and generation to limit the exercise of market power within the day-ahead markets of the individual control areas.[93]

Market participants could resolve schedule inconsistencies arising as a result of such arbitrage activities in the day-ahead markets by adjusting their day-ahead schedules in the hour-ahead scheduling processes as illustrated in Figure 3, so that schedules become consistent in real time. Thus, if market participant B's supply offer cleared in the day-ahead unit commitment and scheduling process of market 1, but it did not schedule exports in the simultaneous day-ahead unit commitment and dispatch process of market 2, it could resolve the inconsistency by submitting an export schedule in the hour-ahead scheduling process of market 2. While such a process would provide a way for market participants to arrive at consistent schedules, it would give rise to further complexities. First, a mechanism would still be needed to assure that consistent schedules emerge from the hour-ahead scheduling process. Second, the day-ahead unit commitment could be inconsistent with the final real-time schedules.

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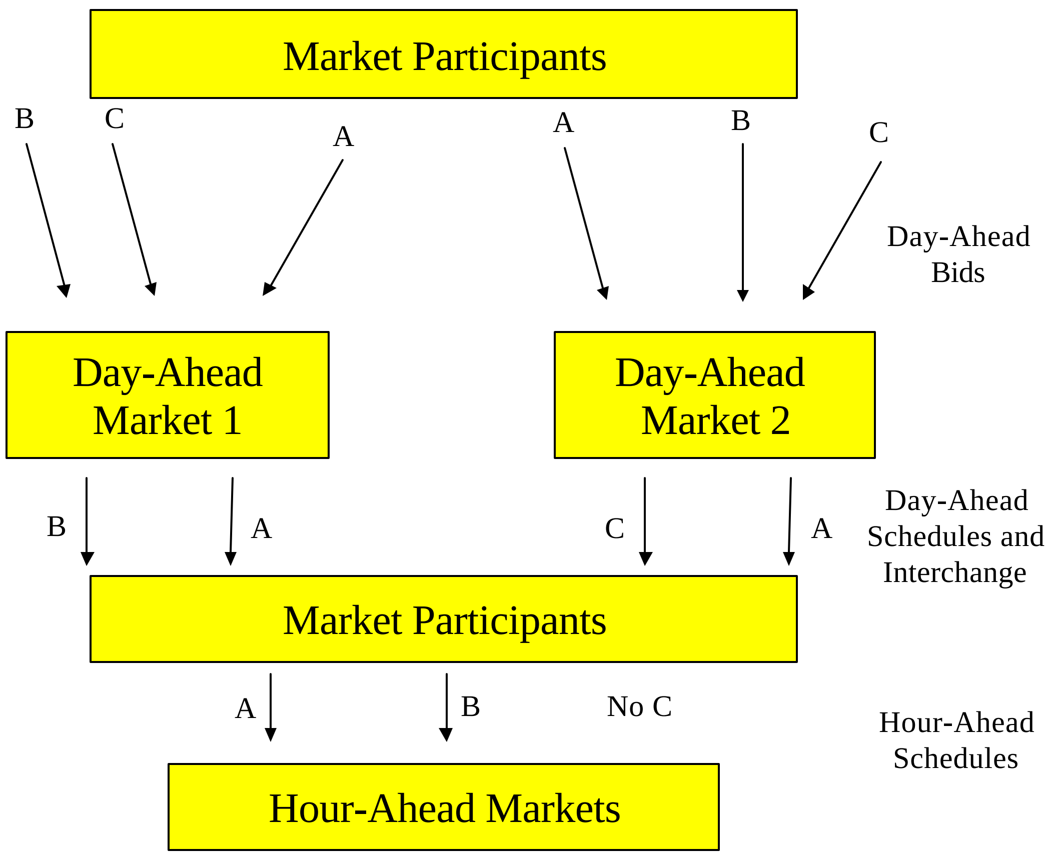
[91] If two sets of physical rights were required to schedule each transaction, either rights holder could withhold the capacity from use, and a mere inability to trade would also effectively withhold the capacity.
[92] Another consideration is the potential for withholding of physical transmission rights from the day-ahead market to dramatically reduce the competitiveness of the day-ahead market in one or both of the affected control areas.

Figure 3



Consider the first issue of a mechanism for ensuring that consistent hour-ahead schedules emerge from the scheduling process. Market participants with unbalanced positions in the day-ahead interchange schedules could submit hour-ahead schedules to provide sources and sinks for their unbalanced export and import schedules or, alternatively, cancel the transactions for unbalanced sources and sinks. For example, consider a market participant that has an import schedule accepted in the day-ahead unit commitment and dispatch process of one ISO, but does not have a corresponding export schedule from the source control area,[94] such as transaction B in Figure 3. The market participant could either: (1) schedule an export from the source control area in the hour-ahead scheduling

[93] This applies to the potential for the exercise of market power in the day-ahead market by either generation or load.
[94] This situation could arise either because the market participant submitted an offer to buy that failed to clear in the day-ahead unit commitment and dispatch process in the source control area, or because the

process or (2) cancel the import schedule into the receiving control area in the hour-ahead scheduling process. In either case, the market participant would pay the appropriate balancing market price in the real-time settlements process of the affected ISOs.

There is, however, a potential for market participants to attempt to rationalize the inter-change schedules in a way that violates transmission constraints. Under a financial mechanism for allocating transmission usage, it is possible for one market participant to submit high bids to market 1 to ensure that it is scheduled to export, while another market participant would submit low bids to market 2 to ensure that it is scheduled to import. This potential for inconsistent hour-ahead schedules could be avoided under a system of physical transmission rights in the hour-ahead markets, but only at the cost of allowing for the withholding of transmission rights in the hour-ahead market and likely greatly reducing participation in the day-ahead interchange market.[95]

A further limitation of such a process for avoiding inconsistent schedules in the hour-ahead markets when congestion exists is the need to take account of the role of the hour-ahead scheduling process in managing real-time reliability. In addition to submitting hour-ahead schedules to balance day-ahead schedules, market participants in New York currently provide the NYISO with hour-ahead offers for price sensitive exports that the NYISO uses to provide counter-flow when transmission capability is reduced in real time, and hour-ahead supply offers for imports that can be used to meet load or maintain

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accepted bid was an arbitrage offer that was only accepted because of unusually high prices in the receiving control area, and thus the market participant could not anticipate that the offer would be accepted.

[95] Thus, if a single set of physical transmission rights between markets 1 and 2 were allocated and were required in real time as well as day ahead to schedule interchange between markets 1 and 2, this would ensure that whoever held this transmission right could schedule a transaction between markets 1 and 2 in the hour-ahead scheduling process (subject to a curtailment mechanism if transfer capability was reduced). Thus, if B held this right in the example above, it would be ensured of being able to schedule its transaction from market 2 in the hour-ahead process. There are, however, two difficulties with this approach. The first difficulty with this approach is that it creates the potential for withholding of the physical transmission rights from the hour-ahead scheduling process so as to exercise market power. Thus, if the physical transmission right were held by firm D that had a large long position in generation in market 2, firm D could withhold this transmission capability from the market to drive up the price in market 2. The withholding problem would be somewhat mitigated by adopting physical rights that would be in effect only in the day-ahead market. The second problem is that the mere need to acquire physical transmission rights in order to schedule transactions in real time would drive market participants out of the day-ahead market and limit supply offers to those made by the holders of the physical rights. This problem arises because only the physical rights holder will be able to capture any value associated with real-time transactions.

reserves in a shortage situation. These market mechanisms for scheduling transactions hour ahead are not workable with simultaneous separate hour-ahead scheduling processes, because the market participant submitting such an offer to market 1 would not know at the time the offer is submitted whether it will be accepted, and therefore does not know whether to schedule the transaction in the hour-ahead process of market 2. Once again, there is no course of action that the market participant could take that would assure that it would emerge from the scheduling process with consistent schedules across control areas, but now the problem is in the hour-ahead rather than day-ahead scheduling process.

Three approaches have been identified for addressing the problem of inconsistent hourly schedules arising form price sensitive bids within the simultaneous market approach. One possible approach to reconciling inconsistent hour-ahead schedules would be to allow market participants to submit conditional schedules that would be price sensitive supply or demand offers in one control area and price taking schedules in the second control area if scheduled in the first control area. This approach would allow the second control area to be aware of the schedule but could require that each control area evaluate a wide range of contingent net interchange schedules, not knowing which schedules might be accepted by the other control area.

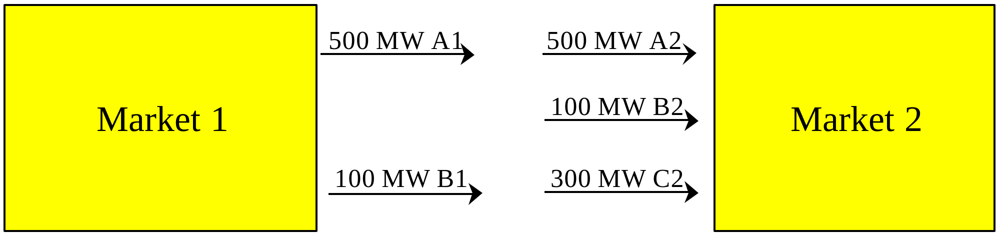
A second approach to avoiding inconsistent schedules arising from price sensitive bids would be to simply eliminate price sensitive supply and demand offers in the hour-ahead scheduling process. Thus, market participants could be required to submit fixed schedules in the hour-ahead process that would flow regardless of prices. This would entail a shift to a reliance on real-time emergency purchases to maintain reserves and meet load by the affected control areas, as they would not have the opportunity to schedule additional energy in the hour-ahead scheduling process.

Finally, the full implementation of the real-time interregional redispatch process would eliminate these problems, as the need for hour-ahead interchange transaction schedules within the region would be obviated by the real-time redispatch process.[96] Thus, inconsistencies in day-ahead schedules would have financial consequences for the market participant, but the inconsistencies would not hinder the scheduling of real-time flows as these would be determined by a real-time interregional redispatch that would ensure consistent schedules and efficient arbitrage within the Northeast during the hour.

The second difficulty with this approach to a combined day-ahead market is the potential for inconsistencies between the unit commitment and real-time schedules. Importantly, while the hour-ahead markets can be used to rationalize unbalanced schedules created in the day-ahead unit commitment and dispatch process to ensure that all imports are matched by an export in the checkout process, unbalanced schedules would nevertheless exist in the day-ahead unit commitment process and the resources required to support the exports might not be committed in the day-ahead unit commitment process of the exporting control area. This potential is illustrated in Figure 4 in which 600MW of exports have been scheduled from market 1 to market 2 and 900MW of imports have been scheduled into market 2 from market 1. The difference is 300MW of transaction C2 that cleared as supply in market 2 but failed to clear as an external load in market 1. The market participant that submitted this transaction would be financially committed to transaction C2, but the unit commitment in market 1 would not have included capacity to support this transaction.

Figure 4

Day-Ahead Schedules



[96] By full implementation of the MOU redispatch process is meant an implementation which utilizes the redispatch algorithm on a regular basis during the hour (perhaps less frequently than the intra-control area redispatch), as opposed to an implementation under which the MOU redispatch is utilized only in extraordinary circumstances.

The financial obligations associated with day-ahead schedules in the NYISO, PJM and prospectively NEPOOL markets ensure that the market participants making such supply offers recognize their potential financial exposure. The pricing system thereby incents them not to make supply offers that they would not be able to hedge themselves against, i.e. to not offer resources that they will be unable to deliver. Thus, since the entity responsible for transaction C2 would not know at the time it submitted bids to markets 1 and 2 whether its supply offer would be accepted in market 2, it might hedge its potential financial exposure if the offer were accepted through ownership of a unit that could be committed in market 1 to support the export to market 2 or through ownership of a unit in market 2 that could be committed to cover the short position in the day-ahead market. The limitation of this approach to inter-regional scheduling is that the need to maintain hedges requires that some capacity be held out of the market to preserve these hedges. Thus, the market participants submitting the inter-regional supply offers would maintain their hedges by submitting generation bids that in effect hold this hedging capacity out of the day-ahead markets until it is known which inter-regional schedules have cleared in which markets.

Suppose, for example, that firm C submitted a supply offer into market 2 to supply 300MW of power from market 1 at a price of $100/MWh or higher, intending that if the bid is accepted to schedule the export from market 1 in the hour-ahead scheduling process. If firm C does not own generation in either market 1 or market 2, the firm is exposed to the possibility of being required to cover this forward sale by purchasing power at very high real-time prices. If firm C has 300MW of generation located in market 1 that it could commit to support this transaction, then this generation can provide a hedge for the transaction, but only if firm C in effect holds this generation out of the day-ahead unit commitment and scheduling process in market 1. If firm C offered this capacity into market 1 and counted on the same capacity to hedge supply offers made into market 2, firm C could end up having sold 300MW of power in market 1 and also sold 300MW of power in market 2, with only 300MW of capacity to cover 600MW of sales. This risk is avoided if the market participant in effect holds its capacity out of market 1 through a very high bid, or schedules a bilateral export transaction from its generation in market 1 that it would cancel if the power sale did not clear in market 2.

As observed above, a limitation of hedging strategies based on capacity in the exporting control area is that in order to offer supply in the day-ahead unit commitment and scheduling process for market 2 (the destination control area), the generation owner in effect has to hold this capacity out of the day-ahead unit commitment and scheduling process for market 1 (the source control area), even if the supply offer ends up not clearing in market 2. This withholding of capacity in order to provide hedges would not be material if one market were clearly likely to be short while the other market were clearly likely to be long, but it requires that the generation owner offer the capacity into one or the other of the day-ahead unit commitment and scheduling processes. If the generation owner misjudges supply and demand conditions, the capacity could be offered and go unused in the lower priced market, while being withheld from the higher priced market, driving up prices in that region. This is the crux of the problem created for this hedging strategy by separate day-ahead unit commitment and scheduling processes, that if market participant expectations are inaccurate, resources may be misallocated and result in prices that are too low in one region and too high in another.

An alternative hedging strategy can be based on generation within the receiving control area. In this case, as well, however, the capacity that provides the hedge cannot be offered in the day-ahead unit commitment and dispatch process of the control area in which the capacity is located, nor could the capacity providing the hedge be used to offer capacity into other adjacent markets. If the supply offer from the adjacent control areas is priced below running cost of the generation providing the hedge, however, then absent congestion between the external supply source and the generation providing the hedge, any time the external supply offer is not accepted, the generation providing the hedge would also not have been scheduled had it been offered. In this circumstance there would be no cost associated with the hedge. If there is congestion, however, then holding capacity out of the day-ahead unit commitment and dispatch process of the receiving control area may have a material opportunity cost and the withholding could inflate prices in the receiving control area. The potential for misallocated capacity and distorted prices exists therefore under either hedging strategy.

In addition to this potential for the hedges motivated by the two settlement system to cause capacity to be held out of the aggregate Northeast market, there is also a potential for mistaken market participant expectations to cause them to make supply offers that they would not be able to cover in real time. While the financial commitments associated with two settlement systems assure that market participants engaged in inter-control area arbitrage will attempt to hedge their positions by only offering capacity that they can deliver, there is a potential for market participants to mis-read the supply situation in the source control area, and offer export supply in a day-ahead market from a control area that would be unable to meet its own load in real time.[97] These shortage situations should be identified by high day-ahead prices, and unhedged loads should be motivated to seek additional resources through bilateral contracts, but there is a potential for reliability surprises, particularly if each ISO evaluates its ability to meet forecast load based on scheduled imports and assuming, that it would cut exports as required to meet control area load.

Other Features

Another significant limitation of the simultaneous separate unit commitment and scheduling approach is that inter-ISO congestion management would be accommodated in the day-ahead unit commitment only to the extent that it was recognized in the schedules submitted by the market participants, and would not be unit specific.[98] Thus, congestion management would be limited to whatever impact was associated with a general increase or decrease in net interchange with the other control area, and would not extend to the commitment and scheduling of generation at particular locations within one control area to relieve congestion within another control area.

[97] This happened between PJM and New York on May 8, 2000. Export supply from PJM was sold into New York's day-ahead market, but the PJM OI did not allow the transactions to flow in real time because of shortages in PJM. In fact, New York made emergency energy sales to PJM in real time.

In addition, this approach would not provide a mechanism for the ISOs to coordinate the day-ahead markets so as to jointly meet reserve requirements, since the unit commitment processes would be running simultaneously but separately.

Finally, this approach to interregional unit commitment and dispatch does not directly resolve the problem of multiple congestion charges. Rather, it would require that the multiple congestion charge problem be mitigated through the development of a single set of financial or physical congestion rights.

c) Benefits and Costs

The advantages of the separate simultaneous approach appear to be first, that it would not entail development of new unit commitment and dispatch software for New York and PJM. Second, by retaining a completely separate unit commitment process for each control area, this approach would minimize cost shifting, particularly of uplift, between control areas. Third, this approach would not entail any changes in the day-ahead unit commitment processes of the various control areas that would increase the duration of that process. Fourth, it would permit all control areas in the Northeast to run unit commitment and scheduling processes during the late morning or early afternoon.

This approach would not, however, provide a very effective mechanism for resolving inconsistent interchange schedules, particularly among control areas seeking to allow price sensitive supply and demand bids. This would be a particular problem prior to full implementation of the interregional real-time redispatch process. Moreover, the approach has the potential for giving rise to real-time reliability surprises. The financial commitments underlying the day-ahead markets are designed to minimize this potential but would thereby lead to the withholding of capacity to hedge interregional supply offers. Finally, the approach offers little or no potential benefits through coordination of day-ahead commitment with respect to either congestion management or reserve sharing.

[98] Inter-ISO congestion management might be somewhat improved by adopting improved pricing systems for transactions scheduled by market participants over controllable lines.

2. Separate Sequential Unit Commitment and Scheduling

a) Overview

Another approach to improving interchange scheduling in the day-ahead market would be to operate separate day-ahead unit commitment and dispatch processes within each ISO but within a structured sequence that would enable the separate processes to operate much as if they were a single process. That is, the day-ahead unit commitment and scheduling process for control area 1 would close and post results prior to the deadline for submitting bids and schedules to the day-ahead unit commitment and scheduling process of adjacent control area 2. This would enable any market participant whose import or export bid or schedule was accepted in the day-ahead scheduling process of control area 1 to submit the other end of the schedule to the day-ahead unit commitment scheduling process of the other control area involved in the transaction.

b) Discussion

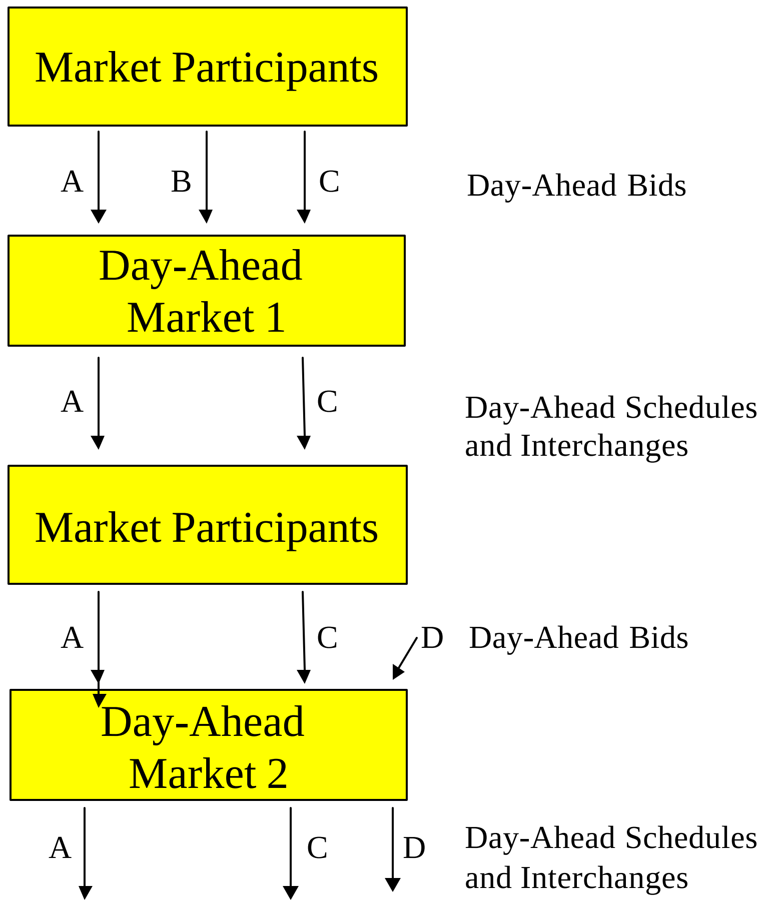
The intent of this approach would be to avoid the complexity of implementing a single Northeast-wide day-ahead unit commitment and scheduling process, while allowing market participants to better manage their import and export schedules by sequencing the deadlines for bid submission and schedule posting among the neighboring ISOs. Moreover, the geographic relationships among the Northeast ISOs would permit the implementation of a system in which the New York unit commitment and scheduling process operated either first or last, with all of the other processes operating simultaneously, as all schedules between the control areas operated by the other ISOs must go through New York.

Timeline:

- Step 1: Market participants submit offers to buy and sell to unit commitment and scheduling process of Market 1.
- Step 2: Market 1 operates its unit commitment and scheduling process and posts accepted day-ahead schedules.
- Step 3: Market participants submit offers to buy and sell to unit commitment and scheduling process of adjacent Market 2. These offers will reflect the bids previously accepted in Market 1. Thus, if an export were scheduled in Step 2 from Market 1, then the market participant would know to bid aggressively to schedule the matching import to Market 2 during Step 3.
- Step 4: Adjacent Market 2 operates its unit commitment and scheduling process and posts accepted day-ahead schedules.

Figure 5

Separate Sequential Processes



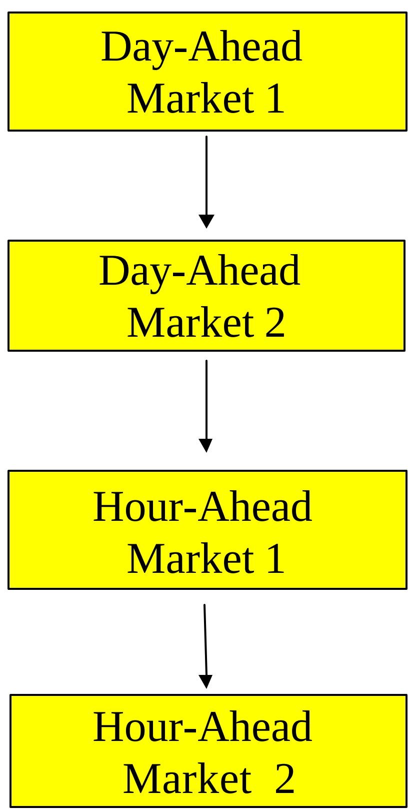
As illustrated in Figure 5, this approach to market coordination would enable market participants to submit consistent bids and schedules across the ISOs because they would know which schedules had been accepted in adjacent control areas. Thus, suppose market participants A, B, and C submitted offers to buy power in control area 1 for export to control area 2. Under this approach, the market participants would know which offers had cleared in the day-ahead unit commitment and scheduling process of control area 1, prior to the time they needed to submit offers to market 2. Thus, if offers A and C cleared the day-ahead scheduling process in control area 1, these market participants could submit low priced offers to supply energy into the unit commitment and scheduling process of control area 2, greatly increasing the likelihood that the transactions would be accepted.

Extending the Sequencing to Hour-Ahead Scheduling

As noted, full implementation of this approach would have two additional elements. First, the sequencing of the day-ahead scheduling processes would be extended to the hour-ahead scheduling processes as shown in Figure 6. Thus, suppose that in addition to market participants A and C bidding to sell energy into the day-ahead market coordinated in control area 2, market participant D also submitted an offer to sell power into control area 2 from control area 1 (as shown in Figure 5). Market participant D, however, would not have purchased power in the day-ahead scheduling process for control area 1 for export to control area 2. This inconsistency could be resolved by market participant D in the hour-ahead scheduling process for control area 1, after which, there would be complete and consistent schedules for exports from control area 1 to control area 2 by market participants A, C and D.

Figure 6

Sequenced Market Approach



Interregional Financial Rights and Scheduling Rights

A second additional element of the sequenced market approach would be some changes to the financial rights mechanisms for hedging congestion between control areas, so as to create a single set of transmission and scheduling rights between adjacent control areas. These changes would be necessitated by the potential for double charges for congestion which can also be illustrated with Figure 5. Suppose that the export demands of market participants A and C completely exhausted the transfer capability between control areas 1 and 2, so that the price at control area 1's external proxy bus for control area 2 exceeded the price within control area 1 and exceeded market participant B's willingness to pay. The price paid by market participants A and C to purchase for power export to control area 2 would then include congestion rents across the control area1/control area 2 interface.

Market participants A and C could again face competition, however, in selling into control area 2, with market participant D also submitting bids into the day-ahead unit commitment and scheduling process of control area 2 to sell power into control area 2 from control area 1. If market participants A and C were underbid by market participant D, inconsistent schedules would again arise.

Although this is less likely than under the first approach precisely because the first market would already have cleared, there is still a potential for multiple entities to attempt to schedule transactions into the second control area. Market participants clearing schedules in the first market (A and C in the example) could bid very low in the day-ahead unit commitment and scheduling process of control area 2, to ensure that they are scheduled to sell into control area 2. These low bids in competition with the supply offers of market participant D and others could, however, exhaust the transfer capability between control area 1 and control area 2, depressing the external proxy bus price for control area 1 below the price within control area 2 in control area 2's day-ahead scheduling process. Thus, the price at the control area 2 external proxy bus for control area 1 would reflect the congestion rents across the control area1/control area 2 interface. This would mean that market participants A and C would pay these congestion rents twice.[99]

This problem of double congestion charges would be avoided if the sequenced market approach to interregional scheduling were joined with a combined auction for a single set of inter-regional financial transmission rights between each of the adjacent control areas. These transmission rights would only hedge congestion across the external constraints.[100]

Importantly, these financial rights (IFTRs – interregional FTRs) would settle against the price of the inter-regional constraint in the first day-ahead unit commitment and dispatch process, i.e. market 1 in Figure 6. The entities acquiring schedules across this constraint in market 1 would acquire a financial scheduling right that would settle, however, against the price of the inter-regional constraint in the second day-ahead unit commitment and scheduling process, market 2 in Figure 6. Similarly, the entities acquiring schedules across this constraint in the day-ahead unit commitment and scheduling process of Market 2 would acquire a financial scheduling right that would settle against the price of the inter-regional constraint in the first hour-ahead scheduling process, Market 1 in Figure 6. Finally, the entities acquiring schedules across this constraint in the hour-ahead scheduling process for market 1 would acquire a financial scheduling right that would settle against the price of the inter-regional constraint in the second of the hour-ahead scheduling processes, that of market 1 in Figure 6.

The operation of this system is illustrated in Table 7. It is assumed that in the day-ahead unit commitment and dispatch process of control area 1 there is excess demand for exports to control area 2 and transfer capability is exhausted. As a result, the internal control area 1 price would be $40/MWh but the price would be $50/MWh at the proxy bus for control area 2, set by the marginal demand bid at this bus that was accepted. The IFTRs would

[99] The sale of financial transmission rights hedging these congestion costs by the ISOs for control areas 1 and 2 would not resolve the problem, because market participants A and C would need to buy two sets of financial transmission rights to get across one constraint.

therefore settle at the $10/MWh price of the constraint and the holders would receive this amount in the settlement process. The market participants scheduled in the control area 1 unit commitment and dispatch process would then have scheduling rights over the constraint between control area 1 and control area 2. To ensure they were scheduled to sell into control area 2, they could submit low bids into the day-ahead scheduling process of control area 2 that would exhaust the transfer capability from control area 1 into control area 2. These bids would set a price of, for example, a $10/MW at the control area 2 external proxy bus for control area 1 as shown in Table 7, despite a price of $80/MW within control area 2. These market participants would therefore sell their power into control area 2 for only $10/MW in the day-ahead scheduling process of control area 2.

These market participants would be hedged, however, by the scheduling rights they received when they were scheduled out of control area 1. These scheduling rights would entitle them to be paid the $70/MWh of congestion costs between control area 1 and control area 2, in the control area 2 day-ahead scheduling process. Taking this payment into account, the sellers would net $80/MW for selling energy into control area 2.[101]

Table 7
Sequential Market Example

	Market 1			Market 2		
Market	Internal Price	Proxy Price	Constant Price	Proxy Price	Internal Price	Constant Price
Day-Ahead 1	$40	$50	$10			
Day-Ahead 2				$10	$80	$70
Hour-Ahead 1	$50	$150	$100			
Hour-Ahead 2				-$20	$80	$100
Real-Time	$60				$75	

[100] Any hedges of congestion costs associated with internal control area transmission constraints that would be managed by a control area in its real-time dispatch would be acquired from the pertinent control area.

[101] Moreover, if another seller dramatically underbid them, driving the day-ahead price of energy at the control area 2 proxy bus for control area 1 to -$100, the entities holding the scheduling rights into control area 2 from control area 1 from the first step in the sequential process would collect even larger congestion rents on their scheduling rights.

The market participants scheduled in the day-ahead unit commitment process of control area 2 would then have scheduling rights over the control area 1/control area 2 interface in the hour-ahead process of control area 1 the next day. In the example portrayed in Table 7, the market participants ensure that their schedules flow by submitting high sink price bids for exports from control area 1 to control area 2, in the hour-ahead scheduling process of control area 1 driving the control area 1 proxy bus price for control area 2 to $150, while the internal price would be only slightly higher than in the day-ahead market. The market participants scheduled to sell into control area 2 from control area 1 in the hour-ahead process would therefore have to pay $100/MWh for transmission from control area 1 to control area 2, but this payment would be hedged by the scheduling right they would hold from the day-ahead unit commitment and scheduling process of control area 2 of the preceding day.

Finally, the hour-ahead scheduling process of control area 2 would be run, with the entities having schedules out of control area 1 submitting negative decremental bids to assure that they are scheduled into control area 2. Since the entities that would been scheduled by control area 1 to export to control area 2 would be the only entities whose transactions could pass check out if scheduled by control area 2, there would normally be no congestion at the proxy bus in this final scheduling step.[102] In any case, the entities scheduled in the hour-ahead scheduling process of control area 1 would have scheduling rights in the hour-ahead scheduling process of control area 2 that would hedge them for congestion costs.

It is important to understand that these settlements of scheduling rights as described above would only change ownership of the financial transmission rights across the external interface and would not necessarily extinguish positions in the internal energy market. Suppose, for example, that market participant A bought power at the external proxy bus for control area 2 in the day-ahead unit commitment and scheduling process of control area 1 at a price of $50/MWh as shown in Table 7. Further suppose that market

[102] The exception would be if transfer capability was reduced between the time that control areas 1 and 2 operated their hour-ahead scheduling processes.

participant A had submitted an offer to sell into control area 2 at $20/MWh in the day-ahead unit commitment and scheduling process of control area 2. With this bid, market participant A would not be scheduled to sell energy into control area 2 (because the market clearing price at the control area 1 proxy bus was $10/MW as shown in Table 7). Market participant A would, however, have acquired a scheduling right over the control area 1/control area 2 interface when it was scheduled in the day-ahead unit commitment and scheduling process of control area 1. This right would settle for $70 in the day-ahead unit commitment and scheduling process of control area 2. Market participant A would therefore have paid $50/MWh to control area 1 and would receive $70/MWh from control area 2.

Importantly, market participant A would have sold its scheduling right to export from control area 1 to control area 2, but it would still have a forward purchase of energy in control area 1 that would settle at the appropriate imbalance price. If there were no hour-ahead market, market participant A would settle its forward position in the energy market at the real-time price, which is $60/MWh for control area 1 in the example portrayed in Table 7. Thus, market participant A would have paid $10 for a scheduling right out of control area 1 day-ahead (the difference between the $40 price of energy at internal buses and $50 at the external proxy bus) which it would have sold in the day-ahead unit commitment and scheduling process of control area 2 for $70/MWh. In addition, market participant A would have paid $40 for energy within control area 1, which it would have sold in real-time for $60/MWh.

It should be apparent that under this approach to the development of a combined day-ahead market, most of the congestion rents associated with inter-control area constraints and payable to inter-regional FTR holders would likely be collected in the day-ahead unit commitment and scheduling process operated by the ISO that is first in the sequence. Congestion rents would also be collected in the subsequent day-ahead unit commitment and scheduling processes and hour-ahead scheduling processes, but most of these congestion rents would be payable to scheduling rights holders. The approach therefore envisions a mechanism for collecting the congestion rents associated with interregional constraints, regardless of the point in the market process in which they were collected, to fund payments to inter-regional FTR and scheduling right holders, and to allocate any residual between the transmission customers in the affected control areas.[103]

In sum, the sequential scheduling approach could be employed as described in the previous sections to rationalize schedules created in the day-ahead unit commitment and scheduling process to ensure that all import transactions are matched by an export transaction in the checkout process. This sequential scheduling mechanism could be accompanied by a system of auctioning inter-regional FTRs and defining and allocating scheduling rights that would enable market participants to hedge congestion risks and avoid double collection of congestion costs.

Inter-Control Area Arbitrage and Hedging

As noted previously, the sequential process for coordinating a combined day-ahead market in the Northeast is a process that fundamentally relies on market participants to analyze supply and demand conditions across the Northeast and appropriately allocate generation resources across control areas. If market participants lack the information required to coordinate the day-ahead market in this manner, then the sequential process will not operate as successfully as would a more centralized process.

Moreover, if the sequential approach were adopted it would be essential for the Northeast ISOs to work together to coordinate bid deadlines and posting times so as to provide a workable timeframe for market participants to schedule interregional transactions. It would also be desirable, and perhaps essential, to take steps to expedite the process of acquiring NERC tags during the sequential hour-ahead scheduling process. The hour-ahead sequential scheduling process would, in particular, be enhanced by the development of a common transaction interface for the submission of interregional

[103] A residual could arise from congestion across constraints for which financial transmission rights had not been sold. These collections would presumably be credited against the charges recovering the embedded cost of the transmission system. It would be less likely that there would be any residual following the auction of transmission rights options as discussed in Chapter V.

transactions and the exchange of scheduling status information between ISOs in the hour-ahead process. Finally, the approach would only work well if the ISOs were able to generally adhere to the sequence of posting times upon which the approach is premised.

Importantly, while the sequential scheduling approach leaves responsibility for inter-regional scheduling and arbitrage in the hands of the market participants, it reduces the need for market participants to hold capacity out of the unit commitment process for inter-regional hedging purposes. Because adjacent control areas would operate sequential (rather than simultaneous) unit commitment and scheduling processes, a market participant would be able to offer supply from uncommitted capacity for sale in an adjacent control area without needing to hold that capacity out of the unit commitment and scheduling process of the control area in which the capacity is located.

Thus, at the time bids for supply from control area 2 are submitted to the day-ahead unit commitment and scheduling process for control area 1, all generation capacity in control area 2 would still be available to hedge these supply offers (the generations owners would not have submitted any offers to the day-ahead unit commitment and dispatch process in control area 2). Thus, a supplier located in control area 2 could offer price sensitive supply into control area 1, knowing that it would be hedged by its uncommitted generation in control area 2. Moreover, the supplier would know whether these offers had been accepted when it came time to submit bids in control area 2. Conversely, at the point in time at which supply offers from control area 1 must be submitted to the day-ahead unit commitment and scheduling process in control area 2, the unit commitment and scheduling process for control area 1 would be complete, and any generation not committed in that process would be available to support sales into control area 2. Thus, a supplier located in control area 1 could bid capacity not scheduled in the day-ahead unit commitment and scheduling process of control area 1 into the corresponding day-ahead process of control area 2.

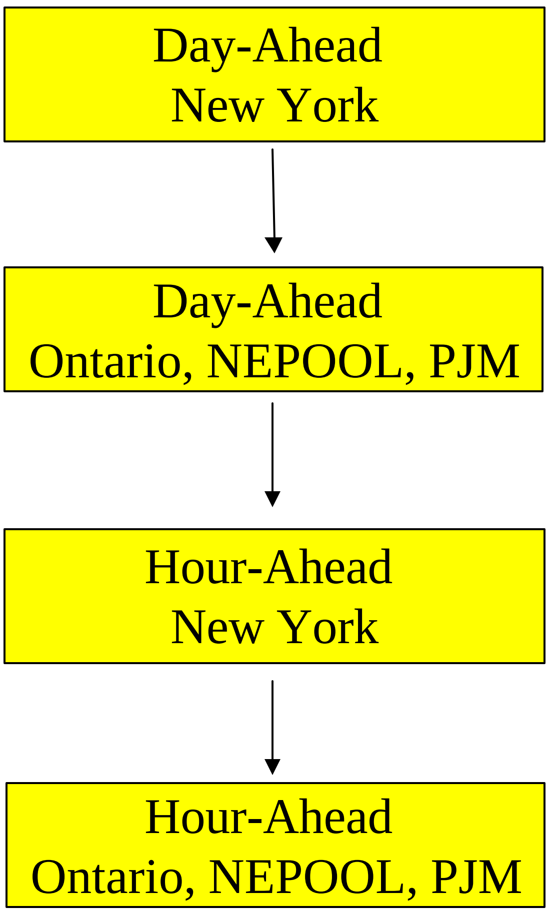
Nevertheless, while the sequential process avoids the need for generation owners to hold capacity out of the market to hedge their positions when offering supply for sale in adjacent control areas, generation owners with capacity located in the control areas that are second in the sequence must offer capacity for export before their own control area has run its day-ahead unit commitment and scheduling process. This could result in problems if they mis-assess the supply and demand balance within their control area. For example, suppliers in PJM offered substantial amounts of energy into the New York day-ahead unit commitment and scheduling process for May 8, 2000 and many of these offers were accepted. In fact, PJM was itself short and all of these exports were curtailed by PJM. This occurred prior to the implementation of PJM's full day-ahead market, but the existence of the day-ahead market does not eliminate the potential for this problem under the sequential approach.

Although the sequential approach enables market participants to submit hedged supply offers between adjacent control areas without withdrawing uncommitted capacity from the day-ahead scheduling process, this advantage of the sequential approach does not generalize to non-adjacent control areas if the sequential approach is used to create a combined day-ahead market encompassing more than two control areas. Suppose, for example, that the sequential process were applied to the Northeast as portrayed in Figure 8. The sequential approach to a combined market would work as described to coordinate transactions between New York and NEPOOL, New York and Ontario and New York and PJM.

Suppose, however, that a generator in PJM wanted to offer supply into NEPOOL. That supplier could submit bids in the New York day-ahead unit commitment and dispatch process to schedule a wheel through from PJM to NEPOOL. If the supplier were successful in scheduling transmission through New York, it could then submit supply offers into the NEPOOL unit commitment and dispatch process (which would open after the New York process was complete). The supplier would need, however, to submit bids for the offer of its capacity in the PJM market at the same time that it was submitting bids to sell energy in New England, and before it knew whether those bids would clear the market in New England. The PJM supplier would therefore need to withhold its capacity from the PJM market[104] to hedge the supply offers it was making in the NEPOOL market to avoid the possibility of selling the same capacity in PJM and NEPOOL.[105]

Figure 8

Sequenced Market Approach



[104] The PJM supplier would not need to literally withhold its generation from the market. It would offer its generation into the PJM market based on three part bids, but would submit a bid to buy power hedging its NEPOOL supply offer in the PJM day-ahead unit commitment and process. Between the sale of its generation and the purchase of power, it would not offer any net capacity into the PJM day-ahead unit commitment and dispatch process.

[105] This limitation of the sequential approach could in principle be addressed by adding rounds to the day-ahead market sequence. This would likely be workable for a control area such as Ontario with, at present, a very limited and fast clearing day-ahead market process. The Ontario process could be inserted between the other rounds of the day-ahead market process without greatly disturbing the timing of either of the other unit commitment and scheduling processes. It is not clear, however, that it would be possible to run three full scale day-ahead unit commitment and scheduling processes sequentially within an acceptable time frame. Adoption of such an approach would at least require some streamlining of these processes to remove steps needed largely for accounting purposes.

Potential Limitations and Elaborations

The basic sequential market process outlined above has three additional potential limitations on its ability to coordinate a combined day-ahead market for the Northeast. These include:

- Scheduling inconsistencies in the final hour-ahead scheduling process;
- Poor accommodation of inter-control area reserve sharing;
- Poor facilitation of inter-control area congestion management.

First, the control areas that go last in the sequence would not be able to use the hour-ahead scheduling process to manage real-time reliability. Thus, for example, market participants in New York currently provide the NYISO with hour-ahead supply offers for imports that can be used to meet load or maintain reserves in a shortage situation. These market mechanisms for scheduling transactions hour ahead would not be workable for the control areas going last in a sequential market system because the market participant submitting such an offer to market 2 would not know at the time the offer is submitted whether it will be accepted, and therefore would not know whether to schedule the transaction with market 1 in its hour-ahead scheduling process.

As under the simultaneous approach, one possible mechanism for reconciling such schedules would be to allow market participants to submit conditional schedules for uncommitted capacity to the hour-ahead scheduling process. Thus, these would be contingent bilateral schedules from control area 1 to control area 2 that would only be scheduled by control area 1 if the capacity were not scheduled to meet control area 1 load or reserves in control area 1's hour-ahead scheduling process. Moreover, these contingent schedules would be added after the solution of control area 1's hour-ahead scheduling process, would only be added until a constraint became binding and could not be utilized to relieve a constraint. This would ensure that the transactions could be cut in checkout without triggering additional cuts by causing other constraints to be violated.

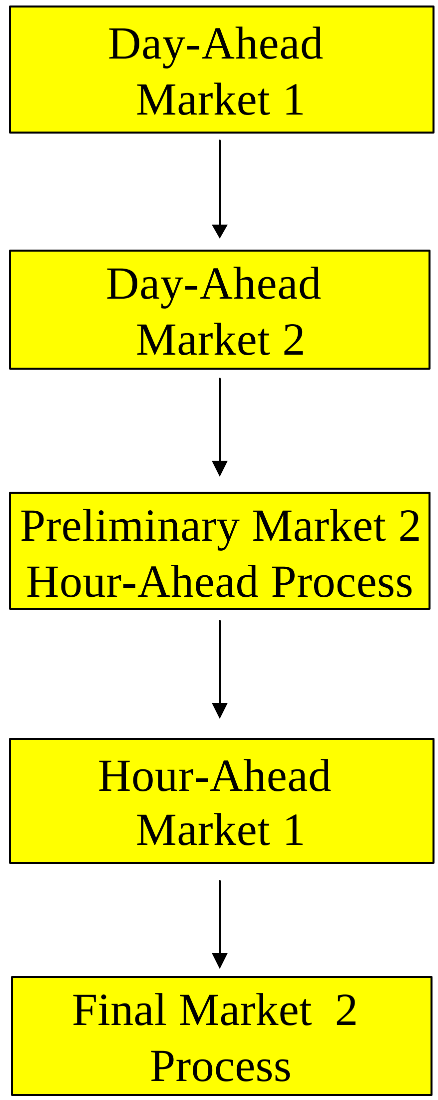
Under this mechanism, if control area 1 were not to schedule use of this capacity in its hour-ahead scheduling process, the bilateral transaction would be available for evaluation within the subsequent control area 2 scheduling process. If control area 2 accepted the supply offer, control area 1 would be aware of transaction and it would pass checkout. If control area 2 did not accept the supply offer, control area 1 would know that it was a contingent transaction and cutting the transaction in checkout would not have reliability consequences. If control area 1 did schedule use of the capacity in its hour-ahead scheduling process, the capacity owner would simply not submit the transaction to control area 2. One limitation of this approach is that it would only work between the control areas with the last hour-ahead scheduling process and those with earlier hour-ahead scheduling processes. It would not work between non-adjacent control areas with simultaneous hour-ahead scheduling processes.[106]

An alternative approach would be for the control areas going last in the hour-ahead scheduling process to eliminate sensitive supply and demand offers in their hour-ahead scheduling process and rely on real-time emergency purchases to maintain reserves and meet load. A variation on this approach would be for the control areas going last in the hour-ahead scheduling process to also run a preliminary scheduling process for price sensitive supply and demand offers prior to the scheduling process of the other control areas, as illustrated in Figure 9.

[106] As noted above, this problem could in principle be avoided by extending the sequence to include more than two rounds of hour-ahead scheduling processes, but this would likely not be workable within the limited time frame available for these hour-ahead scheduling processes. It is possible, however, that a streamlining of this process combined with faster computers could allow time for operation of three rounds of hour-ahead scheduling processes, which would alleviate this problem.

Figure 9

Expanded Sequenced Market Approach



Finally, as noted in the discussion of the first approach, the significance of this problem would be greatly reduced, if not entirely eliminated, by implementation of the real-time interregional redispatch process, as this redispatch would greatly reduce the significance of the hour-ahead scheduling process.

A further limitation of the sequential approach is that it does not fully accommodate coordination of the day-ahead unit commitment so as to jointly meet reserve targets. Because unit commitment is sequential, if market 1 were to under-commit reserves, it might be possible to make up the deficit in market 2 at a low cost, but it might not and this would not be known at the time market 1 completes its unit commitment and scheduling process.

A final limitation of this approach is that inter-ISO congestion management would be accommodated only to the extent that it was recognized in the schedules submitted by the market participants. The converse of these limitations with respect to reserves and congestion management is that because the unit commitment processes would be separate and uplift calculations would be separate, the uplift costs associated with individual control area transmission constraints, ancillary service requirements and local reliability criteria would be unlikely to be shifted between control areas.

c) Benefits and Costs

The advantages of this approach are similar to those of the first approach. First, it would not entail development of new unit commitment and dispatch software for New York and PJM. On the other hand, it would not obviate the need for any future software development costs for any of the Northeast ISOs. Second, by retaining a completely separate unit commitment process for each control area, this approach would minimize cost shifting, particularly of uplift, among control areas. Third, this approach would not entail any changes in the day-ahead unit commitment processes of the various control areas that would increase the duration of that process. Finally, the key advantages of this approach relative to the first approach are improved consistency of schedules in the day-ahead market and reduced withholding of capacity from day-ahead markets to hedge inter-control area arbitrage transactions.

The key disadvantages of the sequential approach are first, that it does not fully realize the advantages of a unified commitment and dispatch process. In particular, the approach offers little or no potential benefits through coordination of day-ahead commitment with respect to either congestion management or reserve sharing. Second, although the sequential approach is superior to the first approach with respect to its ability to avoid real-time reliability surprises resulting from import curtailments, there is still a potential for such surprises arising from transactions between non-adjacent control areas, although the financial commitments underlying the day-ahead markets are designed to minimize this potential. Third, the total duration of the day-ahead unit commitment process in the Northeast, from the time the first schedule is submitted to any control area to the time the last control area posts accepted schedules, will be longer, and potentially much longer, than under any of the other approaches. On the other hand, the duration from bid submission to schedule posting for each individual control area is likely to be the shortest under this approach.

3. Separate Iterative Unit Commitment with Combined Scheduling

a) Overview

A third approach to development of a combined day-ahead market for the Northeast would retain the separate day-ahead unit commitment processes of the individual control areas, with the commitment coordinated across control areas by the inter-regional supply and demand offers of market participants. Prices and schedules, however, would be determined in a final combined dispatch of all Northeast generation to meet all load. The separate control area unit commitment processes would reduce unit commitment solution time and reduce cost shifting, while the combined final dispatch stage would optimize inter-regional transactions.

This approach has two variations. The first is a single-pass approach, which would likely be highly vulnerable to gaming and increase, rather than decrease, the likelihood of reliability surprises. It is concluded that this variation does not warrant further consideration. The second is an iterative approach, which while perhaps appealing in the abstract would be very likely to require a substantial increase in the duration of the day-ahead unit commitment and scheduling process. Each of these variations is discussed below.

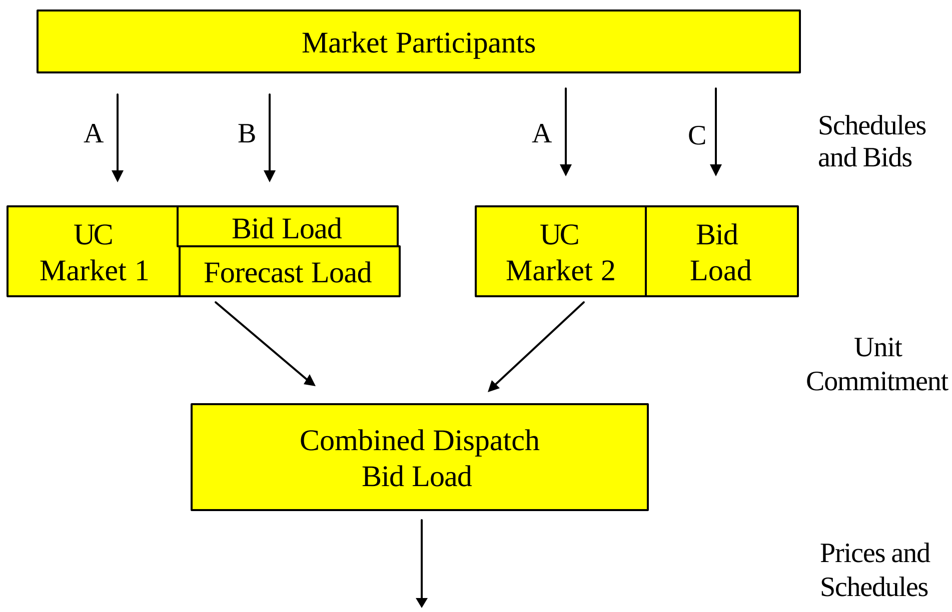
b) Discussion

Single-Pass Approach

The crux of the single-pass approach is that the individual unit commitment processes would be based solely on interchange bids and schedules submitted by market participants, followed by a regional combined price calculation and scheduling step as shown in Figure 10. The single pass approach would be relatively simple to implement but would have substantial problems that appear to render it unworkable.

Figure 10

One Pass Approach



The unit commitment step of the various control areas could include both a bid-load and forecast load pass prior to the price calculation step (as in the NYISO SCUC) or only a bid-load pass, as in PJM, with another forecast load pass following the combined dispatch step. The critical limitation of this approach is that the individual control area unit commitment processes would be based on the interchange schedules and bids submitted by the market participants which may not be: (1) consistent across control areas, or (2) consistent with the schedules determined by the combined price calculation and scheduling (i.e. dispatch) step. These inconsistencies could lead to extreme price levels in the combined day-ahead market that would not be warranted by the underlying supply and demand conditions.

First, if the inter-control area schedules used in the individual control area unit commitment step are based on the price sensitive bids of individual market participants, there is a potential for extreme solutions and for the final dispatch step to not even solve. Under this approach, market participants would submit bids to each control area for inter-control area exports and imports. If price-based inter-control area bids as submitted by market participants provide the basis for the unit commitment process, the export schedules and offers from control area 1 to control area 2, on which the unit commitment process for control area 1 is based, need not be consistent with the level of imports taken into account by the unit commitment process for control area 2. The result of this potential inconsistency would be that the level of imports from control area 1 assumed in the unit commitment of control area 2 may not be feasible given control area 1's actual unit commitment.[107]

Second, even if there is no actual infeasibility, there could be radical inconsistencies between the unit commitment solution and the prices determined in the combined dispatch step. If control area 1 did not actually commit enough resources to support the level of exports assumed by control area 2 in its commitment, prices could be dramatically higher in the combined dispatch step than in the unit commitment step of either control area 1 or control area 2. Moreover, there appear to be bidding incentives under this approach that would be likely to give rise to these kind of problems.[108]

[107] Under the current day-ahead market mechanisms, these inconsistencies are reconciled by market participants in the hour-ahead scheduling process. Day-ahead prices are in effect computed based on the assumption that market participants will commitment resources to support their interregional transactions. The one-pass method, on the other hand, would in effect solve the unit commitment problem assuming that market participants would commit resources to support their interregional transactions but then compute prices and determine schedules under the assumption that they would not commit resources to support their interregional transactions. This inconsistency in the assumptions underlying the unit commitment and the price determination is the fundamental potential problem with this approach.

[108] Thus, a generator in control area 1 could offer resources into control area 2 at a low price but submit no corresponding bids to buy from control area 1 for export or submit bids with very high reservation prices. The dispatch step could result in very high day-ahead prices for the generator's output scheduled in the day-ahead market, and any day-ahead financial obligation could be covered in real time by starting

These issues reflect a fundamental weakness of this approach in that the dispatch step operates upon unit commitments that would potentially be inconsistent with the dispatch and inconsistent with how the market participants offering interregional supply would have adjusted the unit commitments to support these transactions within a sequential market process. Moreover, because the inter-control areas schedules would be ultimately set in the dispatch step without regard to the supply and demand offers used in the commitment process, these supply and demand offers would not have any natural economic significance, which would invite gaming.[109]

There are a variety of possible approaches that could be taken to mitigate gaming incentives by, in some manner, attaching financial consequences to interregional supply and demand offers. The core of the one-pass approach, however, contains a contradiction between a unit commitment based on inter-control area supply and demand offers and a dispatch step that ignores these offers and simply meets regional load. Since the final dispatch step inherently would arbitrage whatever price differences between the control areas that exist in the unit commitment process, there would be no margin on inter-control area schedules to support attaching financial consequences to the inter-control area supply offers in the unit commitment step. Moreover, bidders would risk having real-time obligations to deliver in one ISO, while their generation was committed in the other.

In addition, while the dispatch would be optimized over the entire Northeast and could make use of generation in other regions for congestion management, this approach would

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additional generation. Loads could manipulate the market in the opposite direction by submitting bids to buy power from control area 1 for export to control area 2 that were not matched by bids to sell power in control area 2. This particular gaming strategy could be mitigated by eliminating price sensitive inter-control area supply and demand offers in the day-ahead unit commitment process and requiring the submission of balanced bids to buy and sell energy between pools, but market participants could still game the market through schedules designed to distort the unit commitment and create uplift.

[109] It should be noted that these kinds of potential inconsistencies between import schedules and unit commitments implicitly exist today, but they are resolved outside the price calculation process through bilateral commitment of sufficient resources to support day-ahead export schedules. The imposition of a combined dispatch step on top of separate unit commitment processes means that the dispatch and price calculation step would not take account of the output of units that might be bilaterally committed to satisfy these schedules and creates the potential for infeasibilities and/or irrational prices in the day-ahead markets.

not be able to commit resources in one region to solve transmission constraints or to meet load in an adjacent region. This could result in anomalies in the commitment as some ISOs could commit units based on their individual unit commitment solutions, but the operation of these units would appear uneconomic after the determination of prices in the joint dispatch step because of low cost imports. Conversely, some ISOs could fail to commit units in their individual unit commitment process that would be economic based on the prices calculated in the final combined dispatch step. This situation could arise if the inter-control area import and export bids used in the unit commitment step are not consistent with the actual level of exports in the dispatch step. This outcome is inevitable if market participants are permitted to submit price sensitive offers for inter-control area imports and exports. This approach would therefore sacrifice most of the potential gain from coordinated day-ahead commitment, particularly with respect to congestion management.

Iterative Approach

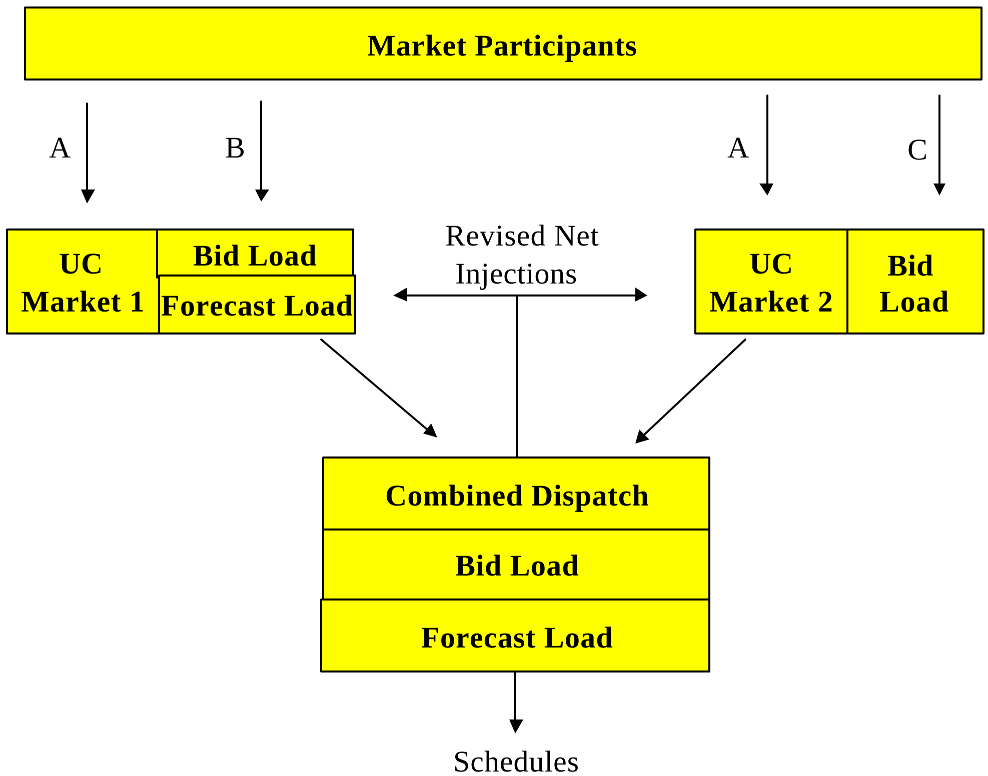
The limitations of the one-pass approach are so extreme that it does not merit further evaluation. The more critical of these limitations could be addressed, however, by adding iterative steps to the approach. This variation on the separate unit commitment and combined dispatch approach is portrayed in Figure 11. The critical features of the iterative approach would be that after the first round solutions to the separate unit commitment problems, there would be a combined dispatch to meet bid load and forecast load based on this unit commitment.[110] This step would include the scheduling of ancillary services, so inter-control area reserve sharing provisions could be implemented at this point in the program. An evaluation would then be made of whether to accept the unit commitment solution or to loop back through the unit commitment process for another iteration. This evaluation could be based on the magnitude of the differences between the locational prices of energy and ancillary services calculated in the individual unit commitment step and the locational prices calculated in the combined bid load

[110] If all of the control areas used a PJM approach to forecast load, this step could be restricted to a bid load dispatch. Control areas using a New York approach to forecast load, on the other hand, would test their ability to meet forecast load in this step.

dispatch step, and on the magnitude of the differences in the total as-bid production cost between these steps. If these differences were sufficiently small, the final prices and schedules would then be calculated based on the bid load and the initial unit commitment.

Figure 11

Iterative Approach



If the differences in prices or production cost were sufficiently large in the first interaction, however, net injections and withdrawals would be calculated based on a combined dispatch and these data, along with the constraint set and reserve schedules for the other control area from the combined dispatch would be passed into the iterative unit commitment process.[111] These net injections and withdrawals for each control area would then be used as the input for another pass through the separate unit commitment

[111] A detail to be evaluated further if this approach were pursued would be whether this dispatch would be based on bid load or forecast load. One of the complexities in this approach would be the development of appropriate schedules in cases in which the forecast load case did not solve. The approach would presumably be to allow the forecast load dispatch to violate the load constraint, and use the resulting interchange schedules in the next iteration.

processes of the two control areas. Thus, the unit commitment process of control area 1 would take the net injections and withdrawals, reserve schedules and constraint set of control area 2 as given, and the unit commitment process of control area 2 would take the net injections, reserve schedules and constraint set of control area 1 as given. This separate unit commitment step could be structured either as in New York with an initial bid load unit commitment followed by a forecast check test or by using the PJM approach in which the forecast load commitment is undertaken later in the day.[112]

Several features of the iterative approach warrant further discussion. First, the iterative approach is analogous in most respects to the MOU real-time redispatch process. The obvious difference is that the iteration would include unit commitment as well as dispatch and cover each of 24 hours, rather than a single period. There would also be some differences arising from the need to take account of both bid load and forecast load in the security analysis. The iteration would avoid the deficiencies of the one-pass approach, as the initial bids submitted by market participants would serve only as a starting point and the iteration process would ensure that the ultimate combined dispatch was feasible and consistent with the unit commitment.

The iterative approach would also be able to commit units to manage congestion and to allocate reserves across regions so as to reduce costs, although the iterative mechanism described above might not always find the joint optimum unit commitment for either congestion management or reserve sharing. The general approach allows for the possibility of passing more or less information between steps so as to improve the quality of the iterative solution. The tradeoff of course is that if too much information is passed, it would be faster to simply solve the joint unit commitment problem directly.

[112] The PJM approach of basing the initial unit commitment, prices and schedules on bid load with a subsequent forecast load test could lead to somewhat anomalous outcomes in such a multi-control area system. For example, if control area 2 committed to meet forecast load using a PJM system, the resources within control area 2 that might provide capacity to meet forecast load could be scheduled to meet bid load in control area 1 in the combined day-ahead unit commitment and bid load scheduling process, requiring control area 2 to secure resources to meet forecast load from control area 1. There would also be a potential for transmission congestion problems to arise in the subsequent forecast load evaluation of control area 2, after control area 1's unit commitment was fixed.

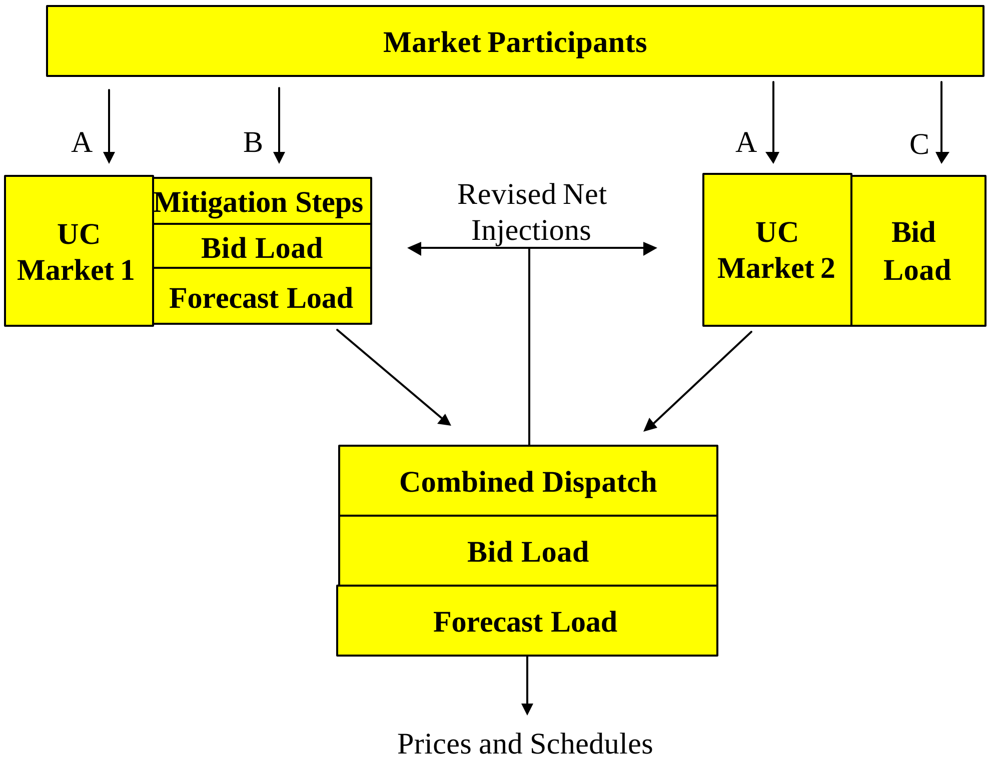
The key limitation of the iterative approach is the potential time required for iteration, and the potential for delayed posting by all of the control areas involved because of difficulties with the unit commitment solution for a single control area. The New York SCUC currently requires 15-30 minutes to iterate from scratch to a secure unit commitment and dispatch solution for a 24 hour day. The ISO-NE unit commitment program is likely to take considerably longer. The time required to solve would likely increase when solving a full network model for the Northeast and analyzing the constraint set for the broader region.[113] Although the model would certainly eventually be able to iterate to a reasonable solution, the starting point provided by market participant external schedules might not be particularly good, and a number of rounds of iteration could be required for reasonable convergence given this starting point, leading to a very long unit commitment process.

A related characteristic of this approach, and one that is in common with most of those that are discussed later in this chapter, is that its workability will require minimizing the number of special steps included in the day-ahead unit commitment process for the purpose of implementing market power mitigation or allocating costs. Market power mitigation mechanisms that operate within the control area unit commitment program, such as the Con-Ed market power mitigation plan in New York, will need to be included in the initial unit commitment step, which may therefore actually include several steps, as elaborated in Figure 12. It is essential to the workability of this approach, however, that these market power mitigation mechanisms be only visited once, and be bypassed in the iterative steps.

[113] Solution time could probably also be enhanced by excluding identifiable intra-control area constraints that would not be affected by changes in external unit commitment from the constraint set passed in the iterative process.

Figure 12

Iterative Approach with Mitigation



Extra steps that are included within the unit commitment program for the purpose of cost allocation, on the other hand, need to be completely eliminated from the day-ahead solution process.[114] Extra steps required for the allocation of uplift costs could still be run on an off-line basis. They would simply need to be removed from the actual commitment run.

<u>Other Common Features</u>

In addition to the issues discussed above, the approach has a number of features that, while not necessarily limitations, need to be kept in mind.

[114] For example, the forecast load step in the NYISO unit commitment program is used only for cost allocation purposes. The actual unit commitment would be unchanged if this step were skipped.

A feature of either the one-pass or iterative approach, in common with all of those that follow in this chapter, is that its implementation would require elimination of transaction-specific charges on imports and exports. There are two reasons for this. First, retention of these charges, such as New York's TSC charge on export transactions, would cause the dispatch step to schedule transactions that would be uneconomic when the transaction charge is taken into account. Second, because inter-control areas schedules would be determined by the dispatch program, there would be no one to pay the transaction specific charge (there would be no transaction, only net interchange), nor would there be anyone who scheduled the transaction to pay a transaction specific fee.

A second significant feature of this approach is that its implementation would require implementation of the MOU process for coordination of the real-time dispatch. This approach determines day-ahead schedules and prices based on a combined day-ahead dispatch. If the individual control areas do not similarly coordinate their dispatch in real time, the solution determined in the combined day-ahead market might not be economic or even feasible in real time.

A third feature of this approach is that it would permit the day-ahead as well as real-time schedules to be based on more exact specification of the inter-control areas transmission constraints that would likely enable more transfer capability to be utilized in the day-ahead market under most circumstances.

A fourth feature of this approach, again in common with most of the approaches that follow, is that congestion rents would be collected for the system as a whole and would not follow control area lines. There will therefore need to be mechanisms for collectively auctioning financial transmission rights, collectively funding payments to transmission rights holders, and allocating auction revenues. In addition, the revenue inadequacy impact of scheduled and unscheduled transmission outages would fall on the single pool of congestion rents, potentially shifting outage costs between control areas as well as between transmission owners. It may therefore be desirable to develop rules that allocate the uplift costs associated with transmission outages to the responsible entity.[115]

A fifth feature of this approach, again like most of those discussed below, is that the tighter integration of the control areas would pose a challenge for separate ICAP programs. Under this approach, New York loads east of Central East would pay for New York ICAP, but that capacity would be interchangeably dispatched to meet load in NEPOOL or New York. The concept of a combined unit commitment and scheduling process for the Northeast is fundamentally inconsistent with reliability distinctions within the Northeast, such as recall rules for ICAP capacity. If a unit is committed in New York instead of NEPOOL to meet NEPOOL load, then the NEPOOL load must have an equal claim on that capacity with New York load. If this would not be the case in real time, then the ISO-NE unit commitment process would need to treat New York capacity differently from NEPOOL capacity.

All of the approaches to developing a combined day-ahead market for the Northeast are to a degree inconsistent with separate ICAP markets and rules, but a fundamental line is crossed with the introduction of a combined dispatch and scheduling step. Under the first two approaches to developing a combined day-ahead market in the Northeast, it would be possible for reliability to be evaluated on a control areas basis and for imports and exports to be evaluated differently from internal generation and load. This would no longer be the case under the third approach. The combined dispatch step for determining schedules means that all generation and load within the region must be treated the same. The only difference among loads and generation would in their willingness to buy or sell at a given price.

Sixth, if the combined unit commitment and dispatch is used to schedule reserves across control area lines, a common reserve pricing mechanism with locational reserve prices would be required. Absent a common reserve pricing mechanism, there could be

[115] Similar issues are raised by the real-time interregional redispatch process with respect to real-time congestion rents.

material anomalies in the compensation paid to a generator scheduled to provide reserves or energy in the day-ahead market. Moreover, with the increased scope of the market, locational pricing for payments to reserve providers[116] and a locational allocation of reserve costs would be required to avoid material costs shifting and pricing anomalies.

A seventh feature of this approach, again in common with all of those that follow, is that implementation would be improved if a common methodology for taking account of losses in the dispatch were employed across control areas. NYISO and ISO-NE currently dispatch generation to minimize the cost of meeting load, including losses, using generator-specific dispatch factors which reflect the cost of losses. PJM has historically not taken differences in the cost of incremental losses into account in its real-time dispatch or day-ahead schedules, but has indicated that intends to implement such a system in the future. While generation could be scheduled taking account of the losses associated with generators located in New York and NEPOOL and ignoring the losses associated with generators located in PJM, this would result in many anomalies that would likely be unacceptable to market participants. Since PJM intends to move to a dispatch and pricing system based on marginal losses, this should not be an issue.

Finally, while not absolutely required, this approach, like the other approaches with a combined pricing and scheduling approach that follow, would perform better if all of the control areas included in the market had a common set of rules regarding the submission of virtual load and generation bids at internal locations in the day-ahead market. Since virtual load bids at external locations would not provide a very good proxy for internal loads within such an expanded market, it would be desirable that this common set of rules include an allowance for virtual load bids at all locations, internal and external to the combined market.

[116] For example, if the payment required to the marginal supplier of reserves on Long Island could set the price of reserves throughout the Northeast, there could be major discrepancies between reserve bids, schedules and prices everywhere except on Long Island.

c) Benefits and Costs

Most of the advantages of this approach are common to all of the approaches that determine day-ahead prices and schedules in a combined inter-regional dispatch process. There would be a single set of energy prices and transmission charges, higher levels of inter-control area transfer capability would be available for scheduling in the day-ahead market, interregional reserve sharing could be more effectively implemented, and the likelihood of reliability surprises arising from non-delivery of scheduled imports should be reduced.

Relative to the other approaches including such a combined dispatch for the determination of day-ahead schedules and prices, the central advantages of the iterative approach would be the ability to continue using the individual ISO unit commitment software and the relatively minor changes that would be required in the individual ISO unit commitment software.[117] Moreover, while it would be necessary to develop a dispatch model to determine prices and energy and ancillary service schedules for the combined market, this would only be a dispatch model. No combined regional unit commitment model for the Northeast would need to be developed in order to implement the combined day-ahead market.

A second advantage of this approach is that it would readily accommodate the existing differences in the design of the New York, NEPOOL and PJM day-ahead markets. While the retention of the separate unit commitment processes within the iterative approach might somewhat mitigate cost shifting between control areas, the iterative approach would be conducive to cost shifting. While there would not be a full combined unit commitment process, the combination of the combined dispatch step and the iterative commitment would mean that generation would at times be committed in one control area to solve a transmission or reserve-related reliability problem in another control

[117] The network model would need to be expanded to include the other control areas within the combined day-ahead market and at least some transmission constraints in the other control areas would need to be modeled.

area.[118] The avoidance of inter-control area cost shifting, particularly with respect to uplift costs, would likely require after-the-fact reruns of the various unit commitment programs for cost allocation purposes, or the acceptance of potential for interregional cost shifting.[119]

Aside from cost shifting associated with uplift costs, a more tightly integrated market would change prices and revenues. In general, generation prices would not rise as high within a combined market, because of more alternatives from which loads would buy on the generation side, but would also not fall as low, because of more alternatives to which generators could sell.

The critical uncertainties regarding the performance of this approach are the number of iterations required to reach a consistent solution, the overall impact on execution time for the day-ahead unit commitment and scheduling process, and whether the approach would rapidly converge to a reasonably good solution. These issues are amenable to empirical evaluation but would require development of combined network models for the unit commitment programs of the affected ISOs in order for this testing to proceed.

4. Separate Unit Commitment with Data Exchange and Combined Scheduling

a) Overview

A fourth approach to coordinating a combined day-ahead market for the Northeast that has been considered is an approach under which the individual unit commitment and scheduling software would be partially solved in parallel by the individual control areas in the Northeast. Information would then be exchanged between the control areas, and final solutions determined for each of the day-ahead individual unit commitment and scheduling processes. This approach to the development of a combined day-ahead market would attempt to achieve the benefits of the iterative approach described above,

[118] It is doubtful whether the iterative approach would ever need to create uplift in another control area as a result of a local reliability rule.

but also would attempt to avoid the potential need for a series of time consuming iterations within the day-ahead market process. This would be accomplished by replacing reliance on market participant inter-control area transactions schedules as the starting point for the unit commitment with the exchange of information with the unit commitment processes of the other control areas within the combined Northeast day-ahead market.

The conclusion of this review, however, is that this kind of approach has limitations that suggest that it would function less favorably than would several of the potential alternatives and should not be pursued, at least in the variations discussed below.

b) Discussion

There are a number of points in the individual control area unit commitment and dispatch programs at which information could be exchanged, but exchanging data late in the unit commitment solution process offers little benefit relative to the iterative approach. One choice would be to exchange bid curves calculated in the initial unconstrained dispatch step of the various individual control area unit commitment programs. This step is usually relatively fast and occurs at the front end of the unit commitment process. Each ISO could exchange with the other ISOs the bids of resources not committed in the initial unconstrained dispatch step and the bids of capacity not dispatched in this step. Each ISO would then combine these external bids with its own internal bid data for the remainder of the individual control area unit commitment process. The final dispatch step in which day-ahead prices and schedules would be determined, however, would be a combined dispatch for the entire Northeast region.

This approach represents a fundamental break with the preceding approaches in that market participants have no direct role in determining inter-control area schedules. A critical problem with this approach is that it could end up with two or even three ISOs

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[119] Cost shifting is particularly likely to arise with respect to units committed of provide ancillary services for a particular control area or to meet forecast load.

implicitly committing the same unit to meet their own load. For example, it would be likely that if NEPOOL and New York both had higher prices than PJM, both ISOs might commit the same low cost unit in PJM (that was not committed by PJM itself in the unconstrained dispatch) to meet load within NEPOOL and New York. In a worst case, PJM itself might have committed this same unit in a later constrained stage of its own SCUC so that the unit would be committed in all three solutions. In the final dispatch step, in a manner similar to that under Approach 3, it would emerge that the individual unit process led to under-commitment for the northeast as a whole, and the aggregate commitments were inconsistent with the dispatch. The result of such under-commitment could be extremely high prices in the final dispatch step and prices that would be materially inconsistent with the actual unit commitment.

A second limitation of this approach is that it would not be likely to improve on the iterative approach unless the information exchange follows the implementation of any market power mitigation provisions. In the context of the New York unit commitment program, this means that the information exchange would come after SCUC has already completely solved the unit commitment program once, and begun with the unconstrained unit commitment using the mitigated bids. This means that the data exchange would come 20-40 minutes into the program rather than 5-10 minutes into the program, which reduces the attractiveness of the approach. Exchanging data at an earlier point would be meaningless because the data would be likely to be materially inconsistent with the final unit commitment.

Aside from these disadvantages, this approach would have many of the same features as the preceding iterative approach. First, its implementation would require elimination of transaction-specific charges on imports and exports. Second, its implementation would require implementation of the MOU process for coordination of the real-time dispatch. Third, it would permit the day-ahead as well as real-time schedules to be based on more exact specification of the inter-control areas transmission constraints which would likely enable more transfer capability to be utilized in the day-ahead market under most circumstances. Fourth, congestion rents would be collected for the system as a whole rather than along control area lines. There will therefore need to be mechanisms for collectively auctioning financial transmission rights, collectively funding payments to transmission rights holders, and allocating auction revenues. Fifth, the tighter integration of the control areas would pose a challenge for separate ICAP programs. Sixth, if the combined unit commitment and dispatch is used to schedule reserves across control area lines, a common reserve pricing mechanism with locational reserve prices would be required. Seventh, a common mechanism for accounting for the cost of losses in the dispatch would be desirable. Eighth, a common set of rules regarding virtual demand and supply bids at internal locations and allowing virtual demand bids would be desirable.

5. Hierarchical Unit Commitment with Combined Scheduling

a) Overview

A fifth approach to the development of a combined day-ahead market for the Northeast that has been identified in the course of the feasibility study is the possibility of developing a hierarchical day-ahead unit commitment and scheduling process based on a combination of separate and combined unit commitment processes to allow the Northeast ISOs to approximate the results obtained through scheduling based on a single day-ahead unit commitment and dispatch process. Like a single day-ahead unit commitment and dispatch process, a hierarchical day-ahead process could allow inter-ISO coordination of congestion management, improve the efficiency of inter-ISO unit commitment schedules, improve the efficiency of inter-ISO schedules for ancillary services, and facilitate one-stop day-ahead settlements for the Northeast. The primary potential advantage of a hierarchically structured software model is that it might solve much more quickly than would the software used to implement a single-site combined unit commitment and dispatch process. It would also likely require fewer software changes for implementation, might reduce cost shifting, and might better accommodate differences in market models than would a combined market coordinated through a single software program.

b) Discussion

Commitment Process

A hierarchical unit commitment and dispatch process could be implemented using the structure as described below and illustrated in Figure 13.

- Step 1: Bids would be accepted for the combined region. Bids would be submitted only once during the day-ahead unit commitment and dispatch process. No interchange schedules would be submitted for transactions within the scope of the combined market. Import and export schedules would be submitted only for transactions with control areas not within the combined market.

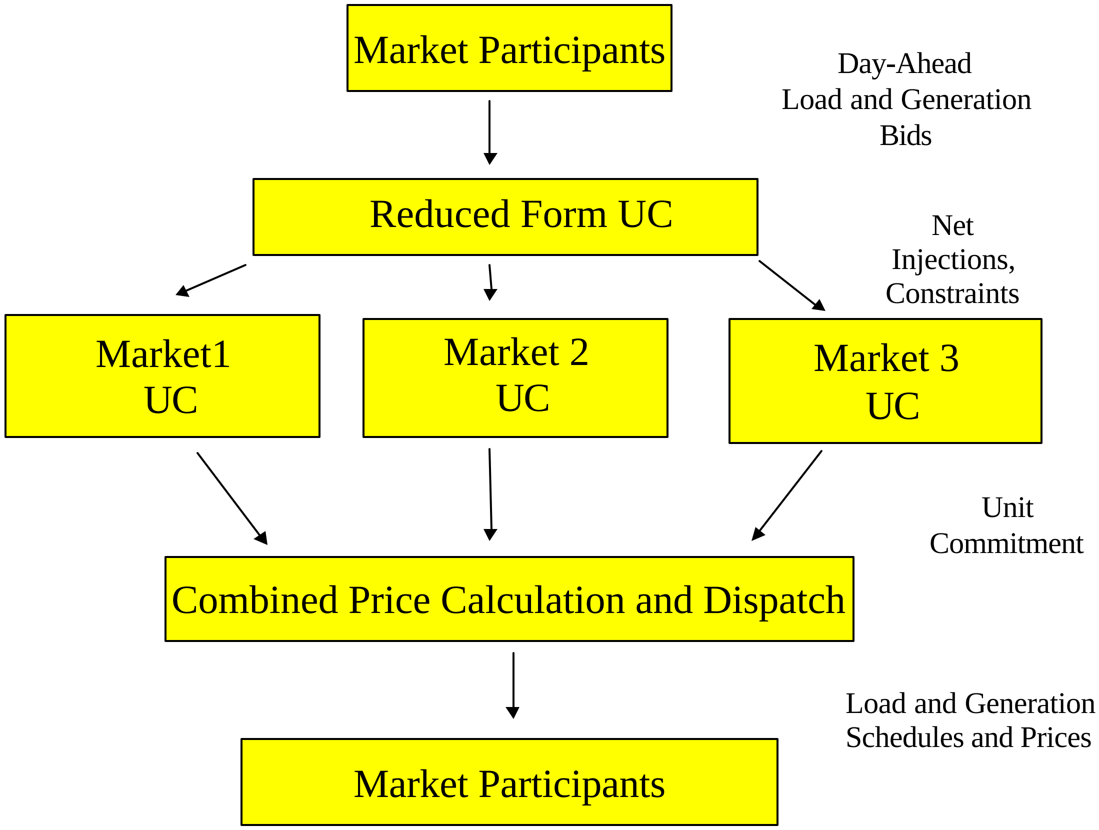
- Step 2: An initial unit commitment would be performed for the combined region by a single program that would commit generation to meet load based on a network model for the combined region, but enforcing a reduced set of constraints and contingencies. The constraint set would at least include the major transmission constraints such as Central East, Boston, Maine-New Hampshire and reserve constraints, including at least some of the locational requirements. The use of a constraint set consisting of only the most important constraints would be intended to significantly reduce the solution time for the combined unit commitment step. The purpose of this step would be to develop a reasonably good approximation of efficient inter-control area schedules. These inter-control areas schedules would be the primary output of the combined SCUC step. The iteration within Step 3 would be enhanced by exporting to that step the final unit commitment and constraint set for each control area from Step 2 (to provide a starting point).

- Step 3: Each of the ISOs would run a separate unit commitment, using the full constraint set for its region, including all local reliability rules, and taking as given the net injections and withdrawals, transmission constraints, and reserve schedules determined for the other control areas in Step 2.[120] This commitment would also be based on a full network model for the combined market, but the commitment would monitor only those extra-control area constraints identified as binding in Step 2. Thus, the second stage unit commitment for control area 2 would take as given the net injections and withdrawals, transmission constraints and reserve schedules determined for control area 1 in Step 2. This step would likely start with the solution to the combined commitment in Step 2, but would not be required to keep units within the individual control area on line.[121] This would simply be a good starting point so as to reduce solution time. Step 3 would iterate to a secure commitment for each control area.

- Step 4: The unit commitment from Step 3 would be fixed and input into a combined dispatch model for the Northeast that would include a complete network model for the combined region and model all transmission constraints and contingencies. The combined region would then be dispatched at least cost to meet bid-in load, while honoring all transmission constraints and reserve requirements. Significantly, the implicit inter-control area flows in this dispatch could differ from those determined in Step 2. This dispatch would determine day-ahead schedules for all generators and loads and LBMP prices at each location.

[120] The intent would be that the network model would be based on the full transmission grid, with net injections and withdrawals outside the individual control area fixed based on the solution to the reduced form model.
[121] The commitment status as well as dispatch of units in the other control areas would be fixed at the step 2 solution.

Figure 13
Hierarchical Approach



Reduced Form Unit Commitment

The effectiveness of this approach depends on the speed and accuracy of the reduced form unit commitment process that would precede the solution of the individual unit commitment programs. These qualities of the reduced form unit commitment process turn on several issues.

The first issue is the treatment of the various special steps that may exist in the unit commitment programs of the various ISOs, in particular the NYISO. This issue pertains at least to market power mitigation rules, forecast load rules and local reliability rules. With each of these rules there is a difficult trade off between adding steps that lengthen the reduced form unit commitment step and ignoring factors that may have an important effect on the individual control area unit commitment solutions.

On the one hand, for example, the initial reduced form unit commitment would not provide a sound basis for calculating the net interchange used in the subsequent individual control area unit commitment processes unless it is based on the same bids that would be utilized in those subsequent stages. This would tend to mandate that any market power mitigation carried out in the course of the day-ahead unit commitment and dispatch processes of the individual control areas would need to be implemented in the first stage reduced form dispatch if this approach is to yield unit commitments that are reasonably consistent with the prices and schedules in the final dispatch step.[122] On the other hand, if multiple unit commitment steps must be performed in order to trigger market power mitigation in the reduced form unit commitment step, the reduced form unit commitment step would be lengthened, perhaps materially. Worse, if the triggering of important market power mitigation provisions requires a full analysis of all transmission constraints, the hierarchical process would be rendered unworkable.

These concerns appear at present to apply only to the NYISO Con-Ed market power mitigation mechanism, which requires an extra SCUC solution step at the front end of the program as discussed in Chapter II in order to trigger mitigation. Bid mitigation under the Con-Ed market power mechanism can have a material impact on the New York unit commitment and therefore needs to be triggered before proceeding with the reduced form unit commitment step. This could entail solving the reduced form unit commitment twice, once with unmitigated bids and then, again with mitigated bids if required. This would nearly double the length of the reduced form unit commitment process when the mitigation is triggered. Moreover, because the Con-Ed market power mitigation is triggered on a location-by-location basis and can be triggered by a variety of constraints,

[122] If the reduced form step is based on much different bids for a material amount of generation than the bids used in the final dispatch step, the implicit net interchange schedules derived from the reduced form step and used to guide the individual unit commitment processes could be materially inconsistent with the interchange schedules that arise from the final dispatch. This would generally not affect reliability, but could give rise to considerable uplift costs due to the commitment of generation to support exports that are uneconomic when evaluated against the prices determined in the final price calculation step.

including relatively local constraints within New York City, all of the constraints potentially affecting the major New York City mitigated generators would need to be included in the reduced form unit commitment step.

An additional prospective burden on the reduced form unit commitment would be the additional market power mitigation programs currently under discussion by the NYISO, the NYPSC and various NYISO market participants within the rubric of a "circuit breaker,"[123] and similar discussions in NEPOOL. Most of the circuit breaker proposals for the NYISO market would entail the addition of one or more unit commitment steps following the current Step IB, i.e. following the unit commitment based on mitigated bids for the Con-Ed divestiture units. These proposals, as well as any similar mechanism developed by NEPOOL, would burden the reduced form unit commitment step. All of these market power mitigation programs would work better if included in the reduced form step in which generation resources in the other control areas could be scheduled to meet load, within the limits dictated by transmission constraints.

Another set of special steps in the individual control area unit commitment process arise from the various methods for taking account of any gap between the quantity of load bid in to the ISO's day-ahead unit commitment and scheduling process and the ISO's day-ahead load forecast. The NYISO, NEPOOL and PJM mechanisms share a common philosophical approach of committing sufficient generation to ensure that the ISO is able to reliably meet forecast load, but not insulating load serving entities that do not schedule the loads they serve in the day-ahead market processes from the financial consequences of potentially high real-time prices. Nevertheless, the implementation mechanism is at least somewhat different in each of these control areas.

Both the New York and NEPOOL mechanisms include a forecast load unit commitment step preceding the bid load price calculation step, while the PJM mechanism includes a forecast load unit commitment step following the bid load price calculation step.   These differences could probably be retained within the hierarchical SCUC approach but would

[123] NYISO Circuit Breaker, Concept of Operations, Fifth Draft January 16, 2001.

affect the duration of the overall processes. If the New York and NEPOOL forecast load commitment step were to continue to precede the final price calculation step, then these steps would also need to be included in the reduced form unit commitment, increasing the duration and complexity of that step. Similarly, if the PJM forecast load commitment step were to continue to follow the final price calculation step, then the PJM forecast load commitment would not be included in the reduced form step or in the later individual control area unit commitment step but would instead follow the completion of the hierarchical unit commitment process. The hierarchical approach could therefore be implemented in conjunction with any of the forecast load unit commitment mechanisms, including a combination of different mechanisms, but the implementation would likely be simplified by increased uniformity.

The next set of issues relating to the reduced form unit commitment step relates to the constraints taken into account in reduce form step. The degree to which the hierarchical unit commitment and dispatch approach would produce results that differ from a fully combined unit commitment and dispatch process depends in part on the specification of the reduced constraint set that is analyzed in the reduced form commitment step. Enlarging the set of constraints taken into account would tend to increase the solution time for the reduced form step, as well as to improve the optimization. Thus, the hierarchical approach would probably not yield good results if the capacity and costs of capacity committed by the individual control areas unit commitment processes were materially different than the commitment in the first stage as a result of the transmission constraints and local reliability rules not modeled in the reduced form dispatch. There is little point to a hierarchical approach, on the other hand, if the reduced form step must include virtually all of the constraints modeled in the individual control area unit commitment processes. Thus, the relative merits of the hierarchical unit commitment and scheduling process and a single unit commitment and scheduling process depends in part on whether a large or small number of constraints need to be taken into account in order to determine the general level of prices in the various control areas.

Similarly, the degree to which a hierarchical unit commitment and dispatch approach would produce a more efficient unit commitment and dispatch than would the sequential approach depends on whether the reduced form constraint set is sufficiently good to enable the hierarchical approach to base the unit commitment on a better approximation of the optimal inter-control areas schedules than is possible using market participant supply offers.

Third, it is envisioned that the hierarchical model would include in the constraint set for each control area any transmission constraints located within the adjacent control areas that were binding in the initial reduced form dispatch. This would ensure that the separate iterations in the unit commitment process do not lead to a commitment that violates constraints governing the unit commitment in the initial step. This approach would also tend to provide much improved inter-control area congestion management relative to the standpoint unit commitment approaches (Approaches 1 and 2). On the other hand, the more such interregional constraints that need to be taken into account in the individual control area unit commitment solutions, the less advantage the hierarchical approach offers over a single combined unit commitment approach.

Fourth, depending in part on the constraints modeled in the reduced form stage of the initial unit commitment, there may be a potential for inter-control area shifting of uplift costs associated with control area or local reliability rules that would need to be accounted for. In general, one would not expect local reliability rules to lead to the commitment of uneconomic units in other control areas that require uplift payments, but this would require evaluation on a detailed basis.

These issues cannot be resolved in the abstract but will require empirical evaluation and testing.

Combined Dispatch Step

Many of the other features of the hierarchical model are common, at least to a degree, to all of the unit commitment approaches that include a combined dispatch step for the purpose of calculating prices and schedules for a combined Northeast market. First, its implementation would require elimination of transaction-specific charges on imports and exports. Second, it would require implementation of the MOU process for coordination of the real-time dispatch. Third, it would permit the day-ahead as well as real-time schedules to be based on more exact specification of the inter-control areas transmission constraints that would likely enable more transfer capability to be utilized in the day-ahead market under most circumstances. Fourth, congestion rents would be collected for the system as a whole rather than along control area lines. There would therefore need to be mechanisms for collectively auctioning financial transmission rights, collectively funding payments to transmission rights holders, and allocating auction revenues. Fifth, the tighter integration of the control areas would pose a challenge for separate ICAP programs. Sixth, if the combined unit commitment and dispatch is used to schedule reserves across control area lines, a common reserve pricing mechanism with locational reserve prices would be required. Seventh, a common system for dispatching and pricing based on marginal losses would be desirable. Finally, a common set of rules regarding virtual demand and supply bids at internal locations and allowing virtual demand bids would be desirable.

c) Benefits and Costs

This approach should be able to achieve most of the important benefits associated with a combined day-ahead market for the Northeast. In particular, it should greatly improve interchange scheduling and avoid reliability surprises, allow for inter-control area congestion management and reserve sharing, and expand the geographic market in which suppliers compete to sell energy and ancillary services.

The critical cost issues associated with this approach pertain to the complexity and duration of the reduced form unit commitment step. If this step can be kept relatively fast and simple while producing a reasonably good, but not perfect, unit commitment, this approach may be preferable to a single combined unit commitment for the Northeast. If the reduced form unit commitment step begins to resemble the size and length of such a single combined unit commitment solution, then there is no point to this approach.

One other important difference relative to the sixth approach is that the hierarchical approach would be slightly more tolerant of model differences across the control areas and slightly better able to assign responsibility for uplift costs to those responsible.

6. Single Unit Commitment with Combined Scheduling

a) Overview

A sixth alternative to improving day-ahead interchange scheduling and congestion management would be to run a single-site combined day-ahead unit commitment and dispatch process for the Northeast ISOs. Under this approach, the schedules for the region would be jointly optimized, and congestion would be managed regionally. This approach would in effect treat the Northeast as a single control area.

b) Discussion

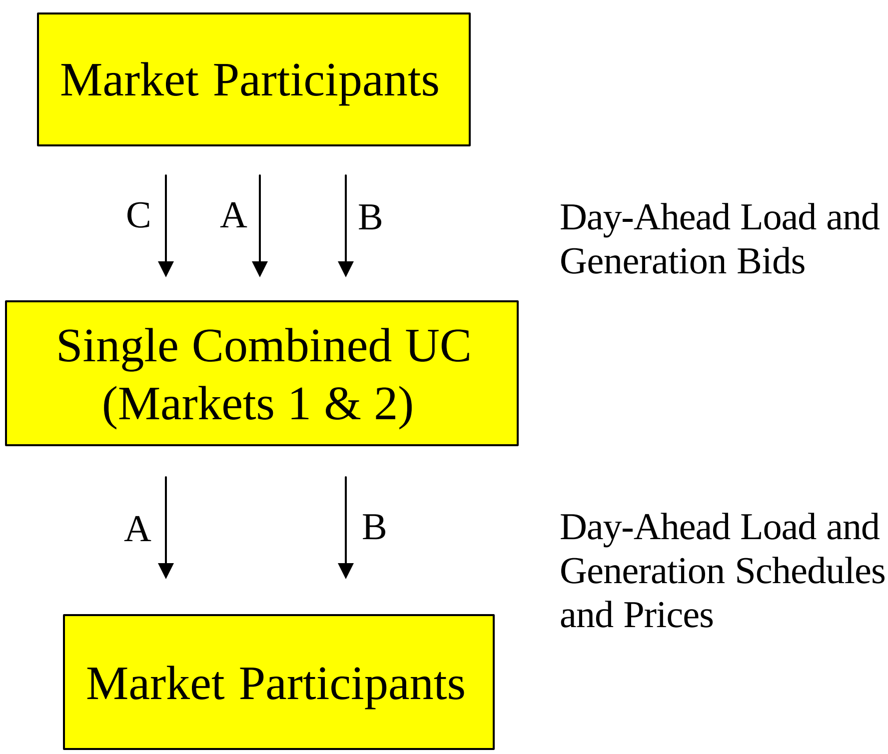
A single simultaneous day-ahead unit commitment process could be implemented as described below and portrayed in Figure 14.

- Step 1: Bids would be accepted for the combined region. Bids would be submitted only once during the day-ahead market process. No interchange schedules would be submitted for transactions within the scope of the combined market. Import and export schedules would only be submitted for transactions with control areas not within the combined market.

- Step 2: Unit commitment would be performed for the combined region in a single program solving for the full network model, the full set of constraints and contingencies, and any local reliability constraints.

- Step 3: The unit commitment from Step 2 would be fixed and input into a combined dispatch model for the Northeast that would include the full network model, all transmission constraints, transmission and generation contingencies, and reserve requirements. The combined region would then be dispatched at least cost to meet bid-in load, while honoring all transmission constraints, and reserve requirements. This dispatch would determine day-ahead schedules for all generators and loads and LBMP prices at each location.

Figure 14
Single Commitment Approach



It is possible that within the overall single day-ahead unit commitment and dispatch process, some decentralized information processing (validating bids, transforming bids as required for processing, and mapping load bids by node) may be done at the individual ISO level.

Time and Scope

The central issue with this approach is the required solution time associated with the large number of constraints to be analyzed in a single unit commitment process for the Northeast region. Under this approach, it would be desirable to avoid repetitive solutions of the unit commitment problem, as the increased number of constraints to be taken into account would likely increase the solution time for each step proportionately to the increase in constraints. As discussed in Chapter II, the NYISO SCUC structure currently solves the unit commitment problem four times in the course of a single SCUC run. Moreover, circuit breaker mechanisms are under discussion that would entail solving the unit commitment problem a fifth or sixth time. The single combined unit commitment model would entail increases in the scope of the network model, in the number of units to be evaluated, as well as in the number of constraints.

The current NYISO unit commitment model includes one step (Step II) that is needed only for cost allocation purposes.[124] While a combined unit commitment process for the Northeast would require mechanisms for tracking and allocating uplift costs, it would be essential under the combined unit commitment approach that these mechanisms not be built into the unit commitment process itself, but that they be undertaken off-line in an accounting time frame.[125] The allocation of uplift costs associated with local reliability rules to the appropriate transmission customers would then require another accounting step, but it would not need to be included within the time frame of the day-ahead unit commitment process.

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[124] It is likely that similar cost allocation issues will arise with respect to the uplift costs associated with locational reserve requirements in NEPOOL following implementation of the NEPOOL CMS/MSS.

While the single combined unit commitment approach could accommodate either or both of the New York/NEPOOL or PJM approaches to committing capacity to meet forecast load, retaining both approaches would stretch the duration of the overall process. Thus, if the single combined unit commitment program included a forecast load step prior to the calculation of prices in the combined dispatch step, and the entire program were then rerun after the combined dispatch step to commit additional generation in PJM, the length of the overall day-ahead unit commitment process would obviously be increased.

Finally, simple market power mitigation systems that do not require the calculation of market prices to determine their effect would greatly facilitate this approach as well as most of the other approaches. Because the single combined unit commitment approach for the Northeast would likely not solve nearly as fast the individual control area problems, solving it two, three or four times may become problematic.

Other Features

The other main features of the combined unit commitment model are common, as discussed above, to all of the unit commitment approaches that include a combined price and calculation scheduling step for the Northeast. First, its implementation would require elimination of transaction-specific charges on imports and exports. Second, its implementation would require implementation of the MOU process for coordination of the real-time dispatch. Third, it would permit the day-ahead as well as real-time schedules to be based on more exact specification of the inter-control areas transmission constraints that would likely enable more transfer capability to be utilized in the day-ahead market under most circumstances. Fourth, congestion rents would be collected for the system as a whole rather than along control area lines. There would therefore need to be mechanisms for collectively auctioning financial transmission rights, collectively funding payments to transmission rights holders, and allocating auction revenues. Fifth,

[125] For example, the results of the NYISO unit commitment could also be achieved if the local reliability rules modeled in Step III were also included in Step IA and IB and Step II were eliminated. See Figure 1in Chapter II. Step III would then be the forecast load step, which would include all transmission constraints.

the tighter integration of the control areas would pose a challenge for separate ICAP programs. Sixth, if the combined unit commitment and dispatch were used to schedule reserves across control area lines, a common reserve pricing mechanism with locational reserve prices would be required. Seventh, a common system for dispatching and pricing based on marginal losses would be desirable. Finally, a common set of rules regarding virtual demand and supply bids at internal locations would be desirable in conjunction with this approach.

c) Benefits and Costs

The combined unit commitment and scheduling process would unquestionably provide the best solution to the need for consistent interchange schedules, inter-control area congestion management and reserve sharing, and expanding the market to mitigate market power. The critical issue is the magnitude of the burden that would be imposed by expanding the scope of the network model, the number of units, and the number of constraints.

7. Single Unit Commitment Process with Separate Scheduling

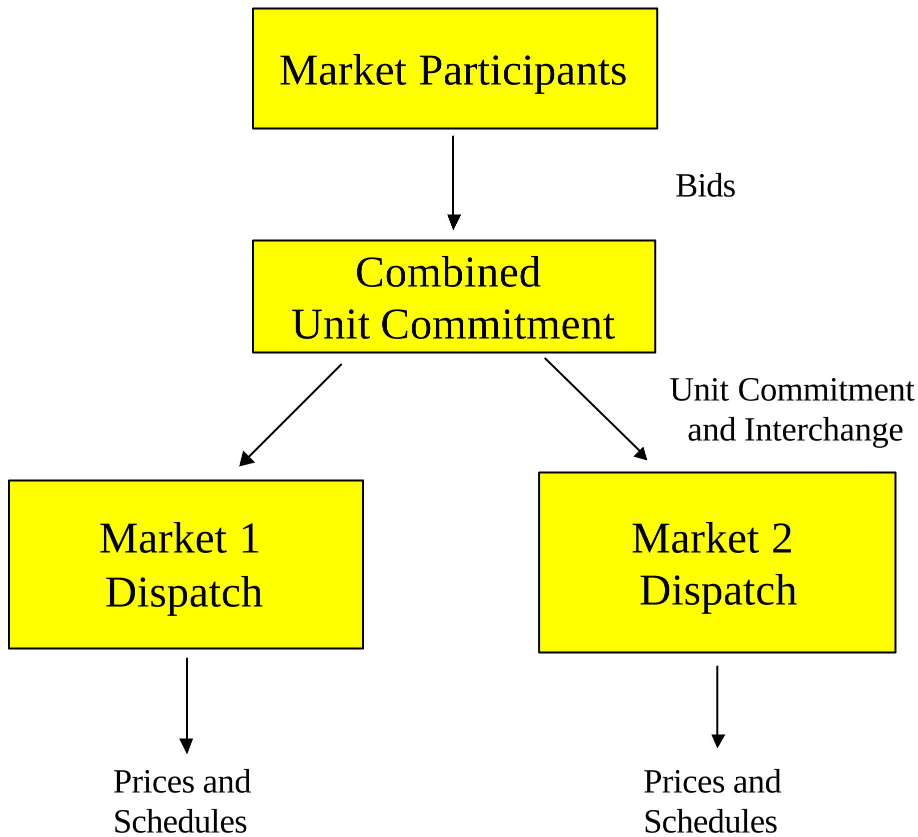
a). Overview

An important feature of Approaches 3 through 6 above is that they include a combined regional dispatch step in which prices and schedules are determined. These approaches are in turn premised upon implementation of the MOU process for real-time interregional redispatch to ensure that the day-ahead schedules determined in this combined dispatch step would be economically sustainable in real time.

This suggests a need to examine whether there could be an alternative approach that would involve a single combined unit commitment process, but would determine the prices and schedules for the individual control areas in separate dispatch steps utilizing the current proxy bus type of representation of the adjacent control areas, as shown in Figure 15. The purpose of this difference would be both to simplify the unit commitment process and to avoid requiring prior implementation of interregional dispatch (to sustain the resulting day-ahead schedules).

Figure 15

Single Unit Commitment, Separate Scheduling



Such an approach confronts some fundamental problems. First, the development of a reliable unit commitment requires the use of an accurate network model for the evaluation of the individual control area unit commitments. The proxy bus approach for external control areas on the other hand entails use of a simplified equivalenced model of the adjacent control areas. A single combined unit commitment would therefore only be acceptable to each of the affected control areas if the network model for that control area is accurate, rather than an equivalenced model. A combined unit commitment process would therefore need to be based on an accurate network model for each of the control areas relying on that model for their unit commitment decisions. Since each control area must base its unit commitment upon an accurate network model, the simplest implementation of a combined unit commitment step using a single model would be to base the single unit commitment model upon an accurate network model for the combined market.

Implementing such an alternative approach would therefore entail running a combined unit commitment step on an accurate network model to determine the level of interchange schedules followed by a separate dispatch step for each control area in which prices and schedules would be determined using an equivalenced proxy bus model for the adjacent control areas, given the interchange schedules. This approach would be workable if the congestion interactions between the control areas were minimal, because the prices and schedules calculated within the individual control area models would then be consistent with the schedules in the combined network model on which the final unit commitment was based. The difficulty with this approach is that if those interactions are not minimal, then a unit commitment whose security analysis is in effect premised on a combined dispatch that recognizes inter-control area interactions may not provide for reliable operation of the network with independent dispatches that do not recognize those interactions.

Thus, the combined unit commitment might find that a constraint in Eastern New York can be managed by dispatching up certain units in PJM. The total production cost of meeting load might therefore be minimized in the combined unit commitment process by relying on PJM units to relieve this constraint, and not committing the New York generation that would be required to manage the constraint absent such a dispatch of the PJM units. The New York price calculation and scheduling step, however, would be based on standard PJM flows which need not, and quite likely would not, include the redispatch required to relieve the Eastern New York constraint.[126] The separate New York price calculation and scheduling dispatch could then find it necessary to accept

[126] The New York scheduling step would need to assume standard PJM flows, because the separate price calculation process on which this approach would be based would mean that the PJM day-ahead schedules and real-time dispatch would not take account of the impact of the PJM generators on the New York constraint.

extreme bids from generators located within New York in order to relieve the constraint in the day-ahead market. Indeed, it might not even be possible to relieve the constraint with the New York reserves committed in the earlier stage.

Whether there would be such material interactions is an empirical question, but it should be recognized that the interregional real-time dispatch process is under development precisely because it is believed that those interactions can at times be material. Moreover, while an effort could be made to empirically assess the potential interactions, there appear to be significant risks of potentially large wealth transfers and potential reliability impacts of adopting an unit commitment model with such important and potentially gamable inconsistencies.

A second possible method of implementing this kind of approach to a combined day-ahead market would require a fundamental change in the nature of the network model. This second approach would use the actual network model and shift factors to model the impact of internal generation on intra-control area constraints for the purpose of unit commitment, price calculation, and scheduling, but would utilize a fictitious set of equivalenced shift factors to measure the impact of generation in one control area on transmission constraints in another control area. The outcomes would be consistent with current practices and would ensure that the security analysis in the day-ahead unit commitment process would be consistent with the redispatch alternatives available in the separate price calculation and scheduling step. The development of such a combined unit commitment and dispatch model would likely require a substantial effort and a substantial period of time.

C. Ontario Issues

The Ontario market model currently differs much more from the New York, PJM and NEPOOL market models than these models differ among themselves. An important issue for the Ontario IMO and market participants is the extent to which the various approaches to a combined day-ahead market can be consistent with the Ontario market model.

First, for the current Ontario market model, the issue is less consistency than relevance. Given the initial lack of a day-ahead market and the limited form of day-ahead market envisioned for later implementation, the development of a combined day-ahead market in the remainder of the Northeast based on the approaches described in Section IV B above would be largely irrelevant for the Ontario IMO and Ontario market participants. Several of the combined market features discussed in Chapter V below would, however, benefit the Ontario market. In particular, a common interface for transaction scheduling and a common set of transmission congestion hedges would benefit the Ontario market and be fully consistent with the present market design.

Second, within the framework of the current Ontario market model, the lack of a day-ahead market for transaction scheduling will likely in effect make the NYISO day-ahead market the de facto day-ahead scheduling mechanism for external transactions between Ontario and New York. The important coordination issue would then be between the NYISO BME and the Ontario hour-ahead scheduling process.

Third, among the approaches discussed, the sequenced approach to a combined market would provide the most benefits to the Ontario market in its current form and would also be the most accommodating of market model differences were the Ontario market to be modified in the future. It is important to recognize that while Approaches 5 and 6 could not be implemented to include Ontario without these existence of a day-ahead market in Ontario (as there would be no day-ahead supply and demand bids to evaluate), these approaches could be implemented absent a locational pricing system in Ontario, by leaving the mechanism for providing generators an incentive to operate as scheduled in the combined Northeast day-ahead market to the internal Ontario market mechanism.

Thus, if the financial obligations arising from purchases and sales in a combined day-ahead market based on either a hierarchical or single unit commitment system were borne by the Ontario IMO, which would settle any deviations between day-ahead schedules and real-time net injections and withdrawals at LMP prices, then the mechanisms the Ontario IMO employs to control its financial exposure would not be a matter of concern to the other Northeast ISOs within the combined day-ahead market. That is, whether the Ontario IMO incented market participants to perform as scheduled using a LMP type pricing system, a non-locational pricing system with constrained on or off-payments, or a command and control mechanism would not matter to the other ISOs.

D. Evaluation of Alternative Structures

The first conclusion drawn from the discussion of alternative approaches in section IV B is that Approaches 4 and 7 are not workable and that the implementability of the iterative version of Approach 3 is questionable. The focus in evaluating options for the Northeast ISOs in implementing a combined day-ahead market should therefore be on choosing between moving to a sequenced but separate day-ahead unit commitment and scheduling process that better enables market participants to effect a combined day-ahead market or moving to a fully combined day-ahead market using either the hierarchical approach (Approach 5) or a single unit commitment process (Approach 6).

A second conclusion is that because the hierarchical and single commitment approaches require full implementation of the interregional real-time redispatch mechanism, their implementation is not a short-term alternative but rather should be viewed as a potential next step that could be implemented once the interregional real-time redispatch has been successfully and fully implemented and is routinely used to manage congestion and redispatch generation in the Northeast. By fully implemented, it is meant that these approaches could be implemented once the MOU real-time redispatch is used on a more or less continuous basis to redispatch energy in the Northeast, not merely that it is available for use in emergencies or as a last resort.[127] In addition, implementation of

[127] A combined day-ahead commitment and dispatch process such as that underlying the hierarchical and single unit commitment rests on the premise that generation will be redispatched across control areas to meet load and manage congestion based on least-cost dispatch principles. If the inter-control area

either the hierarchical or the single unit commitment model would be facilitated by, and may require, a transition to simpler market power mitigation mechanisms than those presently approved by FERC for New York, that do not require a full unit commitment solution and calculation of locational prices to trigger mitigation or bid caps.

Third, it does not appear from the preliminary evaluation that the sequential approach has complex problems requiring long periods of time to solve, nor it does appear to entail large implementation costs or to raise some of the complex cost shifting issues associated with the hierarchical and single unit commitment approaches. The adoption of the sequential approach as an interim step towards development of a combined day-ahead market until the interregional real-time redispatch mechanism is in place should therefore be further evaluated.

Fourth, the hierarchical and single unit commitment approaches are both potentially workable mechanisms for fully implementing a combined day-ahead market for the Northeast, following full implementation of the interregional real-time redispatch mechanism. The relative merits of the two approaches cannot, however, be fully evaluated without empirical investigation. Critical issues for the hierarchical approach are: first, whether a reduced form model can be developed that yields a sufficiently accurate approximation of the final unit commitment within each control area to provide a valid basis for the final unit commitment process of each other control area;[128] and second, can the initial reduced form step solve quickly enough to provide material time savings relative to a single unit commitment approach.

Critical issues for the single unit commitment approach are: first, whether the overall time required to solve the unit commitment and scheduling process can be reduced to an acceptable level as the scope of the unit commitment problem expands from one control area to two, three or four; and second, the single unit commitment approach would work

redispatch were restricted to emergency conditions, the control areas could find that the combined unit commitment was giving rise to extreme locational prices in real time and large uplifts.

much better if the Northeast ISOs were able to move to common market mechanisms for reserve scheduling and pricing and a common unit commitment mechanism for forecast load in excess of bid load. While the development of single unit commitment process can begin before these decisions are made, implementation will likely be improved if preceded by greater standardization of the market model across the region. It is likely that the relative advantages and disadvantages of the various approaches will be apparent within a few years and convergence should not be difficult, given the very similar structures of all of the market models, other than Ontario.

[128] For example, would the reduced form commitment of generation in NEPOOL be sufficiently close to the final NEPOOL commitment, with respect to its impact on New York and Ontario, to permit New York and Ontario to base their final unit commitment on the reduced from NEPOOL commitment.

Chapter V. Assessment of Combining Market Mechanisms

While the development of a day-ahead market structure has the potential to achieve the benefits of a single combined day-ahead market in a financial, pricing and scheduling sense, there are also further potential benefits from combining various market mechanisms and interfaces.

A. Inter-Control Area Transaction Scheduling

One of the current problems in scheduling inter-control area transactions in the Northeast is the need to separately submit a single transaction to each affected ISO/control area. This gives rise to the potential for inadvertent mistakes that cause the transaction to be submitted to one ISO but not to all affected ISOs, or that cause a transaction to be submitted correctly to one ISO but with an incorrect tag or quantity to another ISO. Further, the overall process raises transaction costs by increasing the time and effort required to schedule an inter-control area transaction.

One approach to reducing mistakes and transaction costs for market participants would be for the Northeast ISOs to implement a single point scheduling system for all inter-ISO transactions. This system would allow market participants to input all of the data required for scheduling an inter-control area transaction through a single interface that would be read by each of the affected ISOs.

It is important to recognize in developing such a system that at present there are legitimate arbitrage strategies that would cause market participants to schedule transactions in the day-ahead market of a single control area, with no intent of flowing that transaction in real time, or intending to cover the day-ahead transaction with real-time purchases. Thus, external transactions can be utilized by market participants as virtual supply and demand bids for the purpose of arbitraging anticipated differences between day-ahead and real-time prices, both within and across ISO-coordinated markets.

This ability of market participants to use external transactions in the day-ahead market for the purpose of arbitraging differences between prices in the day-ahead and real-time markets could be preserved by allowing a market participant to indicate in submitting its day-ahead schedule whether the schedule was to be submitted to both markets or only to a designated day-ahead market.

The same common interface could be utilized in the hour-ahead scheduling process, but at this stage it would be mandatory that any transaction submitted to a given control area would also be submitted to the other affected control areas. This would eliminate the potential for the sham transaction scheduling that has plagued the Northeast ISOs and caused the NYISO to implement ECA "A."[129]

It should be recognized that the need for such a common interface for scheduling hour-ahead transactions would be largely obviated by full implementation of the MOU process for real-time interregional redispatch (with full implementation of interregional dispatch, hour-ahead schedules within the region would cease to have any physical significance). The evaluation of the economic benefits of developing such an improved interface for the Northeast therefore needs to include an assessment of the likely timing of real-time interregional redispatch implementation.

B. Standard Generator and Load Bid Box

Following the development of a single interface for scheduling inter-control area transactions, it may also be desirable to move to a single interface for submitting generator and load bids across the Northeast. Like the rules standardization discussed in Section F below, the single interface would allow for the transfer of information required in one control area but not in another, but to the extent possible would use the same interface to submit generation and load bids. There would be three potential advantages of this approach. First, it would potentially reduce market participant training costs,

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[129] BME bids are used under ECA 20001208A to settle external transactions that are scheduled in BME but do not flow in real time. See http://mis.nyiso.com/public/postings/ecac20001208a.pdf.

transaction costs and the costs associated with errors arising from differences in these interfaces.

Second, the transition to a common interface would facilitate subsequent movement to some version of a single day-ahead market program, because bid box standardization would already exist.

Third, once the common interface was established, the cost of future interface improvements would be reduced because there would only be the single interface to update.

The benefits of such standardization would not be obviated by the implementation of the MOU redispatch process and might even facilitate that implementation by easing the inter-control area exchange of redispatch cost information.

C. Combined Transmission Congestion Hedges

As discussed at length Section B of Chapter IV, there is currently a potential for market participants to pay congestion twice for moving power across the same congested external interface. Market participants can acquire congestion cost hedges from each of the ISOs for such transactions (TCCs from the NYISO, FTRs from the PJM OI, and prospectively FTRs from the Ontario IMO and FCRs from ISO-NE), but the market participant may then pay the value of this constraint more than once in the relevant financial right auctions. As suggested by the discussion in Chapter IV B, it is likely desirable even absent other day-ahead market changes to establish a single financial transmission right that hedges the holder for the congestion costs associated with inter-control area transmission constraints.

These inter-control area constraints are by their nature modeled as simple interface constraints in the current proxy-bus models of external control areas. The external constraints could be separately priced, with a single financial transmission right sold to provide a hedge across the constraint. The entity collecting the congestion rents that would fund the payments to the rights holder could vary somewhat depending on the approach taken to structuring the day-ahead market. Under the sequenced market approach, for example, the bulk of the congestion rents funding the financial rights would be collected in the first market in the sequence and the financial rights would be settled at the price determined in this market.

Under the approaches based upon a single combined day-ahead pricing and scheduling step, there would be no inter-control area transactions as such from a scheduling standpoint, and inter-control area transmission constraints would be included in the network model rather than as interface constraints at the proxy bus. Within these models there would be a need for a combined auction of all financial rights, not merely those explicitly between control areas, as there would be no meaningful interregional boundaries. Moreover, the ISO collecting the congestion rents associated with a particular constraint would not necessarily be the ISO within whose control area the constraint lay.

All of the day-ahead market mechanisms discussed in Chapter IV therefore envision periodic auctions of financial transmission rights across these inter-control area constraints with the auction revenues appropriately divided between control areas.

Finally, the nature of the constraints at issue under the sequenced market and simultaneous separate markets approaches and their relatively small number would permit the financial rights across these interfaces to be defined, auctioned and priced as one directional options. That is, the financial rights would entitle the holder to be paid the price of the constraint when it was positive but would not require a payment when the price of the constraint was negative. While financial rights in the Northeast are otherwise defined as obligations, rather than options, the limited number and special characteristics of inter-control area transmission rights would permit the auction of financial rights across these boundaries defined as options.[130] Importantly, these financial rights options would only hedge the holder for the congestion costs associated with the inter-control area constraint. They would not hedge the holder for the congestion costs associated with the redispatching for intra-control area transmission constraints.

The establishment of transmission congestion hedges defined as financial options would be much more complex and perhaps not feasible under the approaches based on a single combined price determination step (Approaches 4-6 in Chapter IV), as the actual transmission constraints would be modeled in the dispatch. This more accurate modeling of the transfer limits would increase the available inter-control area transfer capability but would also greatly complicate application of the simultaneous feasibility test to financial rights defined as options.

D. Pricing of Transactions Over Controllable Lines

The New York/PJM, New York/NEPOOL, and New York/Ontario interfaces consist of a mix of open ties and controllable lines. At present, the controllable lines are controlled by PARS, but additional DC links are on the horizon. Schedules over the existing PAR controlled lines are handled somewhat inconsistently at present. PJM calculates distinct locational prices for schedules over the PAR controlled lines between Eastern PJM and Eastern NY, the Eastern NYPP bus, and for schedules over the other open ties between Western PJM and Western NY, the Western NYPP bus. New York, on the other hand, establishes prices and schedules to and from a single PJM proxy bus. Similar potential inconsistencies exist between NEPOOL and New York and between New York and Ontario.

[130] The complication in auctioning or otherwise awarding options is the complexity of the required simultaneous feasibility test. This test requires that the awarded financial rights be simultaneously feasible for all combinations of the exercise or non-exercise of the options, see Scott M. Harvey, William W. Hogan, and Susan L. Pope, "Transmission Capacity Reservations and Transmission Congestion Contracts," June 6, 1996 (revised March 8, 1997), pp 41-42. Because all options have value, the simultaneous feasibility test for an unrestricted auction market for financial rights defined as options would be very difficult to implement. Much of the complexity in implementing the simultaneous feasibility test would be

One of the possibilities offered by a combined day-ahead market based on a combined dispatch, with combined pricing and schedules would be to include scheduling of some or all of the PARS internal to the combined market in the day-ahead unit commitment and dispatch process. If this was desirable, then the schedules over these controllable lines would be determined by the ISO/RTO in the course of its day-ahead and real-time economic dispatch, and flows over controllable lines would have no more significance under locational pricing than would the flows over any AC line.

If, however, the schedules for transfers over some or all controllable lines were determined by the market participants, then some improvements to the locational pricing mechanism might be appropriate, particularly in the context of a better integrated day-ahead market. In these circumstances, if the outage of the controllable line were not a binding contingency in the dispatch, then transfers over the controllable line would be priced at the LBMP at the point of receipt within the receiving control area.[131] This pricing would reflect the higher value of incremental deliveries over the controllable line. This higher value would arise because increased schedules over the controllable line would increase total deliveries into the receiving control area, while increased flows over any particular line comprising the open tie would not change total inter-control area deliveries. If the outage of the controllable line were a binding contingency, however, than transfers over the controllable line would be priced identically with transfers over AC interconnects, because the level of flows over the controllable line would not affect the feasible level of inter-control area flows.

Adoption of this framework for pricing transactions over controllable lines within the Northeast would eliminate current anomalies and lead to more efficient unit commitment and real-time dispatch. This framework would also provide better incentives for the construction of additional controllable lines.

avoided, however, for options limited to financial rights across control area boundaries for which the transmission limit is currently defined as a simple interface limit.

[131] These pricing principles are explained in greater detail in Appendix I.

E. Financial Bilaterals

Another interface difference among the markets in the Northeast pertains to the mechanisms for scheduling financial bilaterals. Among the operating markets, NEPOOL and PJM have effective mechanisms for market participants to structure bilateral purchases and sales that are purely financial transactions used to hedge price risk. While the NYISO has a system for scheduling physical bilaterals, it is not possible to structure many kinds of financial bilaterals within the New York MIS system. The Ontario IMO also will have a mechanism for structuring financial bilaterals, although these transactions are referred to as physical bilateral data in the Ontario market.

Moreover, while NEPOOL currently has a system for scheduling financial bilaterals that is generally well received, this non-locational settlement system will require substantial modifications to adapt it to NEPOOL's new CMS market mechanism, and in particular to locational pricing.

Another element of developing a combined market in the Northeast might therefore be to move to a common software interface for scheduling financial bilaterals. Within the current environment this step would likely reduce market participant transaction costs and ISO software development costs. More importantly, this step will be essential with the development of a combined market utilizing a combined pricing and scheduling system. Under Approaches 4 through 6 to development of a combined day-ahead market in the Northeast, there would likely be a desire by market participants to be able to schedule financial bilaterals across control area boundaries.

F. Common Market Rules

Another step that could be taken to develop a common day-ahead market among the Northeast ISOs would be to take advantage of the increasingly similar market designs to develop a common overarching market rules framework. It is not envisioned that this effort would, at least initially, necessarily entail changes in the market rules developed for the individual control areas. Instead, the purpose would be to develop a single set of market rules that would use the same terminology and format to describe the elements of the markets that are identical and would include separate provisions describing the individual control area market rules where differences existed.

This step would potentially reduce market participant transaction costs by reducing the time required for employees to become familiar with market rules across the region, and reduce both market participant costs and ISO reliability concerns by reducing the potential for inadvertent mistakes arising from a failure to understand differences in rules and terminology.

This approach would entail choosing a basic market rule framework, probably from one of the existing ISOs, but perhaps a combination of one or more existing rule sets, and then incorporating the rules of all of the ISOs participating in the joint effort within this framework, using a single terminology where appropriate, and including sections applicable only to a single ISO where appropriate.

G. Conclusions

Each of the six steps towards developing combined market mechanisms described above would likely be advantageous for both market participants and the affected ISOs. Moreover, these steps would likely be advantageous independent of further steps toward development of a combined day-ahead market for the Northeast. In addition, each of these steps would contribute to the success of a combined day-ahead market and an effort should be made to implement them in the transition to a combined day-ahead market.

Chapter VI. Combined Market Impacts

The development of a combined day-ahead market in the Northeast would have impacts on the ISOs, on individual market participants, and on the markets themselves.

A. ISO Impacts

The development of a combined day-ahead market would potentially have several kinds of impacts on the affected ISOs. First, it is anticipated that the development of a combined day-ahead market in the Northeast would reduce the potential for reliability surprises arising from mismatches between market participant inter-control area supply and demand offers and the underlying unit commitment in the importing and exporting control areas. While the current market mechanisms are designed to avoid such surprises by attaching financial consequences to the supply and demand offers, there is a potential for a miscalculation, or the cumulative effect of many small gambles, that would present an ISO with a reliability surprise in which a substantial amount of external supply that was counted upon to meet load cannot be made available from the exporting control area in real time.

A second and related consideration is that the greater reliability of inter-control area transactions within such a combined day-ahead market structure could enable ISOs to operate more efficiently by modifying practices that implicitly or explicitly entail carrying additional reserves, and/or regulation to account for the potential unreliability of external supplies.

Third, it is anticipated that the development of a single combined day-ahead market, utilizing a single unit commitment program would, at least in the long-run, reduce the ISO software development costs associated with the day-ahead market mechanisms. These software costs would include the cost of purchasing the software, the ISO resources devoted to managing software development and software testing.

Fourth, many of the mechanisms for developing a combined day-ahead market, particularly those including a Northeast-wide price calculation and scheduling step, entail solving larger network models, with more units, more constraints, and more contingencies. Each of these factors would tend to increase the solution time for the unit commitment process, i.e. the time elapsed from the deadline for a market participant to submit its bid or schedule to the time at which the ISO or RTO posts accepted schedules and prices. It is inevitable that a transition to a combined day-ahead market would, other things equal, increase the elapsed time from the bidding deadline to the posted schedule. Everything else need not be equal, however. Computer speeds are rising over time, improved algorithms may be developed, and extraneous steps may be removed from the day-ahead market process and shifted into a settlement time-frame.

B. Economic Impacts on Market Participants

The development of a combined day-ahead market in the Northeast would have five general kinds of economic impacts on market participants. First, there would likely be some regions in which a combined day-ahead market based on a combined price calculation step would consistently reduce or increase prices. These regions have not been identified in this study, but it is likely that the availability of inter-control area congestion management would fundamentally change the locational supply and demand balance in some regions.

Second, there would likely be many more regions in which a combined day-ahead market, whether including a combined price calculation step or not, would reduce the volatility of prices. In other words, prices in most regions of the combined market would not rise as high as in individual control area markets nor would they fall as low as they would in individual control area markets. This outcome would be particularly likely for Eastern New York and Southern New England. This outcome would be the result simply of improved inter-control area arbitrage, including interregional reserve sharing and congestion management, which would temper the swings in both energy and reserve prices.

Third, an important impact of the combined day-ahead unit commitment would be to broaden the relevant markets, to the extent permitted by transmission constraints, and thus reduce the potential for the exercise of market power. This expansion of the market and increased competition might also reduce the need for the more intrusive mechanisms used for market power mitigation.

Fourth, improved coordination of transactions among the control areas within the Northeast is likely to at least somewhat reduce the demand for capacity by both reducing ISO and market participant uncertainty and improving resource utilization. As noted above, the potential for reliability surprises may currently increase the reserves carried by the individual ISOs relative to the level of reserves that would be required within a combined Northeast market, thus increasing the demand for capacity. Moreover, the need to hold capacity out of one control area market to hedge offers made in another increases the demand for capacity by market participants engaged in such interregional arbitrage. The transactions costs and uncertainties associated with scheduling inter-control area transactions may also at present increase the demand for capacity by traders and LSEs seeking to hedge forward obligations.

Fifth, the development of combined day-ahead markets based on schedules determined in a combined dispatch step would fundamentally change the role of traders as arbitrageurs in the Northeast. While the current market mechanisms in the Northeast place primary reliance on market participants to arbitrage inter-control area price differences, the real-time interregional dispatch mechanisms would displace traders from this role in real time and a combined day-ahead scheduling process would displace traders from this role in day-ahead markets. Traders would still have a major role in Northeast electricity markets, providing longer-term risk management services and arbitraging differences between the Northeast and other regions, but there would no longer be price differences across day-ahead markets in the Northeast to be arbitraged by traders; those price differences would be arbitraged instantly by the software, just as they are today within the control areas.

C. Market Impacts

The development of a combined day-ahead market for the Northeast would also have significant impacts on the markets themselves. One of the topics discussed in Chapter IV is the various market mechanisms that would need to be adjusted in order to implement a combined day-ahead market, particularly one based on market-wide pricing and schedules. ICAP recall provisions and embedded cost charges on import or export transactions are examples of fundamental market features that would not survive the transition to a combined day-ahead market.

As discussed in Chapter IV, it would be fundamentally inconsistent with the premises underlying a combined regional day-ahead unit commitment process if some of those resources could be withdrawn based on ICAP obligations to particular regions within the combined market area. If such recall rights existed, the individual control areas would need to undertake their own individual unit commitment to assure that non-recallable resources would be available to meet control area load.

Similarly, a combined day-ahead market based on prices and schedules determined in a single regional dispatch would not be practical if interregional schedules were subject to additional transmission usage charges unrelated to the cost of losses and congestion. It would not be practical to account for such charges in the dispatch and, absent some restriction to maintain regional price differences, there would be no mechanism to fund such charges.

Beyond this initial impact, it needs to be recognized that the development of a combined day-ahead market would be a powerful force for the convergence of market rules within the region. While it would still be possible to maintain a variety of the unique market features of the various control areas within a combined day-ahead market framework, there would be a new constraint on market changes, namely the impact on the combined day-ahead market. It is anticipated that processes that would burden the day-ahead market, such as additional special unit commitment steps intended to serve a specific purpose in one or another control area would simply not be acceptable once the combined market structure was implemented.

Finally, the more tightly integrated is the Northeast day-ahead market, the more powerful would be the pressures driving the control areas to move towards a common set of market rules. While most of the alternatives discussed in Chapter IV allow for the preservation of unique market rules in a particular control area, the cost and complexity of doing so would increase with integration of the day-ahead markets within the region. Thus, although differences in reserve pricing, losses pricing, unit commitment for forecast load in excess of bid load, and market power mitigation could readily be accommodated within the sequential approach to a combined market, it would be much more difficult to preserve such differences within a single unit commitment process and single pricing system for the Northeast. Tighter integration of day-ahead markets should therefore be expected to lead relatively quickly to a common set of market rules.

Appendix I

I. Overview

There are two principal factors that affect the pricing of power scheduled to flow over controllable lines. The first factor is whether the schedule is determined by the ISO as part of its overall economic dispatch or is determined by another entity (including the operator of another control area) and provided to the ISO. The second factor is whether the outage of the controllable line is one of the binding contingencies in the ISO's security analysis.

If the schedules for the controllable line are determined by the ISO as part of its overall economic dispatch, then the pattern of flows over the controllable line and other lines are not a result of market participant decisions and all schedules would be identically priced. The ISO could in these circumstances collect congestion rents for flows over the controllable lines, as well as flows over the AC interconnects.[132] If, on the other hand, schedules over the controllable line are determined by individual market participants, then it is necessary that the pricing of those schedules provide market participants with efficient incentives. The discussion below focuses on the case in which the schedules on the controllable line are determined by market participants and provided to the ISO.

The other key factor influencing the pricing of scheduled flow over controllable lines is whether the outage of the controllable line is a binding contingency in the ISO's security analysis. In the circumstance in which the outage of the controllable line is the only binding transmission constraint and contingency, then the total level of transfers (and thus production cost of the receiving control area) does not depend on the schedules over the controllable line. Instead, the total level of transfer is determined by the pattern of transmission flows in the contingency in which flows over the controllable line are zero. In this circumstance, there is no need for a price signal to incent efficient pre-contingency schedules over the controllable line as these schedules

[132] Depending on the compensation arrangements relating to the transfer of control of the controllable line to the ISO, this compensation might require calculation of prices as discussed below.

are irrelevant.[133] If the outage of the controllable line is not the binding contingency or is not the only binding constraint or contingency, then the total level of transfers and production costs will depend on the schedules on the controllable line and optimal scheduling of the controllable line will require a distinct price signal. In these circumstances the value of power delivered over the controllable line can range from being equal to the value of power delivered over the AC interconnect to having a value greater than that of power injected by a generator at the delivery point of the controllable line.

II. Pricing

The pricing of energy delivered from or to external control areas can be formulated in terms of the fundamental LMP pricing equation:

$$P_i = (1 + L_i)\, P_{ref} + \Sigma_j\, \Sigma_k\, SP_{jk}\, SF_{jki};$$

where

P_i	=	Locational price at Bus i;
L_i	=	Marginal loss factor at Bus i;
P_{ref}	=	Locational price at the reference bus;
SP_{jk}	=	Shadow price of constraint j in contingency k; and
Sf_{jki}	=	Shift factor for real load at Bus i on constraint j, in contingency k.

The special consideration in applying the LMP pricing equation to deliveries over controllable lines is that deliveries to a bus over a controllable line would be priced as a distinct delivery point, i.e. the controllable line would be modeled distinctly from generation at that bus. Thus, the price of energy would be calculated both for deliveries over a controllable line to a particular bus and from a generator at that bus, and the prices could differ, depending on the binding constraints and contingencies. In general, the price of power delivered over a controllable line would be greater than or equal to the price of power generated at that bus if the outage of the

[133] It still could be the case that the operation of the controllable line increases total transfer capability and thus

controllable line were not a binding contingency. If the outage of the controllable line were the only binding contingency, then price of power delivered over the controllable line would be less than the price of power delivered from a generator at the delivery point. If the outage of the controllable line were one of two or more binding contingencies, then price of power delivered over the controllable line could be less than or greater than the price of power delivered from a generator at the delivery point.

These pricing principles are illustrated in the examples below. In doing so, it is convenient to begin with the situation in which the outage of the controllable line is not a binding contingency and then consider the more complicated case in which the outage of the controllable line is one of the binding contingencies.

contributes to congestion rents.

Scenario 1 illustrates a situation in which increased schedules over the controllable line would reduce the costs of the receiving control area. It is initially assumed that bus 5 is the receiving control area and thus that lines 6-5, 2-5 and 7-5 are inter-control area ties, as illustrated in Figure 1. Bus 3 is the reference bus in the sending control area that is used operationally by the receiving control area for modeling the source of imports. Line 7-5 is the controllable line. Figure 1 portrays the pre-contingency flows and that there are no binding pre-contingency transmission constraints, or losses.

Scenario 1 Figure 1: (No Outages)

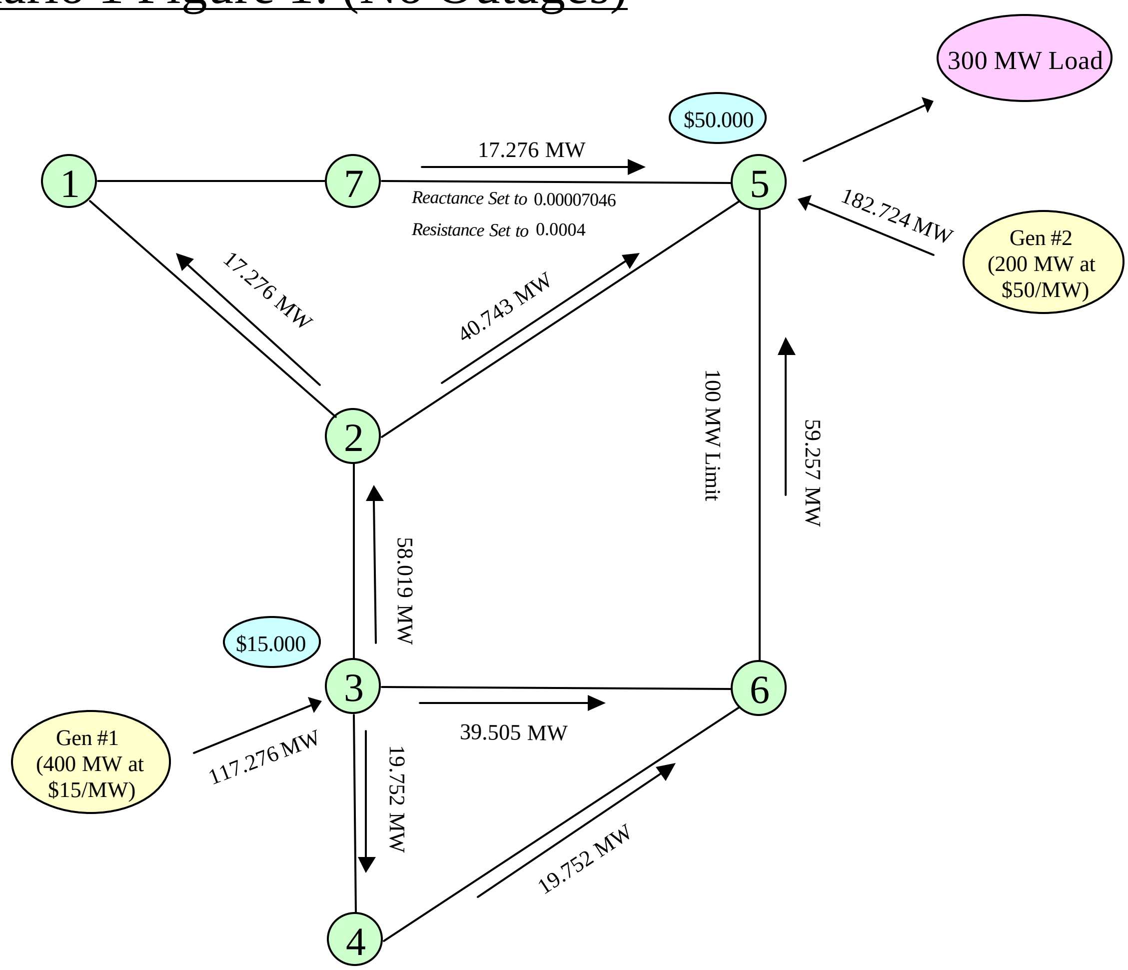


Figure 2 portrays the flows following the outage of the controllable line 7-5. It is seen that the flows on the line 6-5 are well below the 100MW limit and thus that the outage of the controllable line is not a binding contingency and does not limit the level of imports into control area 5 from generation at bus 3.

Scenario 1 Figure 2: (Line 5-7 Outage)

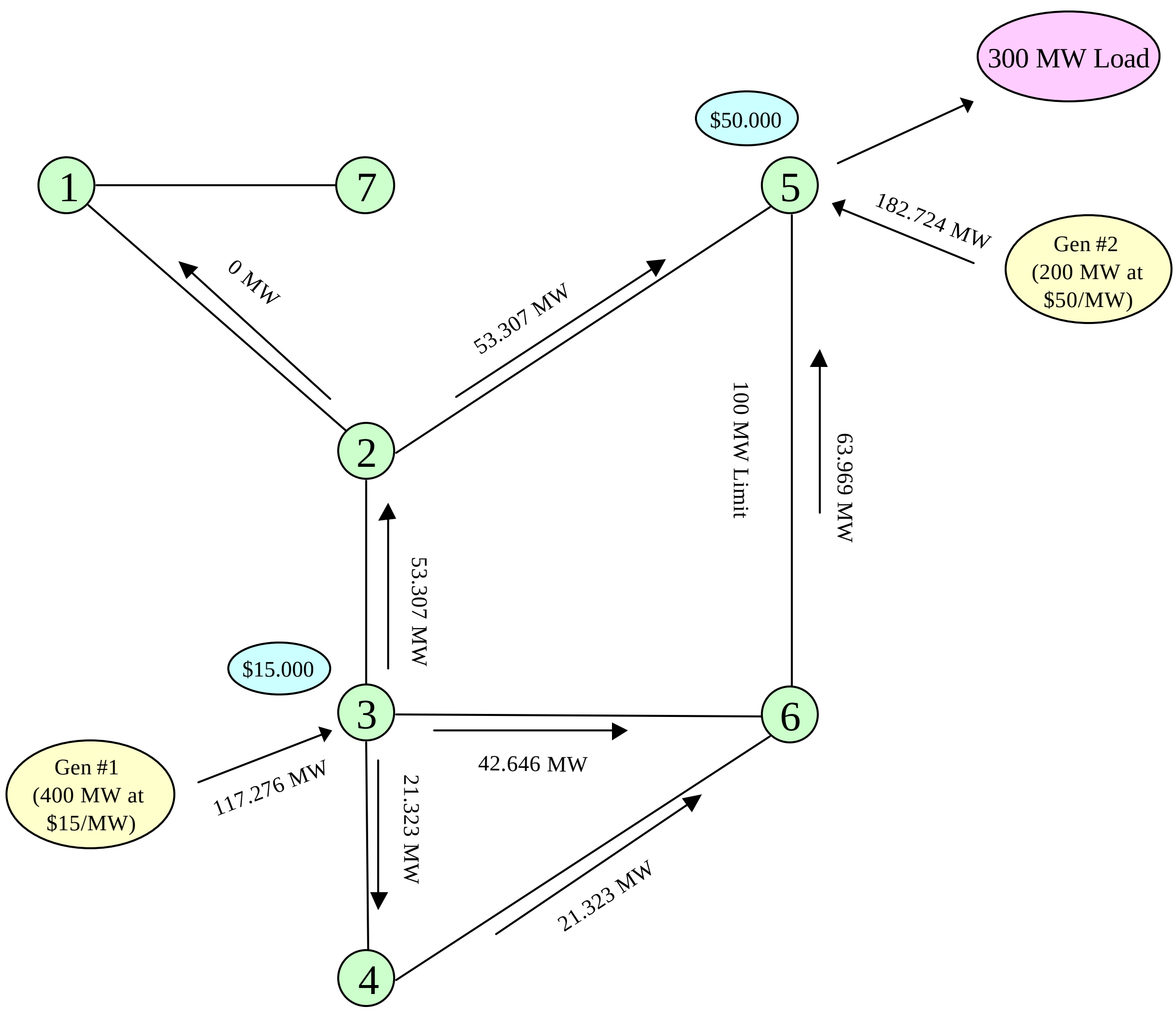


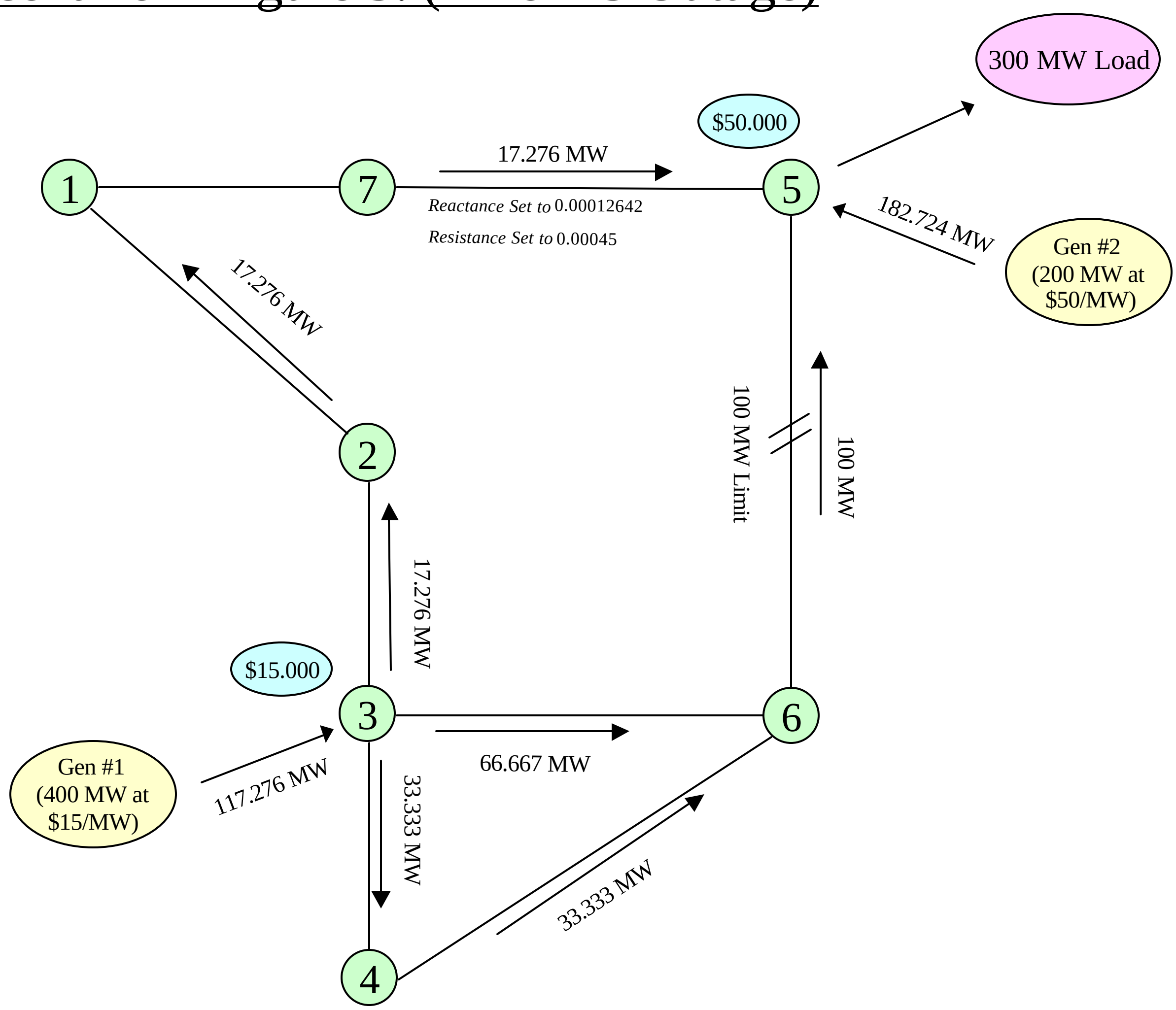
Figure 3 portrays the flows following the outage of the line 2-5. It can be seen that the post-contingency flows over the line 6-5 are at the limit. In this example, we have assumed that the flows on the controllable line are fixed in the contingency and thus that post-contingency flows over the controllable line are unchanged.[134] Because the post-contingency flows over 6-5 are a

[134]This assumption is maintained to simplify the initial discussion of the pricing issues. This assumption is relaxed below in Scenario 2.

binding constraint on injections at bus 3, no additional imports could be scheduled from bus 3, given the settings on the controllable line. In this situation, the price of power at bus 3 is set by the bid of the marginal generator at that location and would be $15 in Scenario 1.

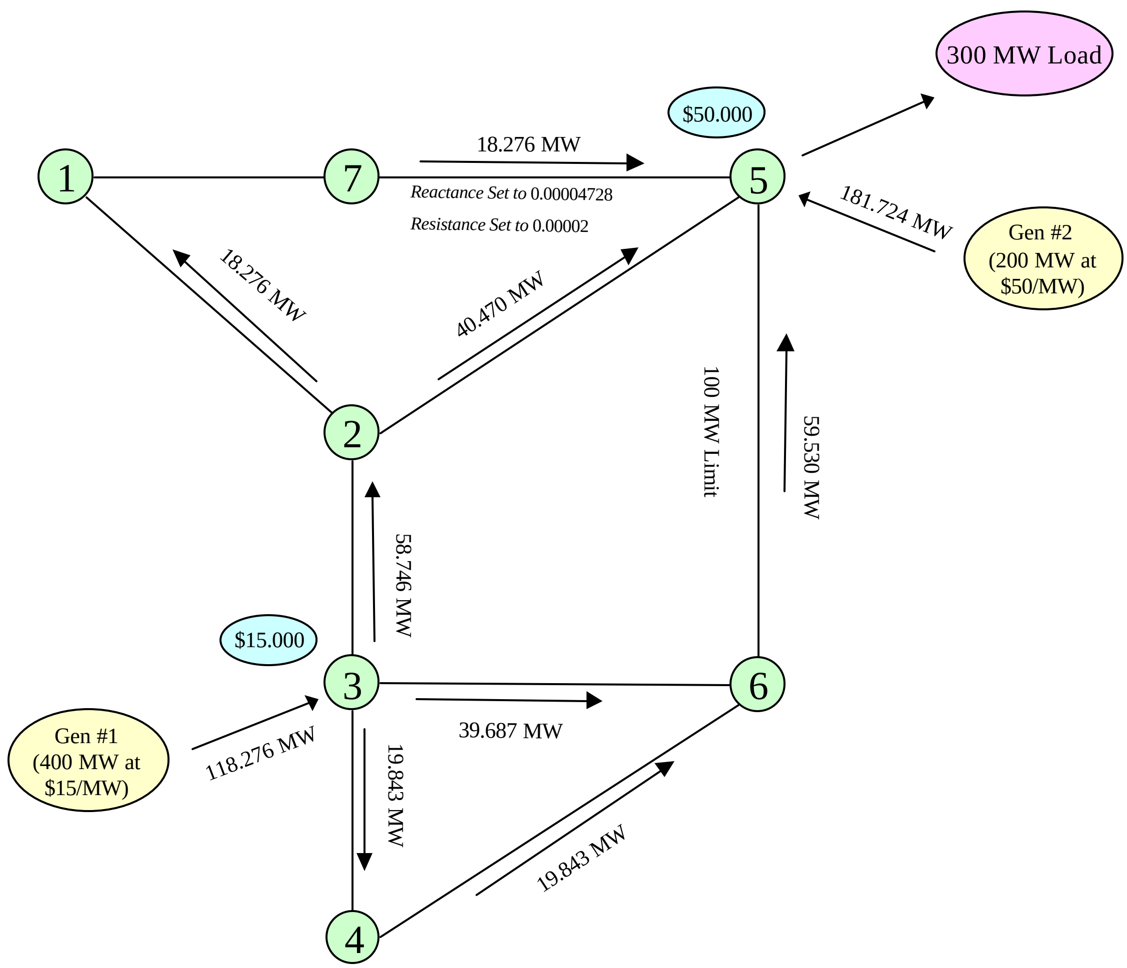
Thus, given the pre-contingency schedules on line 7-5, the ISO for control area 5 would continue accepting generation schedules until the post-contingency constraint on line 6-5 was binding, and the marginal accepted bid at bus 3 would be $15/MW.

Scenario 1 Figure 3: (Line 2-5 Outage)



In the situation described by this scenario, increased schedules over the line 7-5 increase total transfers into the control area at bus 5. The lower the resistance and reactance set on the line 7-5, the higher would be the pre-and post-contingency flows on line 7-5 and thus the higher would be the total transfers into the control area at bus 5.[135] This can be illustrated by considering the impact of a reduction in the resistance and reactance of line 7-5 sufficient to increase pre-contingency flows over this line by 1 MW. These pre-contingency flows are portrayed in Figure 4.

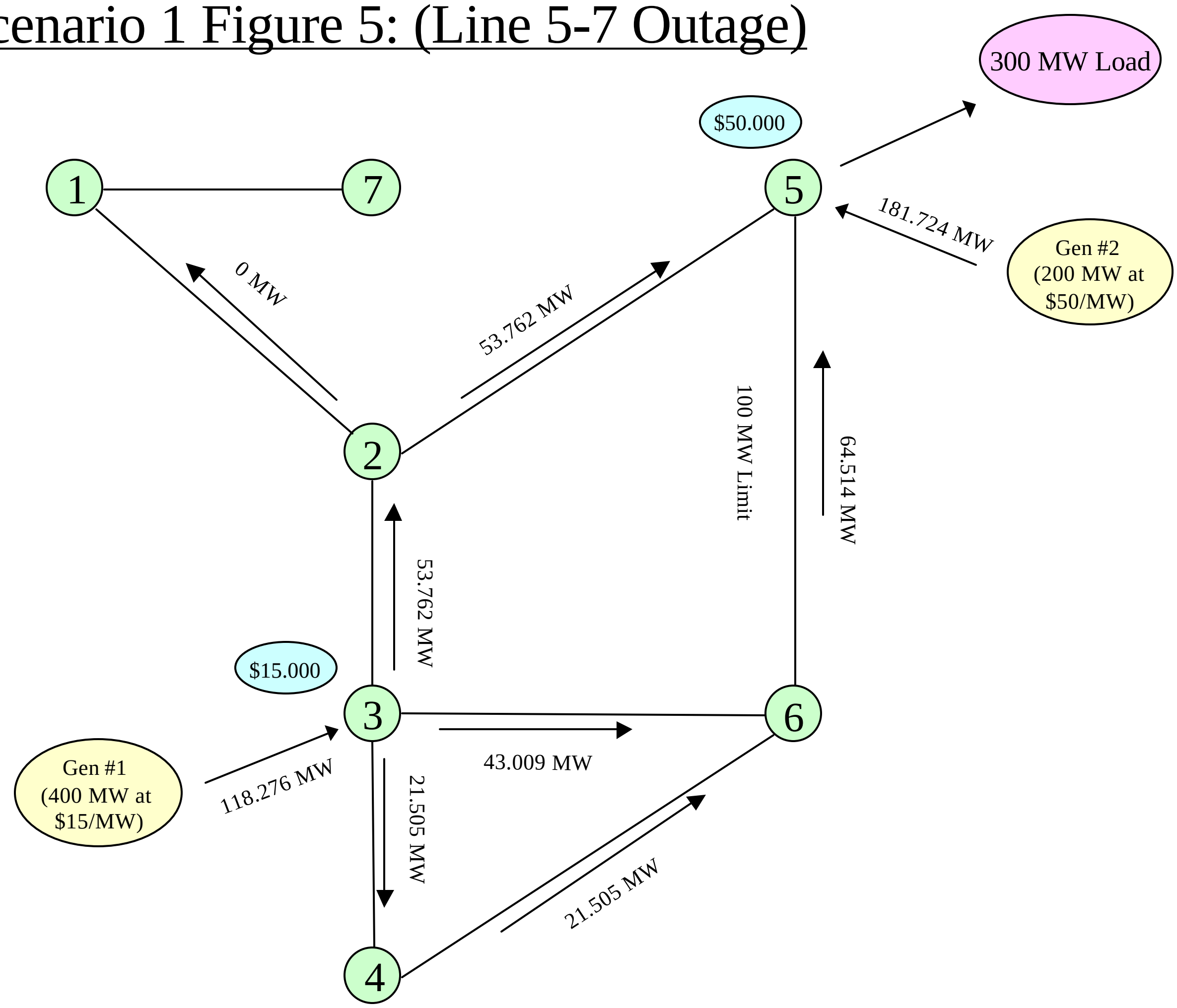
Scenario 1 Figure 4: (No Outages)



135 It can be seen that in this example, the limit on total transfers into the control area at 5 is equal to the post-contingency flows on line 7-5 plus 100MW.

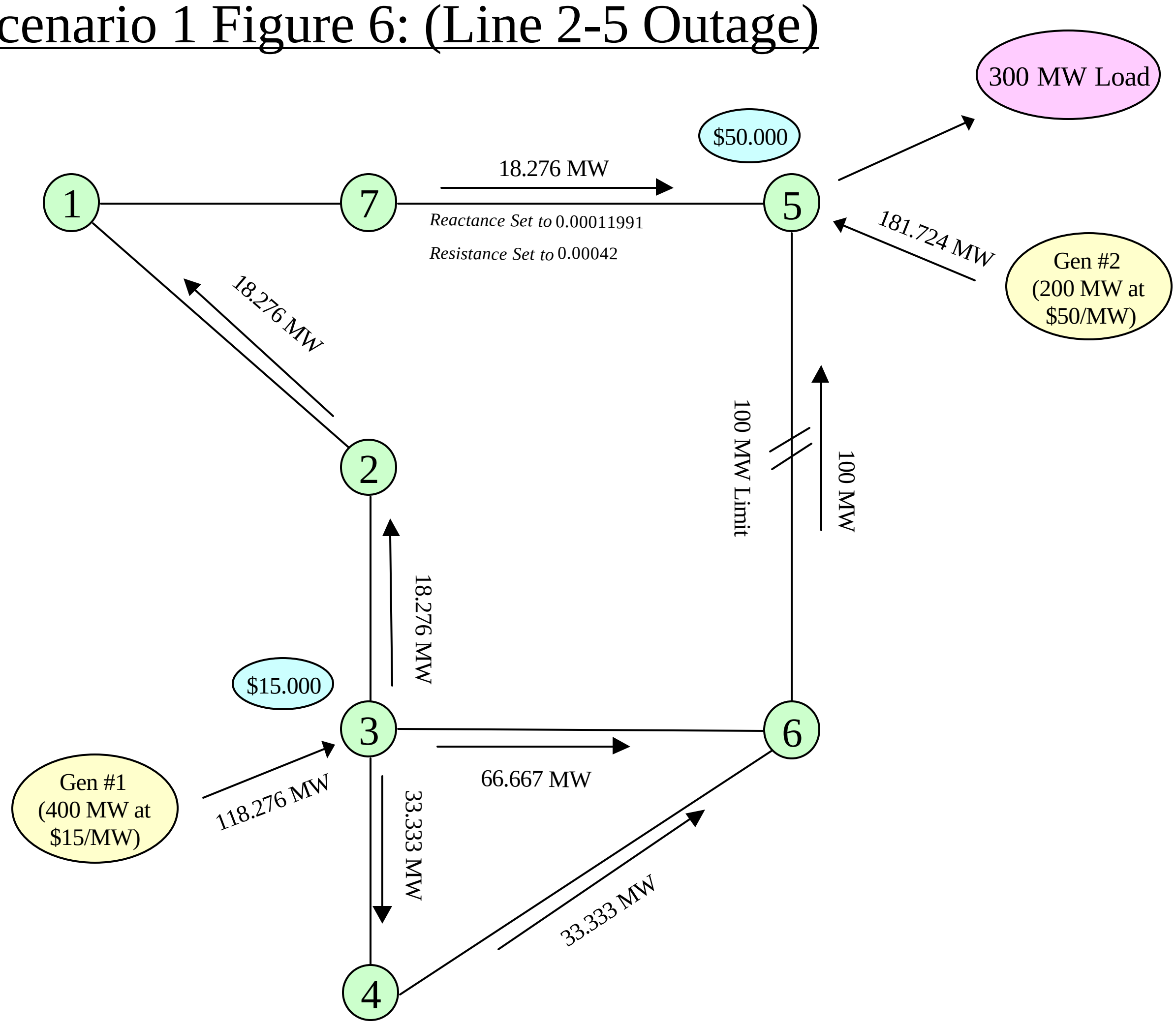
It can be further seen in Figure 5 that it is still the case that the outage of the line 7-5 is not a binding contingency.

Scenario 1 Figure 5: (Line 5-7 Outage)



Finally, Figure 6 portrays the flows following the outage of the line 2-5, which is the binding contingency. As before, it is assumed that flows on the controllable line are held fixed in the contingency.

Scenario 1 Figure 6: (Line 2-5 Outage)



It can be seen by comparing Figures 1 and 4 that a 1MW increase in flows over line 7-5 leads to a 1MW reduction in generation at 5 (from 182.724 to 181.724) and thus to a $50 reduction in the as-bid production cost within control area 5. The value of a MW of power delivered over the controllable line 7-5, is therefore $50/MW. In particular, it is important to note that the scheduling of an additional MW over the controllable line does not reduce scheduled transfers over the AC interconnects (which remains at 100MW), but leads to an increase in the total transfers. Thus, as long as the post-contingency flows on the line 7-5 are at least as large as the pre-contingency flows, an increase in pre-contingency schedules on the controllable line increases total deliveries at bus 5 by 1 MW and thus are appropriately priced at the point of delivery into control area 5.

The schedules over the line 7-5 appear to be a disequilibrium at the prices at bus 3 and 5 in Scenario 1 as incremental schedules on the controllable line would be profitable. The schedules shown would, however, be an equilibrium if there were a pre-contingency limit on flows over the controllable line of 17.276 MW, either to avoid overloading the line 7-5 or to avoid overloading lines 2-1 or 1-7. In this case, prices and schedules would be as shown, but no entity would be able to increase schedules over the controllable line.

Alternatively, the line 7-5 could be a DC line with operating costs. The schedules shown in Scenario 1 would also be an equilibrium if the charge for scheduling power over the controllable line were $35/MWh.

If the controllable line were scheduled by the ISO of control area 5, it would increase schedules on the controllable line until either the price difference between bus 3 and 5 disappeared or one of the constraints became binding. Abstracting from imperfect information, the pricing system would provide market participants with the same incentive, as it would be profitable to increase schedules on the controllable line until one of these constraints became binding.

The discussion above has assumed that bus 5 is a control area and thus that the line 6-5 is an external tie line. The analysis would be essentially unchanged if the control area consisted of buses 6 and 5 and thus the constrained line 6-5 were internal to the control area. Imports flowing over lines 2-5, 3-6 and 4-6 would all be priced at the external proxy bus price, while schedules flowing over the controllable line 7-5 would be paid the bus 5 price.

The discussion above has been simplified by the assumption that the pre- and post-contingency flows over the controllable line are the same. This will generally not be the case, although it could be sustained on DC lines. Figure 7 portrays a slightly different set of pre-contingency flows over the same transmission grid and it is again the case that there are no binding pre-contingency transmission constraints. It is noteworthy that the total injections at bus 3 are higher in Scenario 2 than in Scenario 1, although the pre-contingency flows over the line 7-5 are unchanged. The reason for this is that it is assumed in Scenario 2 that the post-contingency flows over line 7-5 are not fixed, and thus a higher level of injections can be accepted at bus 3 without overloading line 6-5 in the contingency in which line 2-5 is out.

Scenario 2 Figure 7: (No Outages)

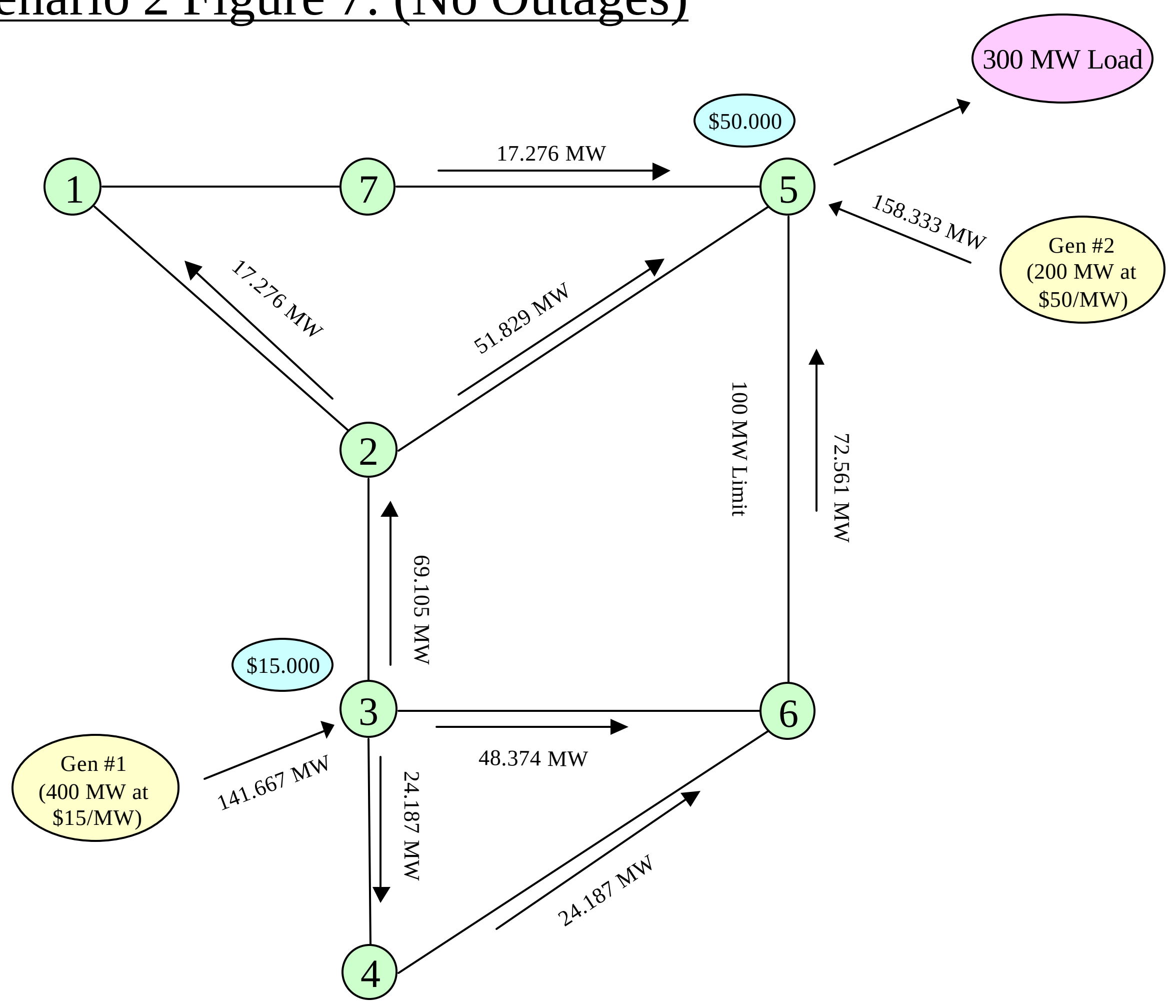


Figure 8 portrays the flows following the outage of the line 2-5. It can be seen that the post-contingency flows over the line 6-5 are at the limit. The example now assumes, however, that the resistance and reactance of the controllable line are fixed in the contingency and thus that post-contingency flows over the controllable line exceed the pre-contingency schedules.

Because the post-contingency flows over 6-5 are a binding constraint, no additional imports could be scheduled from bus 3, given the settings on the controllable line, and the price of power at bus 3 is set by the bid of the marginal generator at that location, which would be $15 in Scenario 2, as in Scenario 1.

Scenario 2 Figure 8: (Line 2-5 Outage)

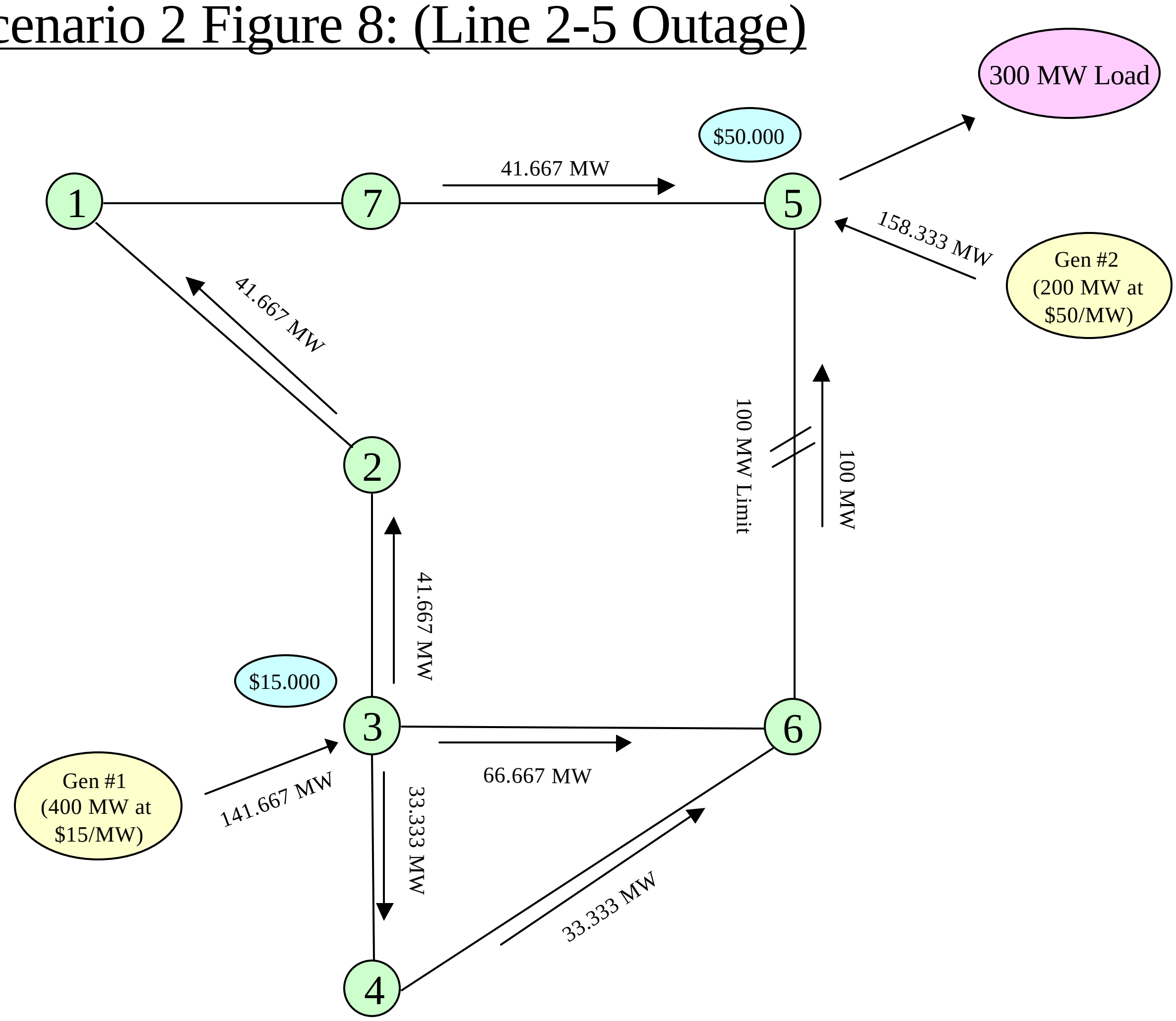
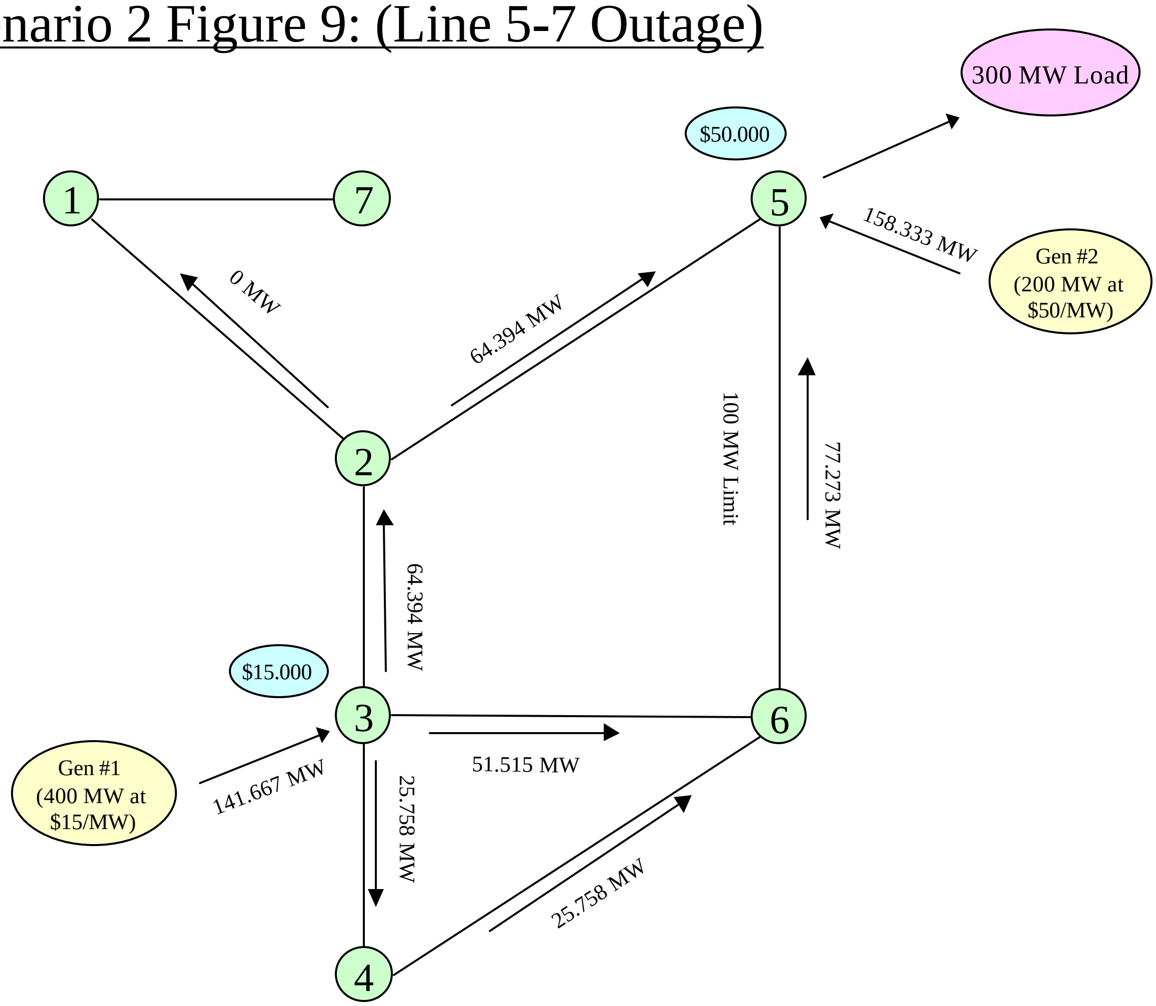


Figure 9 portrays the flows following the outage of the controllable line 7-5. It is once again seen that the flows on the line 6-5 are well below the 100MW limit and thus that the outage of the controllable line is not a binding contingency and does not limit the level of imports from generation at bus 3.

Scenario 2 Figure 9: (Line 5-7 Outage)

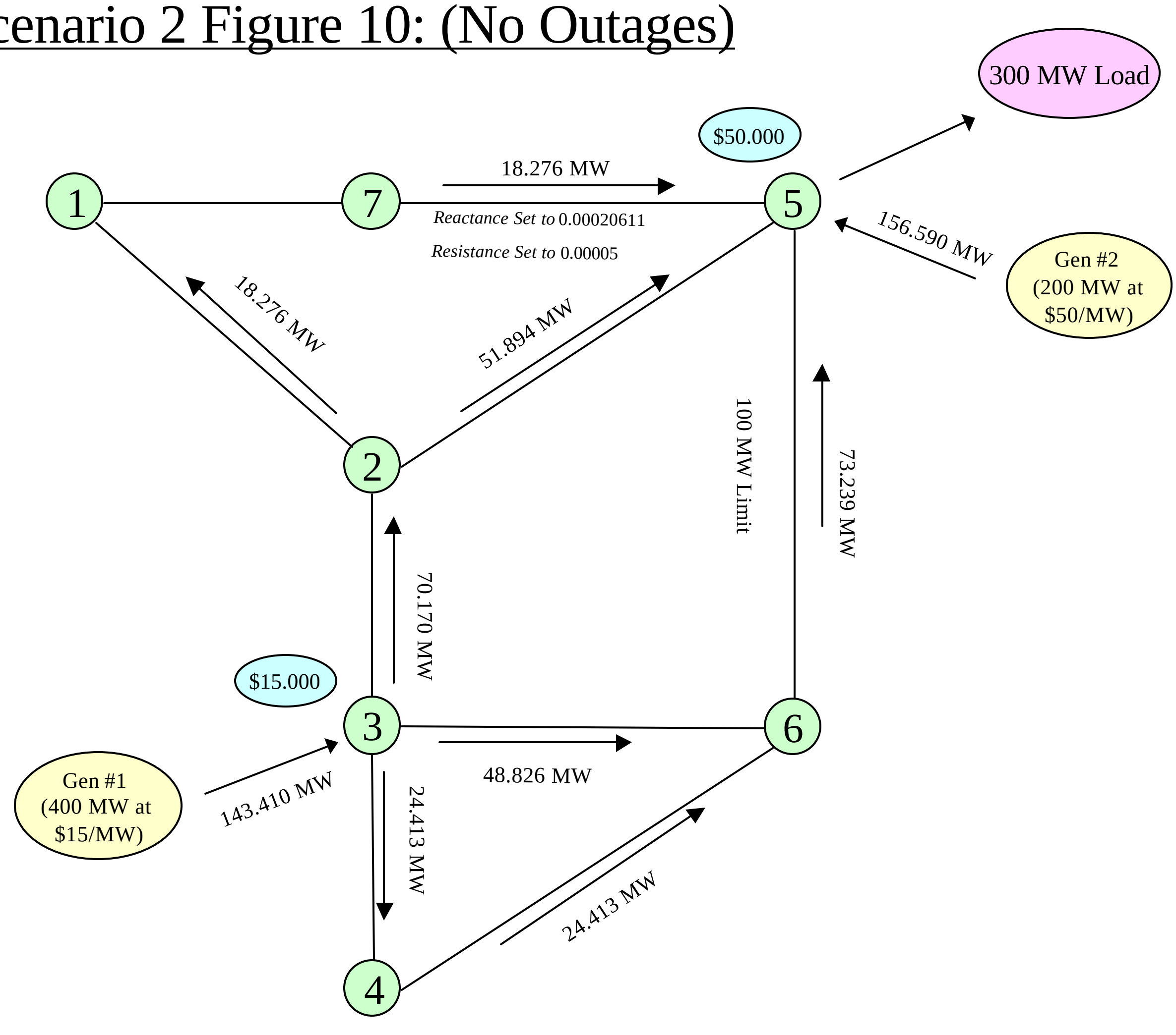


In the situation described by this scenario, increased schedules over the line 7-5 increase total transfers into the control area at bus 5. The lower the resistance and reactance set on the line 7-5, the higher would be the post-contingency flows and thus the higher would be the total transfers into the control area at bus 5.[136] This can be illustrated by considering the impact of a reduction

[136] It can be seen that in this example, the limit on total transfers into the control area at 5 is equal to the post-contingency flows on line 7-5 plus 100MW.

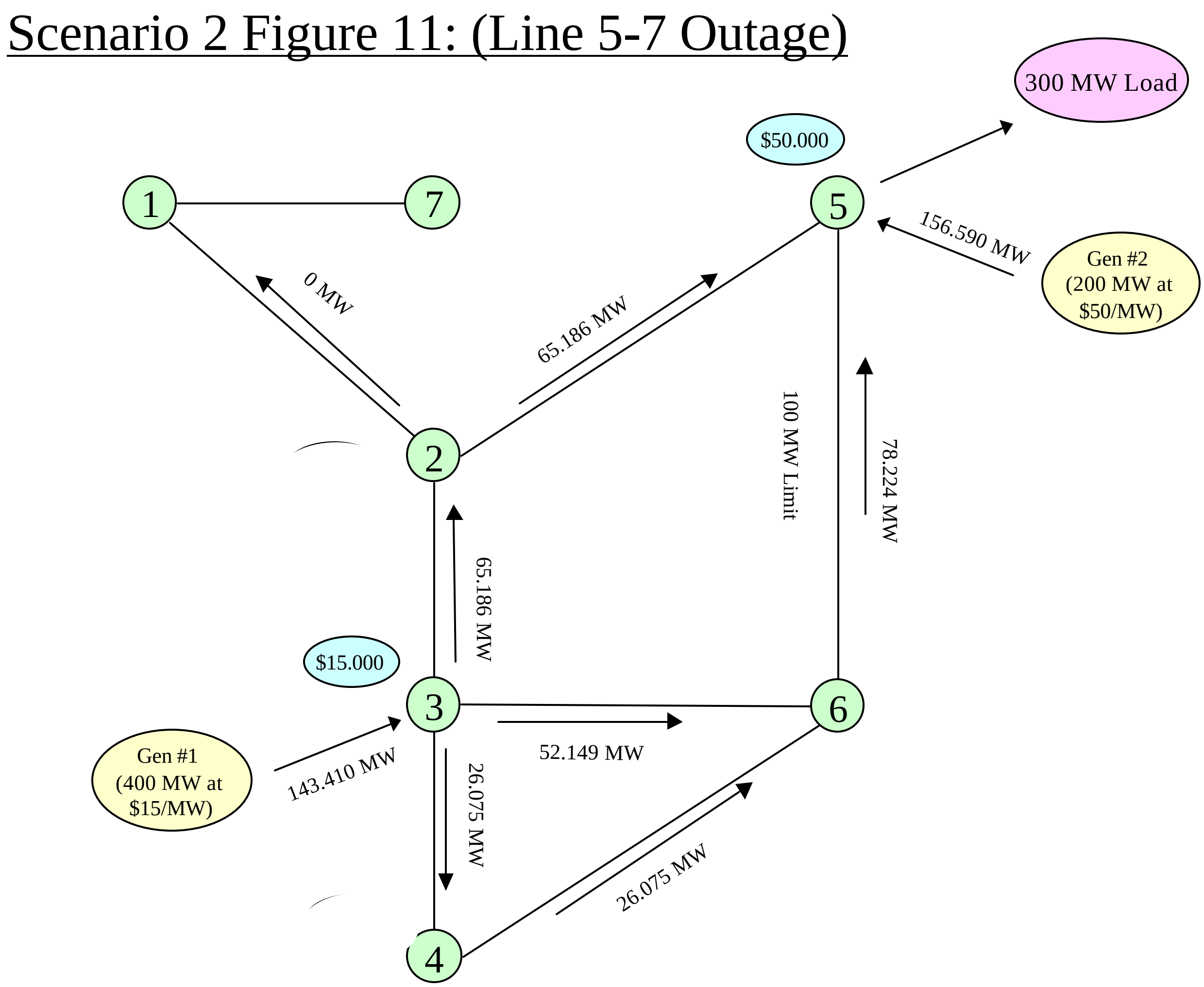
in the resistance and reactance of line 7-5 sufficient to increase pre-contingency flows over this line by 1 MW. This situation is portrayed in Figure 10. It can be seen that a 1 MW increase in pre-contingency flows over the line 7-5, allows total injections at bus 3 to be increased by 1.743MW, thus reducing generation in control area 5 by more than the change in pre-contingency flows over line 7-5. Thus, the changes in total production costs of control area 5 resulting from a 1MW increase in schedules over the line 7-5 is $76.005.[137] This change in production costs results from a reduction of 1.743 MW in the amount of energy injected at bus 5 at a price of $50/MW and an increase in 0.743 MW in the flows into the control area on the open ties at a price of $15. The 1MW required to balance load is delivered over the controllable line.

Scenario 2 Figure 10: (No Outages)



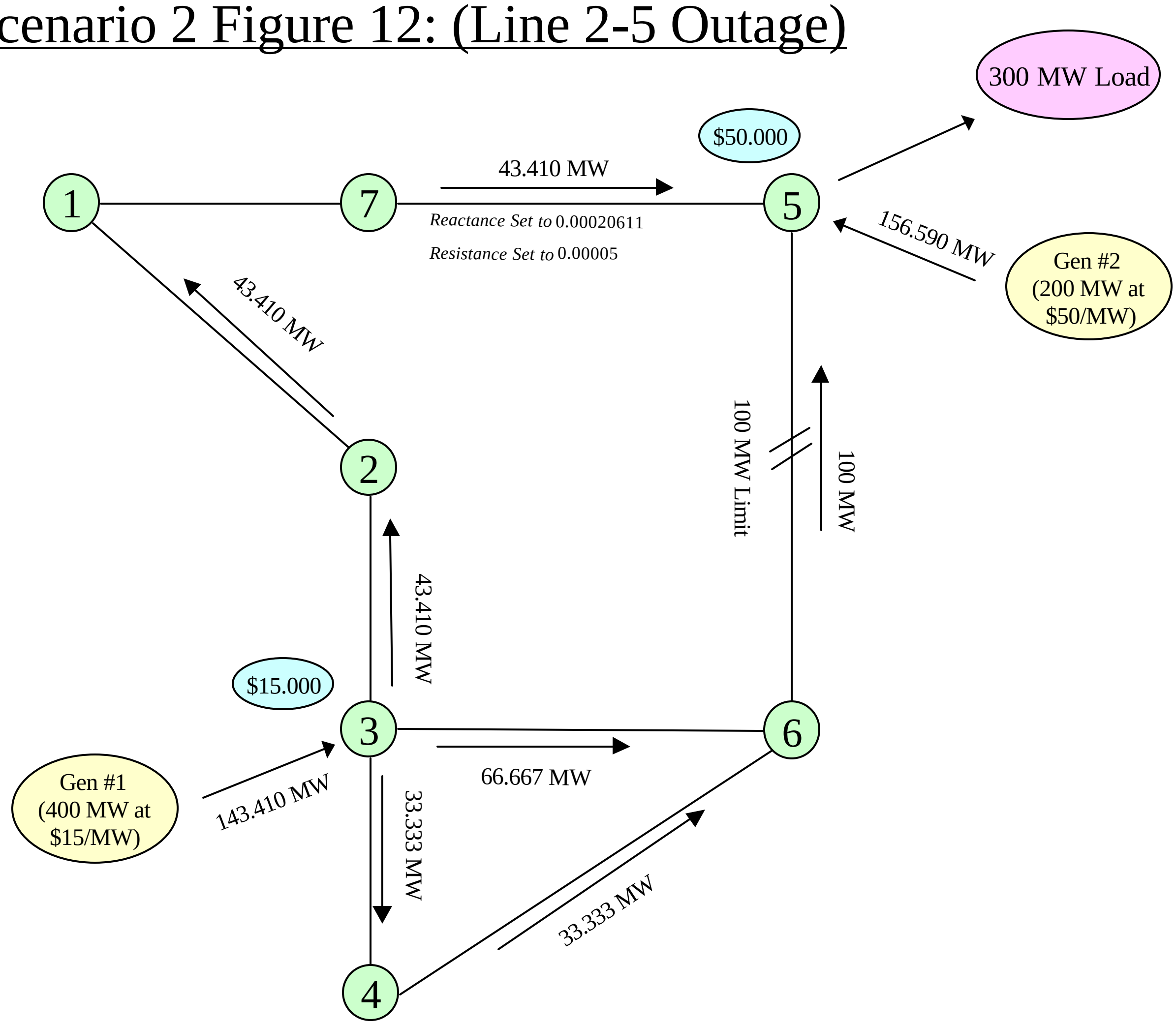
[137] - 1.743 * $50 + .743*$15 = $76.005

It can be further seen in Figure 11 that it is still the case that the outage of the line 7-5 is not a binding contingency.



Finally, Figure 12 portrays the flows following the outage of the line 2-5, which is the binding contingency.

Scenario 2 Figure 12: (Line 2-5 Outage)



In order to realize the full benefits from changes in flows over the controllable line, however, it is necessary in this circumstance for the ISO to not only receive information regarding schedules on the controllable line but also receive information regarding the operation of the controllable line, i.e. resistance and reactance in the case of a PAR controlled line or post-contingency flows in the case of a DC line.

As observed above, the price of power at bus 5 can be readily determined by the basic LBMP pricing equation. In equation [1], the price of power delivered to bus 5 over the controllable line

7-5 is determined by the sum of the reference bus price, losses at bus 5 relative to the reference bus and the sum of the shadow price of the binding constraint times the shift factor on the binding constraint of deliveries at 5 over the controllable line 7-5. If bus 5 were the reference bus and deliveries over the line 7-5 were fixed pre-contingency as in Scenario 1 above, then the shift factor of schedules on 7-5 over 6-5 in the binding contingency would be zero, and the price of power delivered over the line 7-5 would be the price at the reference bus, i.e. bus 5. If deliveries over the line 7-5 rose in the contingency, i.e. as in Scenario 2, then the shift factor of increased deliveries over 7-5 would have a negative post-contingency shift factor over the line 6-5 and the price of power delivered over the line 7-5 would exceed the bus 5 price. In the example in Scenario 2, increased deliveries over the line 7-5 have a negative shift factor of .743 over the line 6-5 in the binding contingency and the price of power delivered over the controllable line is the price at the reference bus ($50 at bus 5) plus .743 times the shadow price of the constraint on line 6-5 ($35/MW).

The other class of pricing outcomes are those in which the outage of the controllable line is one of the binding contingencies. In these cases, the price of power delivered over the controllable line could be lower than the external proxy bus price or higher than the price at the delivery point of the controllable line.

The pricing in these situations is also governed by the generalized formulation in equation [1]. It is again useful to work through simple examples illustrating the basic principles governing price determination.

Figure 13 portrays the pre-contingency flows for Scenario 3. It can be seen that the characteristics of line 2-1 have been changed for this scenario.

Scenario 3 Figure 13: (No Outages)

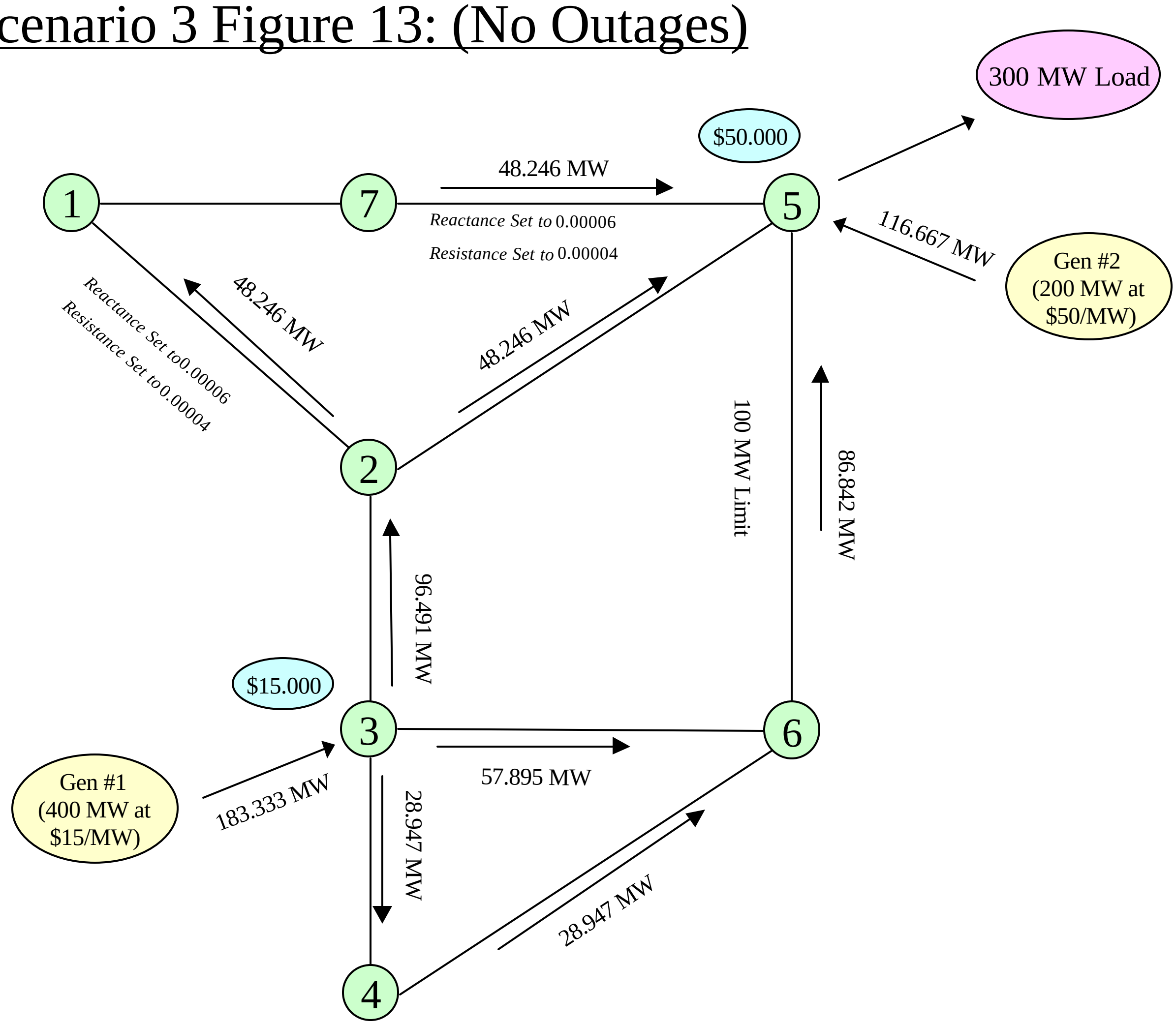


Figure 14 shows the post-contingency flows for the outage of the line 2-5, and it is seen that the limit on flows over the line 6-5 is binding in this contingency.[138]

Scenario 3 Figure 14: (Line 2-5 Outage)

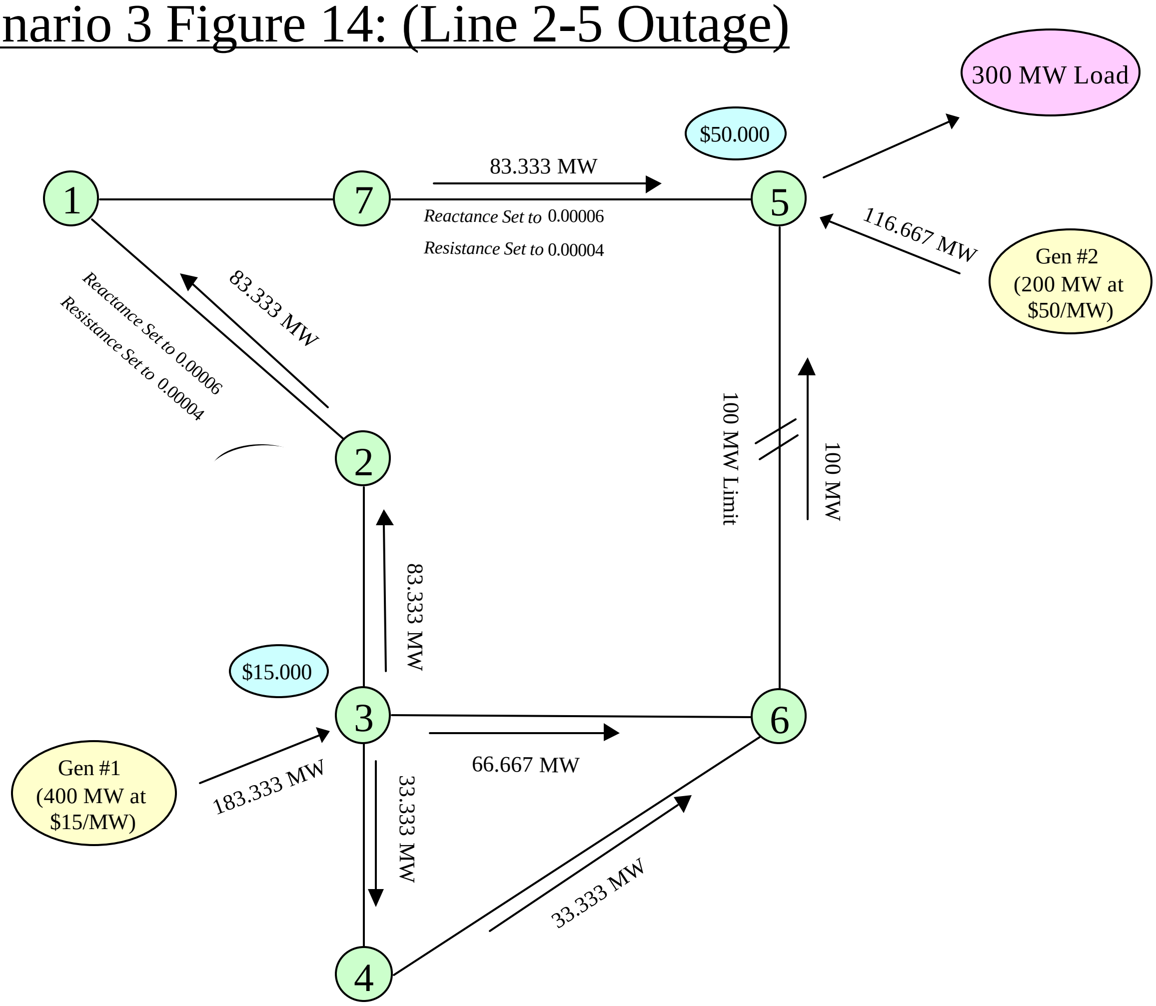
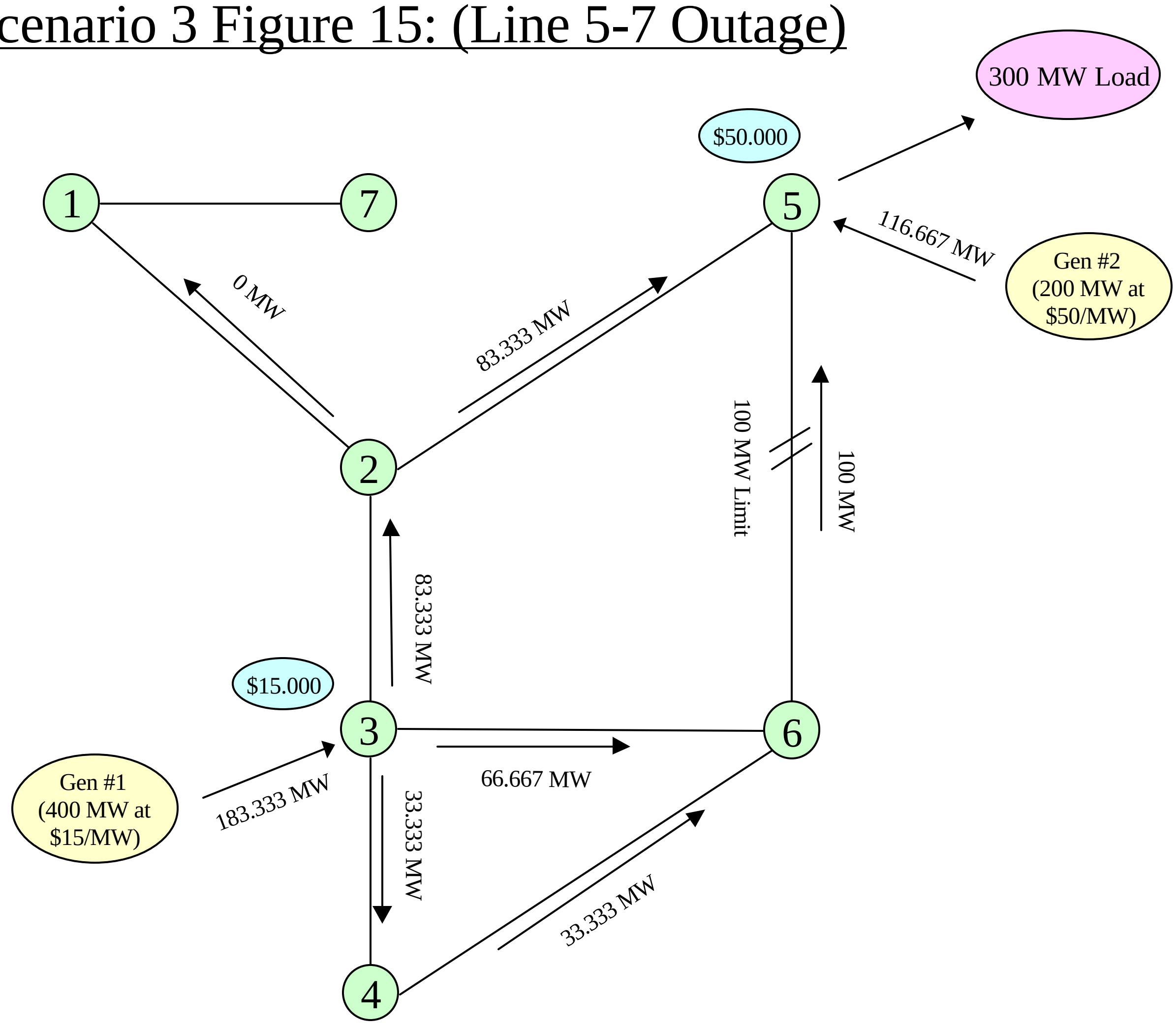


Figure 15 portrays the post-contingency flows following the outage of the controllable line, and it can be seen that flows on the line 6-5 are also at the emergency limit. Thus, no additional flows could be scheduled on the controllable line 7-5 without overloading line 6-5 in the contingency in which line 7-5 is out and no additional flows can be scheduled over the AC ties without overloading line 6-5 in the contingency in which line 2-5 is out. Although there are superficially two binding constraints, one is redundant, and there are only two marginal

[138] If this constraint were not binding, the price at bus 3 would be the same as the price at bus 5, as there would be no constraint on flows over the AC ties.

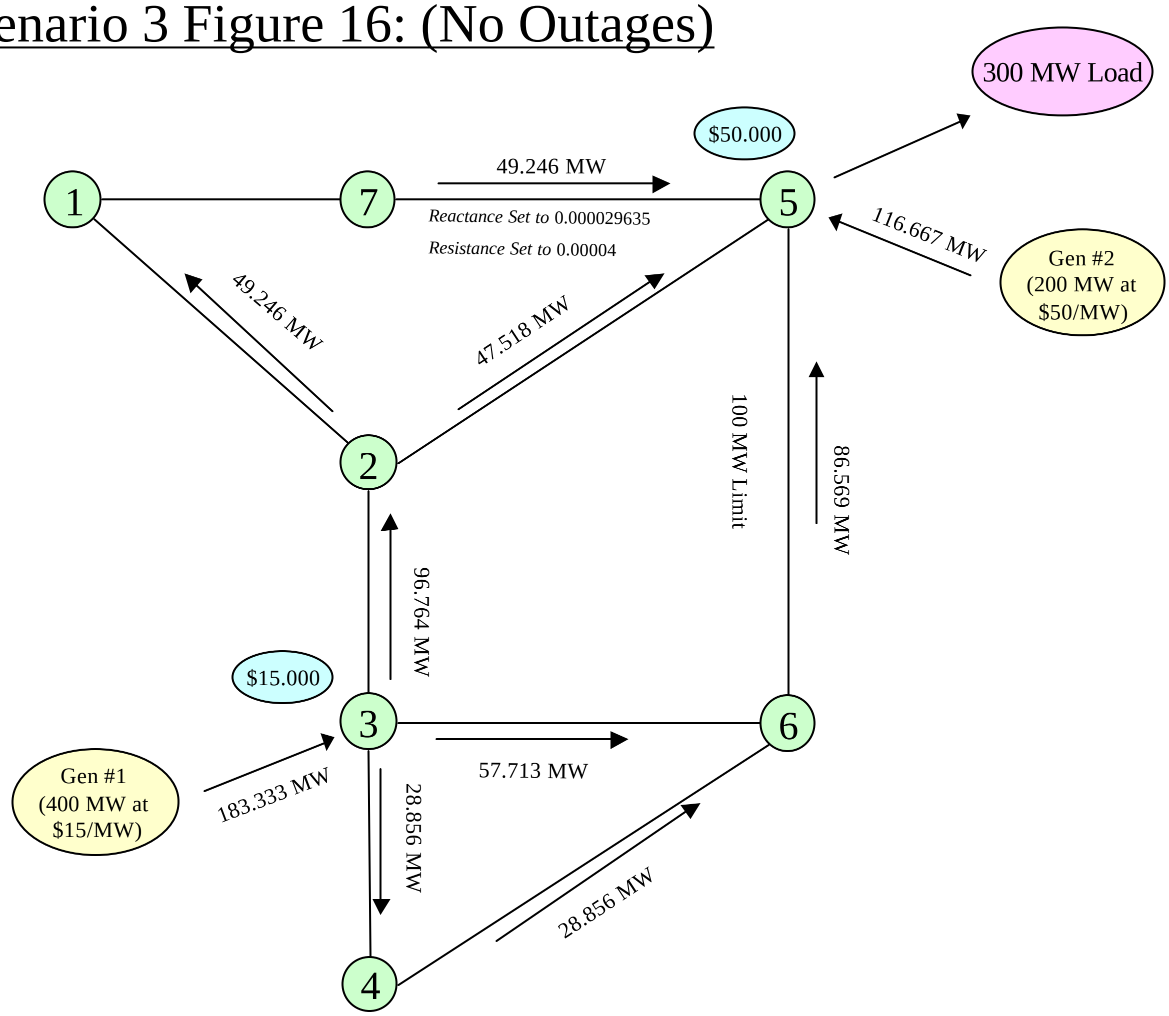
generators: generation at 5 and generation at 3. The flows over the controllable line are not marginal, since it does not matter whether energy is scheduled to flow over the controllable line or AC interconnect.

Scenario 3 Figure 15: (Line 5-7 Outage)



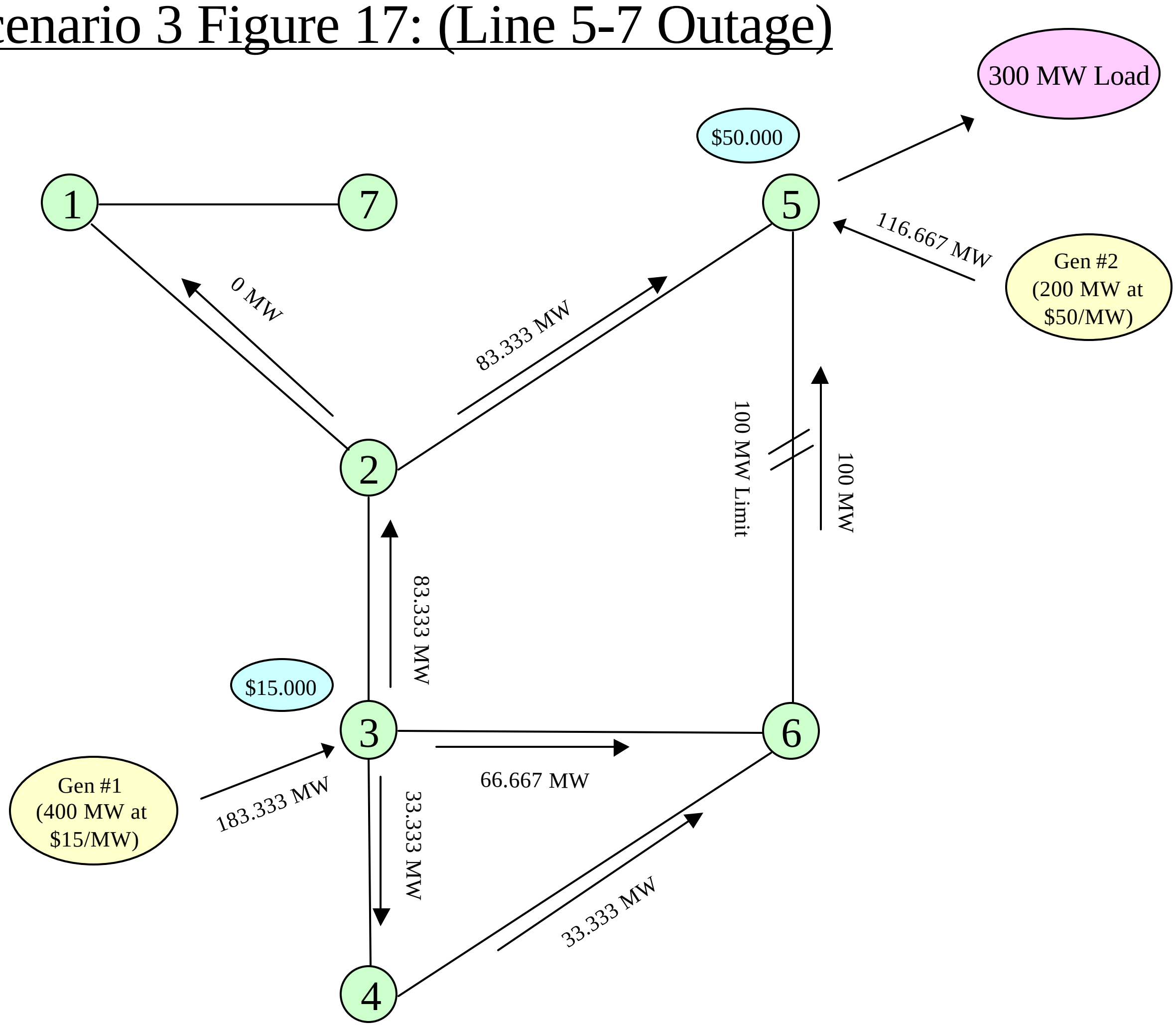
The value of schedules over the controllable line can again be illustrated by considering the impact of a 1MW increase in schedules over the controllable line. Figure 16 shows the pre-contingency flows over this transmission system with schedules over the line 7-5 increased from 48.246 to 49.246. It is noteworthy, however that the injections at bus 3 and bus 5 are both unchanged.

Scenario 3 Figure 16: (No Outages)



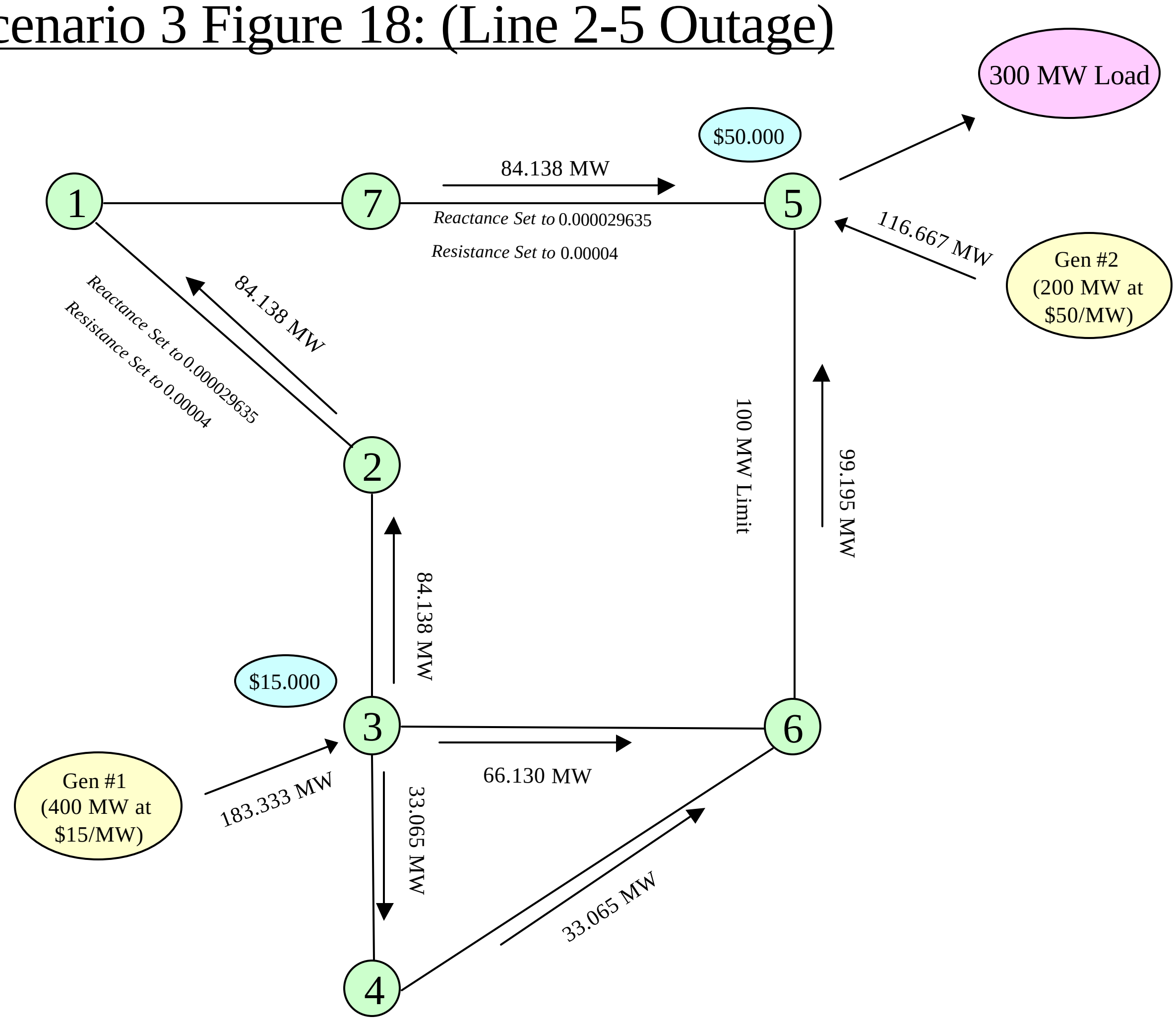
The reason for this outcome is that the outage of the line 7-5 is a binding contingency, and the pre-contingency schedules over line 7-5 are irrelevant in this contingency. This is illustrated in Figure 17.

Scenario 3 Figure 17: (Line 5-7 Outage)



If the schedule on line 7-5 were increased, the outage of line 2-5 would no longer be a binding contingency as illustrated in Figure 18, but this would not change the pricing solution.

Scenario 3 Figure 18: (Line 2-5 Outage)



The proxy bus price (bus 3) would be the price paid to injections at bus 3 flowing over the AC ties. This price would reflect the impact on injections at 3 on line 6-5 both in the contingency in which lie 2-5 is out and the contingency in which line 7-5 is out. Thus, the shadow price on the line 6-5 constraint in the 7-5 contingency is $64.05, and generation at the proxy bus has a .5464 shift factor on that line in that contingency. Importantly, the shift factor of power scheduled over the controllable line is also .5464 in this contingency, as this is the contingency in which the controllable line is out.

III. Operational Rules

Operationally, each ISO could model all generation in the other control area as if it were at a single location, i.e. there could be a single reference bus for scheduling purposes, if this provided the best operational model. It is possible, however, that the ISOs could find that the dispatch required to maintain schedules on the controllable line differs from that required to sustain imports over the AC interconnect and thus that the operational model would be improved by modeling the imports over the controllable line having a different generation source than the imports over the AC interconnects. In this case, the ISOs could adopt a multiple reference bus operational model, with one reference bus for flows over the controllable line and another reference bus for flows over the AC interconnection.[139]

This second reference bus need not, indeed probably would not, be located at the end of the controllable line. Nor would the location of this second reference bus be the same as the pricing point for the controllable line, in fact, it would almost certainly be different.

[139] In principle, there is no reason, other than the informational requirements, why the reference bus for the AC interconnect operational model might not depend on the generation configuration in the adjacent control area if this improved modeling.

APPENDIX II

DRAFT

NOTES ON CONTROLLABLE LINE PRICING

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The use of controllable lines offers different approaches for modeling the network and treating the control parameters. Furthermore, the degree of control may vary. In the case that the line parameters can be set in the dispatch but not changed during contingencies, then the problem reduces to the standard model with the line impedances set to the pre-contingency values. In the case of controllable lines that can maintain flow during a contingency, there is a natural interpretation of the equivalent effect of the controllable line as to create fixed net loads at each end of the line and remove the representation of the line in the network model. Here we outline this latter case and demonstrate the conclusion in terms of the implications for the pricing equations.

The linearized DC-load approximation illustrates the basic structure of the network pricing results that could be extended to include changing grid conditions or nonlinear effects. Define the basic variables as:

d: the vector of bus loads,

g: the vector of bus generation,

y: the vector of net bus loads,

z: the vector of line flows,

θ: the vector of bus angles,

A: the incidence matrix of lines and buses, +1 for sink and –1 for source,

Ω: the diagonal matrix of line admittances.

The corresponding representation of the network flows and constraints under the usual assumptions of the Schweppe lossless DC-load approximation yields:

$$
\begin{aligned}
&d - g = y,\\
&z = \Omega A\boldsymbol{q},\\
&y = A^t z,\\
&z \leq z\max.
\end{aligned}
$$

Hence the flows on the lines are determined by the difference in bus angles at the ends of the line. Total flows in and out of a bus must equal the net loads. Here the constraints are shown as upper bounds on lines. This is a notational convenience, and there is no difficulty including lower bounds or aggregate interface constraints. For computational purposes, it is convenient to include the explicit representation of the angles. However, Schweppe et al. eliminate the angles and produce a representation that relates the net bus loads and line flows. Under the usual assumptions about the arbitrary swing bus where the angle is constrained to zero, for convenience here selected to be the last bus, we let $\tilde{A}$ be the incidence matrix with the last column deleted. Hence $\left(\tilde{A}^t\Omega\tilde{A}\right)$ is invertible. Further let the vector 1 be a column of ones to add up all the net loads in balancing equation. Then we have the equivalent DC-load model:

$$
\begin{aligned}
&d - g = y,\\
&1^t y = 0,\\
&z = \left[\Omega\tilde{A}\left(\tilde{A}^t\Omega\tilde{A}\right)^{-1} \quad 0\right] y,\\
&z \leq z\max.
\end{aligned}
$$

The matrix $SF = \left[\Omega\tilde{A}\left(\tilde{A}^t\Omega\tilde{A}\right)^{-1} \quad 0\right]$ is the set of shift factors that can be interpreted as the marginal change in line flows induced by a marginal change in net bus load balanced at the swing bus.

To incorporate the controllable line in this model, and introduce contingencies at the same time, distinguish between the normal free flowing (ac) lines and the controllable lines (dc) with some device such as a phase angle regulator or a DC transformer that is able to fix the flows. Each contingency, indexed by i, yields a different set of parameters. For example, if a line is out, the corresponding row of the incidence matrix is set to zero.

One approach to modeling controllable lines would be treat the respective elements of Ω as variables and adjust them to achieve the intended flow on the controllable lines for the given angle differences. The equivalent alternative used here is to model the controllable flows directly as variables that are independent of the bus angles. This latter approach produces the same results but makes the pricing equation more transparent.

The resulting contingency-constrained modification of the network variables and constraints is:

$$
\begin{aligned}
& d-g=y, \\
& z_{ac}^i=\Omega_{ac}^i A_{ac}^i \theta^i, \quad \forall i, \\
& y=\begin{bmatrix} A_{ac}^{i\ t} & A_{dc}^{i\ t} \end{bmatrix}\begin{bmatrix} z_{ac}^i \\ z_{dc} \end{bmatrix}, \quad \forall i, \\
& z_{ac}^i \leq z\max_{ac}^i, \quad \forall i, \\
& z_{dc} \leq z\max_{dc}.
\end{aligned}
$$

Here the angles and network loop flow conditions apply only to the free flowing lines. The free-flowing line flows can be different in every contingency, but the controllable line flows are assumed to be the same. The loss of the controllable line removes the effect of these flows by zeroing out the corresponding row in the incidence matrix. If we follow the same development as Schweppe, we get the set of contingency constraints and flows as in:

$$
\begin{aligned}
& d-g=y, \\
& 1^t y=0, \\
& z_{ac}^i=\left[\Omega_{ac}^i \tilde{A}_{ac}^i\left(\tilde{A}_{ac}^{i\ t} \Omega_{ac}^i \tilde{A}_{ac}^i\right)^{-1} \quad 0\right]\left[y-A_{dc}^{i\ t} z_{dc}\right], \quad \forall i, \\
& z_{ac}^i \leq z\max_{ac}^i, \quad \forall i, \\
& z_{dc} \leq z\max_{dc}.
\end{aligned}
$$

With these constraints, we can formulate an optimal dispatch problem with benefit (B) and cost (C) as:

$$
\begin{aligned}
& \underset{d, g, y, z_{ac}^i, z_{dc}}{Max} \quad B(d)-C(g) \\
& s.t. \\
& d-g=y, \\
& 1^t y=0, \\
& z_{ac}^i=\left[\Omega_{ac}^i \tilde{A}_{ac}^i\left(\tilde{A}_{ac}^{i\ t} \Omega_{ac}^i \tilde{A}_{ac}^i\right)^{-1} \quad 0\right]\left[y-A_{dc}^{i\ t} z_{dc}\right], \quad \forall i, \\
& z_{ac}^i \leq z\max_{ac}^i, \quad \forall i, \\
& z_{dc} \leq z\max_{dc}.
\end{aligned}
$$

Or, to put it in more conventional terms with the shift factors, we have:

$$
\begin{aligned}
&\underset{d,g,y,z_{ac}^{i},z_{dc}}{Max} \quad B(d) - C(g) \\
&s.t. \\
&\qquad d - g = y, && \boldsymbol{l} \\
&\qquad 1^{t} y = 0, && p_{swing} \\
&z_{ac}^{i} = SF_{ac}^{i}\left[y - A_{dc}^{i\,t} z_{dc} \right], \quad \forall i, && \boldsymbol{j}_{ac}^{i} \\
&\qquad z_{ac}^{i} \le z\max_{ac}^{i}, \quad \forall i, && m_{ac}^{i} \\
&\qquad z_{dc} \le z\max_{dc}. && m_{dc}
\end{aligned}
$$

With this formulation of the security constrained economic dispatch problem, including the respective shadow prices, we have the associated locational prices (p) determined from the first order optimality conditions as:

$$
\begin{aligned}
&p = \nabla B = \nabla C = \boldsymbol{l}, \\
&\boldsymbol{l} = p_{swing} 1 + \sum_{i} SF_{ac}^{i\,t} \boldsymbol{j}_{ac}^{i}, \\
&\boldsymbol{j}_{ac}^{i} = m_{ac}^{i}, \\
&\sum_{i} A_{dc}^{i} SF_{ac}^{i\,t} \boldsymbol{j}_{ac}^{i} = m_{dc}.
\end{aligned}
$$

If we eliminate the intermediate shadow prices, we obtain the usual pricing equations for the marginal effects on the AC network based on the shadow prices for the binding constraints. We can also see the connection to the shadow prices on the limits for the controllable line.

$$
\begin{aligned}
&p = \nabla B = \nabla C = p_{swing} 1 + \sum_{i} SF_{ac}^{i\,t} m_{ac}^{i}, \\
&\sum_{i} A_{dc}^{i} SF_{ac}^{i\,t} m_{ac}^{i} = m_{dc}.
\end{aligned}
$$

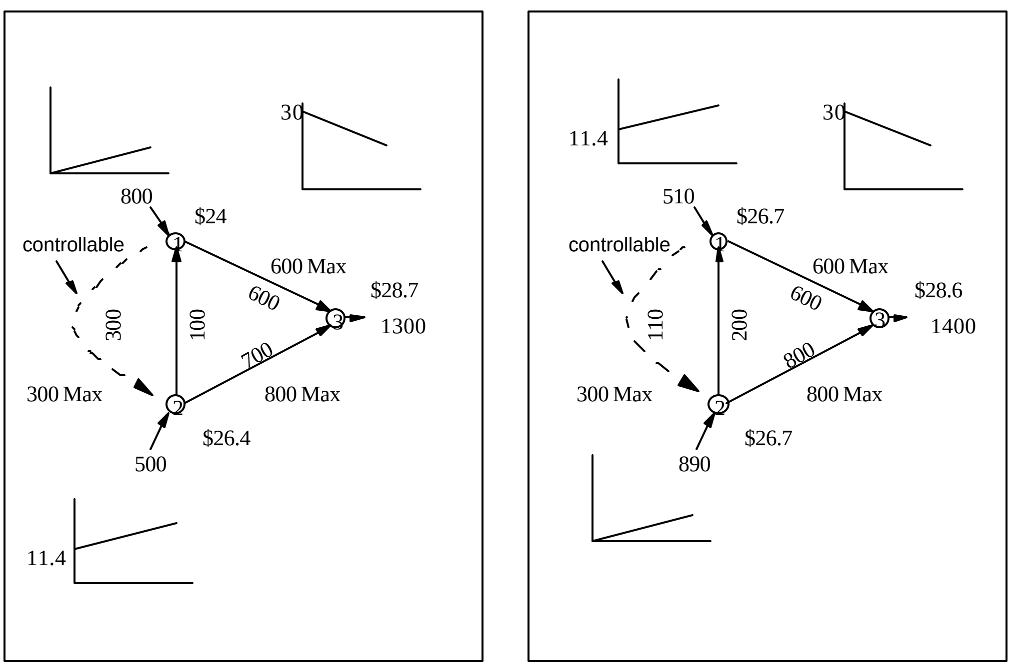
In what can be viewed as an application of the envelope theorem, or the superposition property of the DC-load approximation, we find the locational pricing equation as the same format as the case with the controllable lines removed. In effect, given the optimal solution, the controllable lines could be modeled in the DC-load formulation as fixed net loads at each end of the line.

The price of the limit on the controllable line is the contribution to the difference in the locational prices at either end for all the contingencies in which the controllable line is in service. Note that in the case of the controllable line being out of service, the corresponding elements of the incidence matrix are zero and there is no contribution to the prices. Unlike the case for free flowing lines, if the controllable line outage is not a binding contingency, then either the controllable line constraint is binding or the prices are equal at both ends of the line.

To illustrate the effect of controllable lines, consider the hypothetical network in the two panels of the accompanying figure. Here the network consists of three lines and three buses that follow the assumptions of the DC-load model. The lines are identical except for different limits as shown in the figure. Hence the distribution factors for this part of the network must be 1/3 and 2/3. For the three-line network, 2/3 of the power moving from bus 1 to bus 3 would flow over the line between them, and 1/3 would flow over the other path through bus 2. Symmetrically, 2/3 of the power moving from bus 2 to bus 3 would flow over the line between them, and the remaining 1/3 would flow over the other path through bus 1.

In addition, there is a controllable line between bus 1 and bus 2, as indicated by the dashed line in the two panels.

Controllable Line and Transmission Congestion



For purposes of this example, we assume that the controllable line is able to move up to 300 MW in either direction. The two panels show two different sets of supply curves and the corresponding optimal solutions that yield for each a market equilibrium with the corresponding locational prices.

If we arbitrarily choose bus 3 as the swing bus, then the sign conventions and definitions used here give the of corresponding shift factors for the free flowing network as

		SF		
	Bus	**1**	**2**	**3**
Line	**1->3**	- 2/3	- 1/3	0
	1->2	- 1/3	- 1/3	0
	2->3	- 1/3	- 2/3	0

In the left panel, the shadow price on line 1->3 is 7.02. Hence, the congestion impact of load is -0.3333*7.02=-2.34 at bus 2 and -0.667*7.02=-4.68 at bus 1. The corresponding shadow price of the constrained controllable line is the difference of 2.34=-2.34-(-4.68).

In the right panel, the shadow price is 1.9 for both the limits on line 1->2 and the limit on 2->3. The corresponding congestion impact at bus 1 and bus 2 is therefore -0.333*1.9-0.667*1.9 = -1.9. The corresponding shadow price on the unconstrained controllable line is zero, and the prices at both ends are the same at $26.7.

Choosing the first bus as the swing bus would change the signs of some of the shift factors, but this would not change any of the resulting locational prices or the price of the constraint on the controllable line.