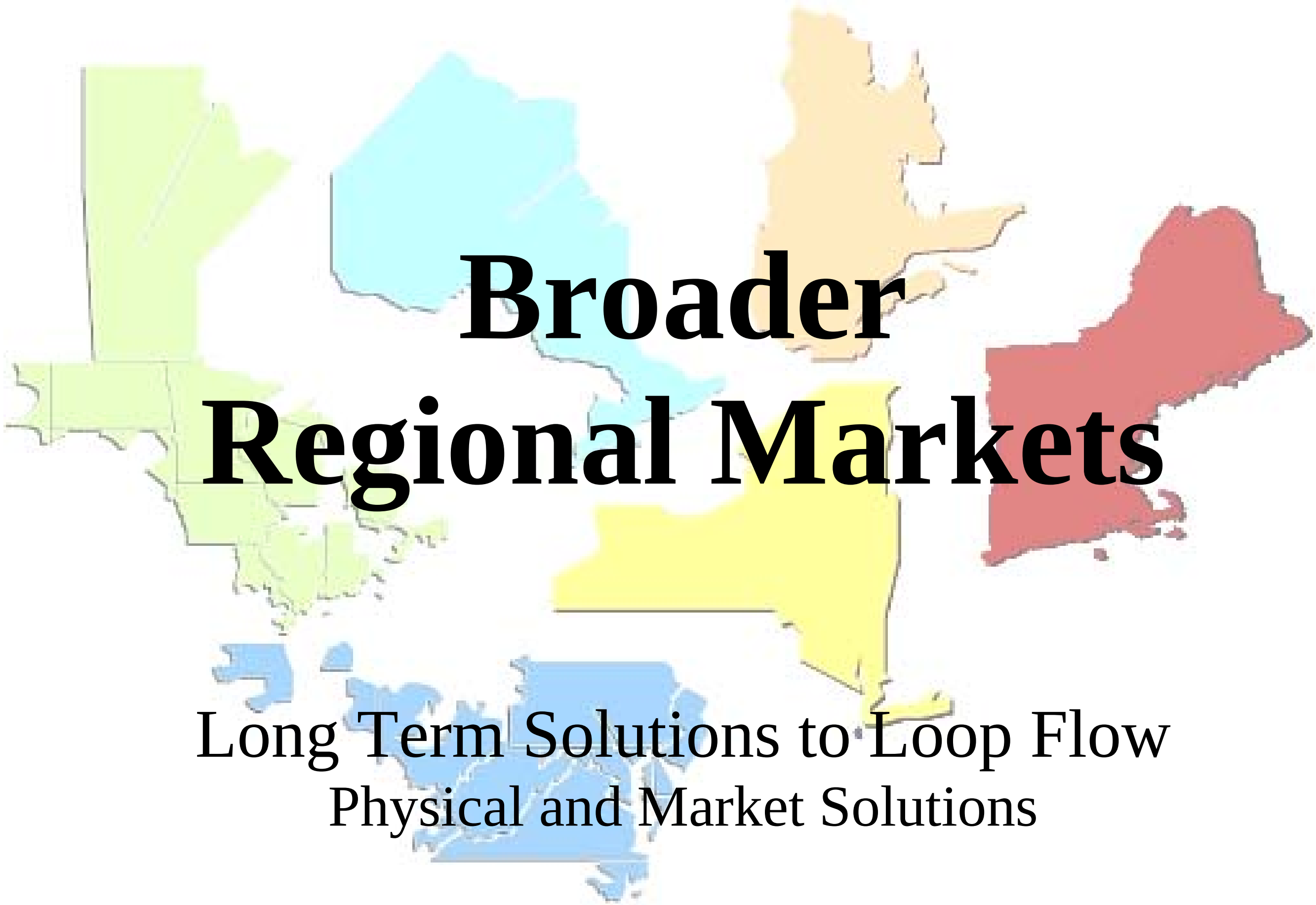
# Attachment A

# Broader Regional Markets,
# Long-Term Solutions to Lake Erie Loop Flow
# White Paper



# Broader Regional Markets

## Long Term Solutions to Loop Flow

### Physical and Market Solutions

**All information contained in this draft paper is a work-in-progress and is distributed for discussion and information purposes only. Responses and feedback are requested on the concepts captured within this document. The document shall be revised as the development and review of the proposals progresses.**

# TABLE OF CONTENTS

## 1. Summary

The desire of participants in ISO and RTO energy markets and in non-market areas is for a buyer and a seller to agree on a price and a quantity of electricity commodity and to deliver that quantity over the network from the place where it is produced to the place where it will be resold or consumed. The electric industry for years has grappled with the problem that electric power does not flow as requested on the grid, but rather, as described in Ohm's law, flows along the path of least resistance. The configuration of any and every element of the electric grid determines this resistance or impedance that governs the flow of electricity.

The disconnect between the "contract path" between source and sink becomes a reliability concern when the attempt to dispatch scheduled flows negatively impacts the system by creating actual flow patterns that are significantly different from scheduled flows due to the physical reality of the transmission system. The unscheduled flow patterns can load transmission facilities beyond their rated capacity even though these facilities could accommodate the nominal quantity scheduled for transfer had the actual flows matched those scheduled.

Unscheduled energy, also known as "loop" flow and "circulation" flow, results from the difference between the energy that is scheduled to flow across an interface connecting two balancing areas versus the amount of energy that actually flows across the interface between those two balancing areas. In addition, loop flows are caused by a balancing area's generation to load dispatch when a portion of the resulting flows travel over neighboring systems.

On July 21, 2008, to address the escalating impact of loop flows on its transmission system the NYISO filed tariff provisions at FERC that preclude the scheduling of transactions via circuitous paths around Lake Erie. A goal of these provisions was to increase consistency between the scheduling path and actual path of real power flows, thereby better aligning cost causation and cost allocation. The prohibitions were necessary, as there were no other adequate physical or market mechanisms readily available to control, or direct, physical real power flows around Lake Erie, or to permit recovery of costs when scheduled and actual power flows were not aligned. The Broader Regional Markets initiatives capture the desire to develop a more complete response to loop flows and the address the inconsistencies between contract path scheduling and actual flow of power. Lake Erie loop flows may remain as a practical reality of interconnected system operation. The accurate recognition and accounting of the costs incurred throughout the region in managing those flows must still be addressed.

The NYISO and its neighbors (IESO, MISO, PJM, ISO-NE and HQ) are working together to remove barriers to a broader regional market that spans balancing area boundaries and to improve the efficiency of electricity exchange in our region. This paper outlines market and physical solutions which have significant merits and that are expected to collectively result in vastly improved efficiency of the energy markets and transmission utilization on a regional basis. Improved regional efficiency will be achieved through coordinated operation of resources across markets to manage transmission congestion and improve transaction scheduling outcomes given market-to-market prices.

NYISO is working with its neighboring ISO/RTOs on specific market solutions including the: (1) Buy-Through of Congestion, (2) Congestion Management, and (3) Interregional Transaction Coordination solutions that are described below. Additionally, IESO and MISO are pursuing the implementation of Phase Angle Regulator (PAR) devices on the free flowing ties between Ontario and Michigan to improve control of flows on the facilities to align with schedules.

It is the recommendation of the ISO/RTOs that the preferred outcome is achieved through the collective implementation of all of these initiatives. Individually, they each only address a component of Lake-Erie loop flows and the efficiencies of a broader regional market. Buy-Through of Congestion responds to off-contract path transaction scheduling congestion management cost recovery, but does not address generation impacts on the network. Congestion Management enables more efficient use of limited transmission resources by providing compensation to generation resources to resolve system constraints. Finally, Interregional Transaction Coordination allows for more frequent region-to-region interchange to address similar resource limitations. The combined capabilities of the proposed solutions offer the potential to reduce uplift costs associated with real-time event management and congestion management; to improve the capability to incorporate intermittent resources, and to lower total system operating costs. The goal is to design the improvements in such a manner that they can be incorporated into the various ISOs and RTOs respective market designs without the need for fundamental changes to the rules that underlie the various interconnected markets.

## 2. **Objectives**

The set of solutions proposed in the document were developed to achieve a set of objectives that will lead to improved operational and market outcomes. Those objectives, as well as how the solutions collectively achieve those objectives is as follows:

- Reduce need for, frequency of, and magnitude of Transmission Loading Relief (TLR) events to address loop flow.
    - While TLR events are effective at addressing reliability constraints, they can result in significant levels of transmission service curtailment, disrupting the system operations and markets of the regions subject to the curtailments as they attempt to replace the removed energy and potentially significantly distorting the markets from their expected condition. Buy-Through of Congestion provides an economic selection based solution by creating the economic indicators necessary to avoid these scenarios either by discouraging the scheduling of power to these levels due to the high costs of managing these constraints, or by ensuring that the constraint management cost recovery mechanisms are available.

- Align constraint management cost recovery with sources of flow on the congested flowgate.
    - Addressing system reliability overloads requires the dispatch of otherwise off-cost generation to alleviate the flow constraints and a resulting increase in costs to that region. Parallel Flow Visualization and Buy-Through of Congestion facilitate the identification of the sources of loop flow and the allocation of the congestion management costs incurred to support these flows to those that are responsible for creating them.

- Reduce constraint management costs for consumers across region.
    - Congestion Management achieves a more cost effective resolution of system constraints by expanding the pool of assets that are capable of addressing the constraint. The availability of more cost effective solution options results in lower costs of constraint management.

- Improve regional price consistency and transmission utilization.
    - Congestion Management provides for more consistent prices across the borders as the collective assets are utilized to resolve system limitations.
    - Interregional Transaction Coordination provides the additional flexibility to adjust interchange schedules more frequently in response to changing market conditions, including the impacts resulting from increased intermittent power resources. More frequent adjustment of schedules

results in more consistent flow of energy in response to differences in prices between regions and lowers risk in scheduling decisions.

## 3. Physical Solutions

In the absence of a single ISO/RTO dispatching resources across the broad region surrounding Lake Erie, better conformance of actual power flows to scheduled power flows across the key interconnections is a desirable component of any plan to address the Lake Erie loop flow issue. Better matching of flows to schedule can be achieved through the use of "physical," i.e. transmission system equipment, solutions.

One solution is the use of a phase shifting transformer, also referred to as a Phase Angle Regulator ("PAR".) Such "controls" are in the process of being installed on the interconnection between Ontario and Michigan in order to mitigate inadvertent loop flows that can result in one party benefiting from services provided by another.

Implementing an effective regional physical solution to control or mitigate Lake Erie circulation should be a key component of any comprehensive solution that the NYISO and its neighbouring ISOs and RTOs develop. Using the Ontario-Michigan PARs to more closely match actual power flows to scheduled power flows will reduce unscheduled Lake Erie loop flows and their corresponding impact on congestion management costs and LBMP prices.

### a. Ontario – Michigan Phase Angle Regulators

It is recognized that better conformance of actual power flows to scheduled power flows across the New York - Ontario and Michigan - Ontario interconnections is a desirable component of any plan to address the Lake Erie loop flow issue. In its August 21, 2008 Order in docket ER08-1281-000, the FERC reinforced this by encouraging the parties responsible for operating the Ontario-Michigan PARs to place them in service as soon as practical.

#### i. Installation

During 1999, the completion of international negotiations enabled work to commence on the installation of phase-shifting transformers (Phase Angle Regulators or PARs) and an autotransformer at the interconnection between Michigan and Ontario. This equipment was designed to both increase the import/export capacity of the interconnection and also to provide a means to manage loop flows through Ontario often referred to as Lake Erie Circulation (LEC). Implementation of this physical solution will go a long way toward reducing unscheduled, circulating power flows around Lake Erie. Ongoing operation of these facilities has been delayed due to a number of equipment failures, events and difficulties in getting operating agreements in place between the parties.

The failed equipment has been replaced and further protection upgrades to allow operation of the equipment are being completed. The latter is scheduled for completion by the end of the first quarter 2010, with (full) operation of the phase angle regulators anticipated to commence shortly thereafter.

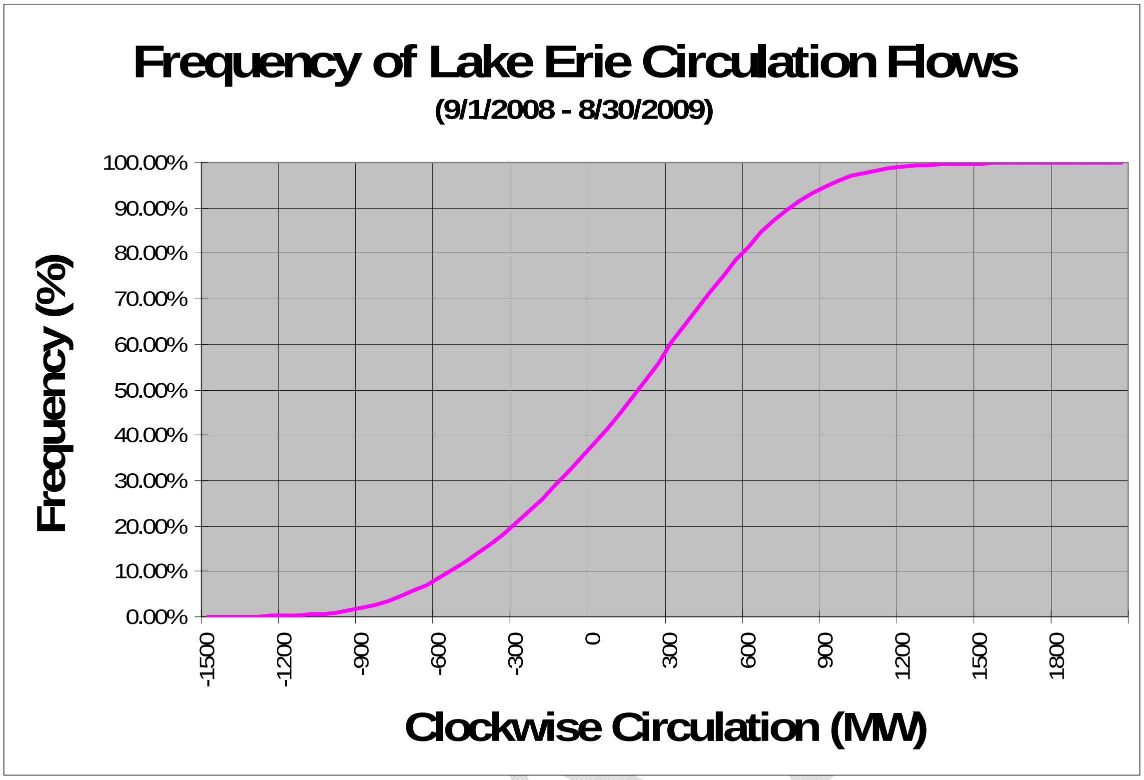
ii. Operating protocol

The operating protocols for the Michigan-Ontario PARs have been developed between ITC, MISO, and the IESO and are awaiting signature. They are to incorporate controlling actual flow to match scheduled interchange as provided under existing Presidential Permit PP-230-3.

Under normal system conditions, the phase-shifting transformers on the interconnection between Michigan and Ontario are to be operated such that the electrical flow on the Michigan-Ontario interface will, as far as practical, match the scheduled transactions across the Michigan-Ontario interface. Under emergency conditions, the phase-shifting transformers shall be operated in a manner that will help alleviate such emergencies consistent with good utility practices.

iii. Expected capabilities

The utilization of the Michigan-Ontario PARs will help to control a loop flow or a parallel path flow called Lake Erie Circulation (LEC). These PARs, with an effective phase angle control range of ±47 degrees under full load, are expected to be capable of controlling Lake Erie Circulation by up to approximately 600 MW in either direction. Control of Lake Erie Circulation to such levels should better enable scheduled power flows to be maintained between Ontario, Michigan and New York. The improved control over power flows should also greatly reduce the incidence of constrained operation on other southern Ontario interfaces affected by loop flow. A sample of historical flow distribution for LEC is shown in the figure below.




Note: Clockwise circulation is evidenced by Michigan to Ontario to New York flows in excess of schedule.

### b. Coordination Operation of Power Control Devices

The operation of the Phase Angle Regulators (PARs) by the four markets around Lake Erie can influence the amount of circulation flows. PARs are electro-mechanical devices that change the impedance on the system. They neither create flows nor absorb flows (except for insignificant losses). PARs can be used to alter the flows to follow a different electrical path or to better follow the contract path, as in the planned Ontario-Michigan PARs. There are a number of operating limitations that prevent the use of PARs to eliminate circulation flows altogether. Since Coordinated operation of the PARs in the four markets around Lake Erie can enhance the degree to which circulation flows are managed, it is important that the operation of PARs by the four markets around Lake Erie be coordinated and included in the long term solutions to loop flows. In addition to PARs, variable frequency transformers, series capacitors, and other such devices have the ability to alter flows that should be coordinated and included in solutions to loop flows.

The PARs that operate around Lake Erie include the PJM and NYISO interface ties at Waldwick (JK), Linden and Hudson (ABC) and Ramapo, the NYISO and IESO interface ties at St. Lawrence and the IESO-MP and IESO-MH interface ties. Of the four ties between MECS and IESO, one is controlled by a PAR (J5D) and the other three do not currently operate with a PAR (the two PARs at Lambton are in bypass and replacement B3N PARs have been installed).

Except for the PARs on the IESO-MP interface and the IESO-MH interface, most PARs are not currently operated to continuously control flows such that schedule flow equals actual flow across an interface. However, most PARs were installed to address a very specific condition and are usually successful managing that one specific condition. As conditions change such that managing that one specific condition is no longer needed, it is very difficult to have the PARs operate in a manner that is different than their design. A loop flow study report issued by Midwest ISO and PJM in May 2007 (http://www.jointandcommon.com/working-groups/joint-and-common/downloads/20070525-loop-flow-investigation-report.pdf) found a strong correlation between the operation of the PARs around Lake Erie and circulation flows. Under ideal conditions, the PARs would be operated such that they always minimize circulation flows. As stated previously, there are operating limitations on how much power can be controlled by a PAR, there are restrictions on the number of tap movements allowed per day and there are dead bands used to delay the response of the PAR. All of these real-world issues prevent operating the PARs under ideal conditions. Since the PARs are not going to always be able to minimize circulating flows and are not able to operate continuously under ideal conditions, it is important that the contributions to circulation flows be identified in the IDC. Under this scenario, the PARs are allowed to operate in accordance with their design requirements and contractual obligations. However, the impact of PAR operation to the contributions to Lake Erie loop flow needs to be identified so that everyone joins in managing these flows during periods when congestion exists.

Two key recommendations in the 2007 study are:

- IESO and NYISO report their market flows to the IDC (or the necessary data for the IDC to calculate the market flow) and participate with Midwest ISO and PJM to manage circulation flows around Lake Erie when congestion occurs.

- The four parties around Lake Erie develop a comprehensive plan on the operation of the Michigan-Ontario and NYISO/PJM PARs to control loop flows around Lake Erie.

In support of the May 2007 MISO, PJM study recommendations and to continue the advancement of regional PAR coordination efforts the following activities will be completed:

- A regional study will be initiated during 2010 to identify reliability and market impacts of the PARS or other controllable devices having a regional impact on Lake Erie loop flows. This study will also identify significant regional paths or flowgates impacted by Lake Erie loop flows.

- Upon completion of the analysis and necessary updates to the existing FERC approved PAR Operating Protocols, regional operating guide recommendations will be developed and implemented by the four parties to better manage Lake Erie loop flow through the coordinated operation of the identified significant controllable devices. This includes implementing the necessary communications infrastructure and regional business processes to facilitate regional coordination of the identified controllable devices.

### c. NYISO Circuitous Path Prohibitions

The NYISO tariffs currently contain provision which preclude the scheduling of transactions via eight circuitous paths around Lake Erie. Inconsistencies between external proxy pricing methodologies between PJM and NYISO led traders to schedule transactions on a contract path that was significantly different than the actual power flow conditions. Subsequent investigations determined that regardless of the pricing provisions, traders had the opportunities to disguise the ultimate source or sink of their transactions to achieve desired settlement outcomes. The NYISO's circuitous scheduling path prohibition was necessary as there were no other mechanisms readily available to the NYISO either to control, or direct, physical real power flows around Lake Erie, or to recover costs when actual and scheduled power flows were not aligned.

The NYISO believes that the existing NYISO prohibition on scheduling via the circuitous paths around Lake Erie is compatible with, and comparable to the outcomes achieved with tag-based pricing. The NYISO acknowledges that traders follow market signals and may be unaware of the resulting actual power flow on the network. The NYISO is currently unaware of any benefit, market or reliability based, to be achieved by allowing transactions to be bid on a path inconsistent with the predominant flow of power.

The purpose of the solutions defined in the remainder of this paper is to provide mechanisms to either control actual power flow to better match scheduled power flows or to more accurately price, assign and recover congestion costs at times when actual power flows diverge from scheduled power flows. The possible removal of the current prohibition on scheduling transactions via circuitous paths around Lake Erie will be considered after validating the completeness of the solutions proposed herein following their implementation.

### d. ATC/AFC Coordination

Current TTC/ATC/AFC calculations and coordination between the New York Independent System Operator (NYISO) and PJM Interconnection (PJM) is performed as specified in Article Thirteen of the NYISO/PJM Joint Operating Agreement. This agreement specifies that both parties will exchange scheduled outage information on all interconnection and other transmission facilities that have the potential to impact TTC/ATC/AFC values and will also exchange the projected status of scheduled outages of those same transmission facilities for a minimum of eighteen (18) months or more if available. The Parties also exchange interchange schedule information to permit the calculation of TTC and ATC/AFC values. This agreement also calls for each Party to provide the other with transmission configuration changes and generation additions and retirements.

Transmission system impacts are also coordinated as needed and with other Reliability Coordinators, Balancing Authorities, and Generator Operators as needed to develop and implement action plans to mitigate potential or actual Security Operation Limit (SOL), Interconnection Reliability Operation Limit (IROL), Control Performance Standard (CPS), or Disturbance Control Standard (DSC) violations. In instances where there is a difference in derived limits, both parties respect the most limiting parameter. A Party who foresees a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) that impacts the other Party issues an alert to the other Party without unreasonable delay. Both Parties confirm reliability assessment results and determine the effects of operational issues within its own and the other Party's areas. The Parties discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection and in line with NERC reliability standards at all times.

Current TTC/ATC/AFC calculations and coordination between the Midwest ISO and PJM are conducted in a similar fashion as described above, and are performed in addition to calculations in support of the Congestion Management Process in place between the Midwest ISO and PJM. The Congestion Management Process requires the establishment of Firm Flow Limits on Coordinated Flowgates. This calculation determines the directional market flow impacts on all Coordinated Flowgates and is used to determine the portion of those flows in each direction that should be considered Firm and Non-firm for both the current and next hour. Additionally, as frequently as once per hour, but no less frequently than once every three months, each Party submits to the Reliability Coordinator sets of data describing the marginal units and their associated participation factors for generation within the market footprint. This data is used by the Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

This additional Congestion Management Process effectively extends the value of the TTC/ATC/AFC calculation processes by including generation impacts on constrained flowgates which can be dispatched to maximize the use of constrained transmission facilities and minimize the need to use TLRs to control transmission congestion created by loop flows.

Each of the ISOs have established market mechanisms for reviewing and approving firm flow transaction requests. All of the offerings accomplish the tasks of observing the physical capabilities of the system, valuing that service and offering the hedging opportunities of the potential observed costs of transmission congestion within that ISO. While incremental improvement opportunities may exist to the allocation process, the opportunities are not seen as a solution to loop flows or to system congestion. Loop flow exists due to the interconnected nature of the power systems and the need to maximize the value of that system to move lower cost power to the consumers.

## 4. Market Solutions

### a. Parallel Flow Visualization

Network flows on an interconnected grid are the composite result of all the individual actions taken in the interconnected regions to dispatch generation to meet their load, to direct flow on controllable facilities, and to transfer energy between regions. No single region currently has access to sufficient information to decompose line and flowgate flows into the unique sources of those flows.

The goal of a market flow calculator is to facilitate the calculation of impacts, to assemble the necessary real-time data, to perform the generation-to-load calculations and to make available common and consistent information regarding the sources of power flows and their impacts available to all regions. The market flow calculator will distinguish the source of flow between (A) each separate region's impacts associated with generation-to-load dispatch and (B) individual transaction impacts.

Pseudo ties, used for extending regions boundaries, will be included in generation-to-load calculations. Pseudo ties are not tagged and are modeled in the IDC consistent with dispatches of internal resources. Dynamic schedules are identified for curtailment purposes via NERC tags and would be visible to the IDC process as an interchange schedule. These impacts would be included in transaction impacts, not generation-to-load impacts.

The NERC IDC Working Group is currently tasked with defining the necessary data reporting requirements and developing with OATI the specification for performing a market flow calculation. Data reporting by the Balancing Authorities will become required to support the accurate computation of market flows.

The future market flow calculation process will require significantly more data at a greater frequency. The magnitude of the expected benefits will be tied to the quality of the data reporting. The collective ISOs support the accurate, complete and timely reporting of the necessary information to achieve the region wide implementation of the parallel flow visualization process and the visibility it provides to market flow impacts. The availability of this information is required to support the implementations of Congestion Management and Buy-Through of Congestion and the management of Lake Erie loop flows. In the absence of a NERC supported solution, alternative solutions will need to be developed to achieve this information reporting. To support the collective ISOs commitment to a timely implementation of the market solutions, the ISOs will evaluate by June 1st 2010 the state of the Parallel Flow Visualization implementation. If the solution is determined to be abandoned, unsupportable, or unachievable, the ISOs will pursue alternative solutions to the visibility initiative in an effort to maintain the proposed solutions implementation timelines.

i. Interchange Distribution Calculator (IDC) Data Reporting

Identifying the transactions associated with unscheduled flows within the IDC is a key element to the solutions identified within this white paper. Reliability Coordinators monitor real-time flows using RTCA and SCADA. This process is effective monitoring total flow but does not identify the source and magnitude of parallel flows.

A comprehensive parallel flow visualization motion was approved at the May 6, 2009 NERC Operating Reliability Subcommittee (ORS) meeting. Highlights of proposal included:

- RCs would report their generation-to-load impacts to the IDC on a real-time basis or make arrangements to have someone report on their behalf.
- The IDC would indicate the source or all flows on a flowgate and the priority of these flows (tag impacts, generation-to-load impacts and market flow impacts).
- An RC experiencing congestion would have visualization of the magnitude and source of all flows affecting their flowgate using information from the IDC.
- An RC experiencing congestion would request an amount of flow reduction that would be processed by the IDC. A relief obligation would be issued to all parties contributing to the loading.
- NAESB will establish a methodology for assigning generation-to-load flows into the appropriate priority bucket.

Subsequently the NERC ORS, at their November 2009 meeting, approved a motion to move forward with the parallel flow visualization project. This motion included the vendor selection and a detailed timeline for the implementation. The solution will include a single common source of the market flow calculation, using an open vetted methodology, which would offer transparency and consistency in the results and a single, common repository of the results to make available identical information to all involved parties. The solution will include a historical archive of results and auditability of those results. The timeline identifies November 1, 2010 as the date when data gathering and the trial period for the parallel flow visualization project will begin. The trial period is expected to last twelve to eighteen months.

### b. <u>Buy-Through of Congestion</u>

The current practice for scheduling of interregional transactions only requires scheduling parties to pay for the congestion charges assessed by the Balancing Authorities that are part of the "contract path" over which an external transaction is scheduled. Costs that an external transaction imposes on Balancing Authorities that are not included in the contract path are not currently considered in the scheduling process, nor are they charged to the scheduling entity. Buy-Through of Congestion addresses this shortcoming by more completely assessing the congestion charges associated with scheduling an interregional transaction to the scheduling entity.

The movement of power from Balancing Authority to Balancing Authority is typically scheduled on a contract path methodology.  In reality, power moves consistent with the laws of physics and the relative impedances of the various elements of the transmission system, and actual power flows can be quite different from the path over which a particular transaction is scheduled to flow.

Managing power that flows in a manner that is not consistent with the path over which transmission service is purchased and the transaction is scheduled (contract path) can be a costly endeavor when the associated uncontrolled off-contract path loop flow causes congestion on prime transmission corridors.  Removing these power flows by implementing the NERC Transmission Loading Relief (TLR) procedures can address the impacts, but employing TLR creates market and operational inefficiencies through the loss of expected energy deliveries without regard to economic rationing principles.  In addition, the existing TLR process does not take into account the scheduling party's possible economic willingness to pay to maintain its transaction schedules or the economic viability of moving power between regions.

More efficient utilization of the transmission network and more accurate transaction scheduling decisions can be achieved if the cost of managing the off-contract path congestion can be calculated and appropriately allocated to the scheduled power transfers that caused the congestion, providing both contract path and off-contract path flows equivalent cost exposure for equivalent use of the transmission network.

Transactions scheduled using firm transmission service are responsible for their congestion impact along the contract path.  The scheduling of transmission service is separate and distinct from the responsibility for paying congestion charges, and is not equivalent to ensuring a congestion cost-free path of transmission access.  Transacting parties, regardless of service provisions, must still supply bids and offer and be evaluated and selected in economic merit order.

In some markets the cost of firm service may include a hedging product to protect against potential congestion charges.  Hedges against congestion costs can also/alternatively be acquired through the available supplemental Financial Transmission Right or Transmission Congestion Contract auctions.  The cost of the available hedging products representing a proxy for the potential congestion cost exposures.  Hedging mechanisms are limited in their scope to the market from which they are procured.  To the extent that service is necessary across multiple regions, multiple products may need to be acquired.

While the costs of parallel flow impacts have not been historically allocated to external transaction schedules,  that outcome was not based upon the expectation that the costs incurred by off-contract path Balancing Authorities were not the responsibility of the scheduling party.   Rather, the problem was that it was not technically feasible to accurately assign parallel flow impacts to a particular transaction.  Congestion costs could not be applied to off-contract path impacts until the evolution of the individual marketplaces achieved the ability to identify and quantify the costs of these impacts and the collective marketplaces achieved a solution that would allow for the application of these charges to the sources. The Parallel Flow Visualization Tool and Buy-Through of Congestion solution will enable the ISOs and RTOs to accurately identify, assign and apply congestion charges to off-contract path flows, thereby comparably charging external transactions for their contract path and off-contract path congestion impacts. All transmission customers will have the opportunity to indicate their willingness (or unwillingness) to be responsible for these congestion charges. Removing a transaction schedule because the scheduling entity has taken an economic position that is no longer viable is a scheduling decision made by the participant. It is not a violation of the firm transmission service arrangement if the customer decides that it is unwilling to pay for redispatch service in off-contract path markets where its transaction has a congestion impact.

The objective of Buy-Through of Congestion is to provide an economics based alternative to administrative curtailment through TLR actions. The main steps in the process are to (a) identify the sources of loop flow caused by Balancing Authority to Balancing Authority schedules via the NERC Interchange Distribution Calculator (IDC) tools, (b) determine the costs incurred in supporting the loop flows via each impacted region as indicated by their locational marginal prices or equivalent, and (c) allocate those costs to the scheduling entity or remove the associated schedules if the scheduling entity is not willing to pay the full cost of completing its transaction(s). The Buy-Through of Congestion processes will result in a more complete identification of and accurate assignment of the costs to move power between regions and provide an economics based alternative to the administrative TLR curtailment processes.

The ability (or point in time) of the subject Balancing Authorities to engage/participate in the Buy-Through of Congestion process will vary. Until such time as the entity is able to place into service the tools and procedures to participate, the entity will continue to utilize the TLR process to remediate the impact of off contract path loop flow induced congestion.

i. Responsible Control Area Duties

The sink Balancing Authority of the inter-control area transaction, or the last control area of the four Lake Erie ISOs to be engaged in the transaction, shall be responsible for administering the Buy-Through of Congestion provisions for that transaction. This entity is referred to in this paper as the “Responsible Control Area.” The Responsible Control Area’s duties include (a) obtaining as part of an entities transaction bid an indication of its willingness to pay (or not to pay) congestion charges caused by the off-contract path impact of that transaction, (b) scheduling or, following a request from the monitoring ISO, removing a transaction in recognition of the transaction’s loop flow impacts, the expected congestion charges associated with the loop flow and the scheduling entity’s indicated willingness to pay those congestion charges, and (c) processing the collection and distribution of settlement charges for the transaction.

Settlement of congestion charges through the Responsible Control Area is necessary as the market participant that is scheduling a transaction may not be a market participant of one or more of the off-contract path control areas that experience additional congestion as a result of the schedule. This process alleviates the need for entities scheduling inter-control area transactions to be participants in every market that could be impacted by the transactions they schedule, although they may still need to become members of the relevant market to participate in the opportunities to hedge these congestion costs..

ii. Monitoring ISO Duties

Each Balancing Authority will be responsible for utilizing the Parallel Flow Visualization tools, currently being developed by the NERC IDCWG, for determining if the congested flowgate is being impacted by parallel flows from transaction schedules. In this situation, the Balancing Authority is acting as the "Monitoring ISO" for the purposes of Buy-Through of Congestion. Subsequent to the identification of parallel flow impacts on the constrained flowgate, the Monitoring ISO will initiate with the respective Responsible Control Area(s) a "request to review" the schedules of these transactions. This request will identify the transactions to be reviewed. Subsequently, the Monitoring ISO will calculate the appropriate congestion charges associated with the remaining transaction schedules that needs to be recovered and will provide that information to the respective Responsible Control Area(s).

iii. Congestion Charge Bidding Indicators

Currently, traders assess the opportunities to transfer power between regions based upon projecting the prices in the regions, transaction costs incurred in arranging the power transfer, hedging opportunities and the risks associated with their predictions. The allocation of congestion costs for transaction impacts incurred by off-contract path regions to the traders who opt to buy-through of congestion will present an additional cost risk that these traders will have to take into account when scheduling transactions.

The ISOs and RTOs will offer enhanced bidding capabilities that will improve the management of this new risk. The bidding enhancement will allow the scheduling party to indicate if they are, or are not, willing to pay the congestion charges caused by their transactions off-contract path flow impacts. If a transacting party indicates it is not willing to pay congestion charges its transaction will be removed by the Responsible Control Area when the off-contract path flows created by the transaction adds to the congestion costs in a Monitoring ISO. Once removed, the transaction will not be reinstated until the neighboring ISO indicates that the congestion on the impacted flowgate has been relieved. Transactions that indicate they not willing to pay congestion charges will not incur such charges for the period of time necessary to remove the transactions after congestion is identified.

Several parties have expressed the need for the Buy-Through of Congestion concept to include the ability to specify a real-time "up-to" congestion charge limitation, indicating the maximum amount of off-contract path congestion the entity scheduling a transaction would be willing to pay. The ISO's acknowledge that the Buy-Through of Congestion concept will result in some of the cost risk exposure being returned from each regions internal load to the transacting parties whose schedules produce the off-contract path congestion. The ISOs are committed to providing the necessary data transparency and visibility of projected and occurring congestion costs to allow traders to consider their cost exposure (See section 4.b.v) when requesting a schedule or alternatively to self-remove their schedules upon observations of congestion charge allocations. The ISO's additionally acknowledge the need to develop the necessary congestion cost hedging products to allow traders to purchase the congestion management product at specified values within the respective Day-Ahead Markets, where applicable. Actual experience has not shown the need for an up-to congestion product to be necessary if there is adequate real-time price transparency around price differences. For these reasons, the ability to additionally specify a real-time "up-to" congestion component will not be available.

iv. Management of Congestion Cost Exposure

Buy-Through of Congestion introduces a new cost allocation mechanism to interchange schedules in the region that must be accounted for when evaluating the viability of a schedule. In addition to opting to not be willing to pay for congestion costs, several products already exist in the various regions markets to provide hedges or costs stops against those charges.

NYISO: Up-to congestion cost available via wheel-through transaction product in DA.
Opportunities to expand virtual trading to the proxy bus locations.

PJM: Up-to congestion product available in DA.
20-minute advance notice schedule termination.
Virtual bidding options available.

MISO: Up-to congestion product available in DA.
20-minute advance notice schedule termination.
Virtual bidding options available.

IESO: No products currently available.[1]

Hedging Opportunities in the MISO Market:

The MISO Energy and Operating Reserve market supports several market products to hedge against unplanned events and volatility that can occur in the real time market.

In the long term planning horizon Auction Revenue Rights (ARRs) are allocated to market participants based on the firm historical usage of the MISO transmission system. The ARRs constitute a hedging mechanism against price uncertainty in the Financial Transmission Rights (FTR) auction. FTRs can be obtained on a monthly or annual basis.

[1] Current there is no day-ahead market nor LBMP within Ontaria

This provides a level of hedging against the congestion charges that a market participant may be exposed to in the Day Ahead market.

In the Day Ahead market, load serving entities and generators can submit fixed or price sensitive bids and offers. These cleared bids and offers provide price certainty against real time market events. In the Day Ahead market, participants may also submit virtual transactions at any CPNode or trading hub. These virtual bids and offers need not be related to a physical resource or load asset. In addition to the above hedging opportunities, a participant can also submit fixed, dispatchable and Up to Congestion schedules. These schedules are cleared and settled based on the Day Ahead market clearing process.

Hedging Opportunities in the NYISO Market:

For the NYISO, the Day Ahead Market currently provides one option for hedging the buy-through of congestion cost. This option is the wheel-through transaction product in the Day Ahead Market which provides the ability for a trader to explicitly hedge the congestion cost between two external proxy buses by providing an 'up-to' offer for the wheel-through transaction.

The NYISO is also considering two additional products for the Day Ahead Market which may provide more hedging flexibility. The two additional products would be (1) to allow Day Ahead virtual trading at the external proxy bus locations and (2) to allow Day Ahead virtual trading based on the price delta of two locations (or virtual spread bid). Virtual Day Ahead trading at the external proxy bus would allow for virtual generation or virtual load transactions at the external proxy buses to be scheduled economically in the Day Ahead Market. The virtual Day Ahead spread bidding option would allow for a virtual position to be taken in the Day Ahead Market based on the LBMP delta of the two locations. The virtual transaction trader would provide an 'up-to' offer indicating the willingness for the transaction to be scheduled based on the price difference between the source location and sink location of the offer.

v. Data Transparency

In order to be able to trade energy effectively, the trader must be able to understand the dynamics of both the revenues and expenses to a trade. Buy-Through of Congestion adds a new element of expense to energy trading by adding a new variable to the trade.

Each Monitoring ISO has the responsibility to provide adequate transparency to any and all buy-through of congestion charges that a trader may incur. To do this, each Monitoring ISO must make available the following information on a nominal five minute basis:

(1) The contract path impacts on all significant flowgates as calculated by the IDC;
(2) The shadow costs on all significant Monitoring ISO flowgates; and

(3) The actual Lake Erie Circulation (LEC) occurring.

The information above is required so that each and every market participant has an understanding of the current exposure to buy-through of congestion. Each Monitoring ISO will use good industry practices to display this information.

Through stakeholder processes, each Monitoring ISO will request market participant feedback to help provide as much transparency as possible to the Buy-Through of Congestion product.

Third Party Tools

In addition to the data provided by each Monitoring ISO, third party services also exist to aide in data visibility and data presentation. These third party tools:

(1) Allow a trader to study future transactions providing an illustration of the impacts (direct and parallel) any contract path trade may have on flowgates;
(2) Allow a trader to assess current contract path impacts (direct and parallel) that exist on flowgates; and
(3) Will allow, in the future, a trader to determine current contract exposure by incorporating current flowgate shadow costs with current impacts.

vi. Transaction Removal Process

The removal of transactions will be accomplished through a coordinated process between a Monitoring ISO and the Responsible Control Area(s). A Monitoring ISO maintains responsibility for ensuring their respective systems are operated to specified reliability standards. Upon detection of a flowgate being constrained in the next hour, a Monitoring ISO will determine if the flowgate is being impacted in a net forward direction by transaction schedules' loop flow impacts, as reported by the Interchange Distribution Calculation (IDC). The IDC will additionally identify each transactions individual impacts on the congested flowgate and the Responsible Control Area for each transaction. The same impact thresholds as are employed in the NERC TLR protocol will apply to the identification of transactions with loop flow impacts on a flowgate.

Loop flow impacts on a flowgate will be influenced by the status and ability of the in-service Phase Angle Regulators to conform actual power flows to scheduled flows. In the absence of PARs, the loop flow impacts are the shift factors of the transaction from source to sink on the flowgate. The loop flow impact across controlling PAR ties will be considered to be zero. For the scenario of a partially controlling PAR, the loop flow impacts will be determine by scaling the normally calculated shift factors by the amount of overflow occurring on the PAR.[2] This calculation will be performed within the IDC.

[2] http://www.nerc.com/docs/oc/idcwg/idcwg-change-orders/CO_nn_partial_phase_shifter.pdf

The Monitoring ISO will notify with the Responsible Control Area(s) to initiate a review of the set of transactions creating loop flow impact on the constrained flowgate. This communication could potentially be automated in the Interchange Distribution Calculator (IDC) whereby it populates a message on the NERC Reliability Coordinator Information System (RCIS) to all reliability coordinators. The Responsible Control Area(s) will review the transaction set and their respective bid indication of willingness to pay for congestion costs. For those that are not willing to pay congestion costs, the Responsible Control Area will remove the transaction schedules and communicate with the Monitoring ISO when those reductions have been completed. At the same time, the Responsible Control Area will update the status of the removed transactions in the IDC.

The NERC TLR procedures will remain as an active viable tool to the system operators to address system overloads. The purpose of the Buy-Through of Congestion solution is to enable recovery of costs associated with managing constraints. By more accurately reflecting the true price of scheduling a transaction, it is expected to reduce the need to utilize the TLR procedures. However, Buy-Through of Congestion is not a mechanism to respond to system overloads under the assumption that increased congestion will cause transaction schedules to be reduced. The TLR procedures will continue to serve this role. TLR procedures take priority and must not be impacted by the existence (or not) of buy-through of congestion provisions. TLR procedures may have to be utilized even if participants are willing to buy-through congestion if the Monitoring ISO is not capable of redispatching for the flowgate that is over its limit. To allow TLR actions to be called in a timely manner in such situations, the "Buy-Through of Congestion process should be initiated as early as possible in the hour ahead.

vii. Transaction Re-instatement Process

Once a market coordination process has been invoked on a flowgate due to congestion, no transaction schedules that would impact the flowgate will be permitted if the entity scheduling the transaction indicates it is not willing to pay congestion costs. Transactions that indicate they are willing to pay for congestion associated with their loop flow impacts will continue to be evaluated in the normal ISO scheduling practices.

A Monitoring ISO will continue to evaluate congestion / constraints on the source flowgate and will notify the Responsible Control Area(s) when the constraint is relieved and the ISO projects that it will be able to manage the flowgate even if the schedules are re-instated. The release of limitations on the flowgate will match the timing of the TLR reload procedures, with notification occurring by the bottom of the hour for next hour scheduling changes.

viii. Forecasted Congestion impact to Scheduling Processes

The Buy-Through of Congestion process is initiated on a comparable basis to the calling of a TLR level 3a. The transmission system is secure; one or more of the Monitoring

ISO's internal transmission flowgates are expected to be at their System Operating Limits (SOL) or Interconnection Reliability Operating Limits (IROL) in the next hour; and the IDC is indicating that there are transactions external to the Monitoring ISO that have a net impact on these flowgates that is at or above the TLR Curtailment Threshold on those facilities. Unlike the TLR process, however, there is no differentiation between transactions using Non-firm Point-to-Point Transmission Service or Firm Point-to-Point Transmission Service.

Once the Buy-Through of Congestion process is initiated, only transactions that indicate they are willing to pay for congestion associated with their loop flow impacts on the identified flowgate(s) will continue to be evaluated in the normal ISO scheduling practices. Transactions that would impact the identified flowgate(s) where the entity scheduling the transaction has indicated it is **not** willing to pay congestion costs, will be rejected. Any consideration of such transaction in future hours will be in accordance with the "Transaction Re-instatement Process" above.

ix. Congestion Cost Determination

Congestion costs will be calculated based upon the LBMP prices, or equivalent, determined either in the region experiencing the flowgate congestion or thru the coordinated Congestion Management activities between regions impacted by the off-control path loop flows. Market participants should be provided a way to evaluate their congestion cost exposure in near-real-time.

With Buy-Through of Congestion, those transactions that wish to opt out of buying through any parallel congestion costs could be removed if congestion is forecasted on the parallel path. The forecasted congestion costs would only be used to determine the need for removing those transactions that did not wish to buy through. When determining congestion charges for those that opted for buying through, the congestion charges would be based on the actual real-time congestion costs that were observed, which may be zero.

Once a market participant indicates a willingness to buy-though the parallel flow congestion charges for a transaction, the market participant shall be subject to charges from the Monitoring ISO.

The non-contract path congestion charges will be calculated using:

(1) The actual real-time shadow cost of the flowgate(s), or comparable LMP differences along the non-contract path;
(2) The transaction's transfer distribution factor[3] on the flowgate; and
(3) The contract path transaction schedule.

The non-contract path congestion charges will be calculated with the information above using the Monitoring ISO's internal billing rules. As an example of one internal billing

[3] http://www.nerc.com/docs/oc/idcwg/training/IDC%20Factors.pdf

rule, some of the Monitoring ISOs calculate a bill using five minute information while other Monitoring ISOs calculate a bill using average hourly information.

All buy-through of congestion charges will be processed by the Monitoring ISOs experiencing congestion on flowgates that can be attributed to energy contracts. The charges will be passed from the Monitoring ISOs that calculate the congestion charges to the Responsible Control Area. The contract will receive notice of the congestion charges as part of the sink control area's invoice.

<u>Example:</u>

A market participant enters into a contract to buy 100 MW of energy from a source located within the Independent Electric System Operator (IESO) and sell the 100 MW of energy to a location within the New York Independent System Operator (NYISO). We will refer to the 100 MW contract as having a contract path from IESO to NYISO.

During the dispatch hour, the following conditions exist for only one five minute interval during an hour:

(1) The Midwest ISO has an actual constrained flowgate in real-time with a shadow cost of $70/MWh;
(2) The 100 MW contract from IESO to NYISO has a 15% transfer distribution factor on the Midwest ISO constrained flowgate; and
(3) The contract path transaction schedule is 100 MW.

For the scenario described above, the calculation becomes $70/MWh * 15% * 100MW * 5/60 h which equals $87.50. The $87.50 would be billed to the contract holder via a bill adjustment to the contract holder's NYISO invoice.

Similarly, if the MISO had calculated a LMP for both the NYISO and IESO, then a comparable calculation could be the transaction contract MWs multiplied by the difference between the MISO LMP for the NYISO minus the MISO LMP for the IESO. With the above calculation, the difference in LMPs would have already captured the contracts transfer distribution factors on the non-contract path.

Please refer to the diagram below which illustrates this example.

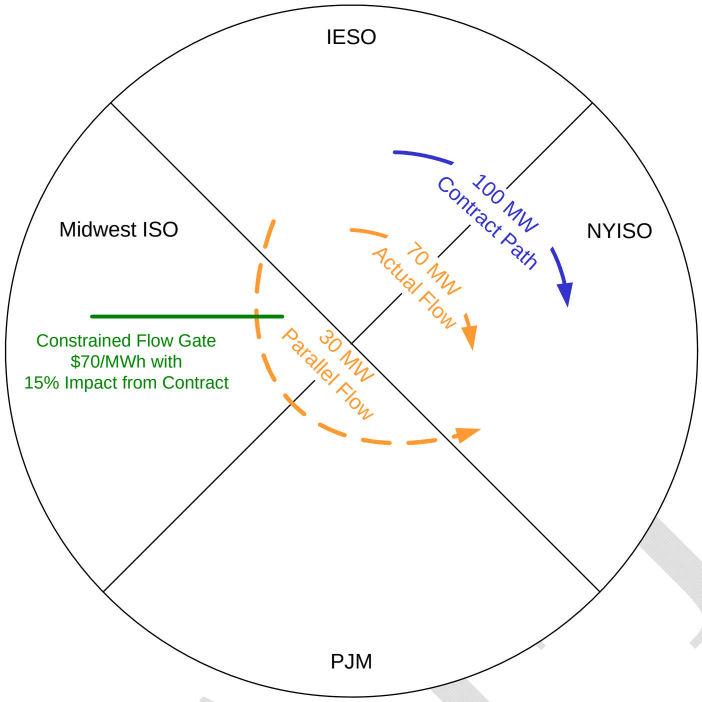



**Figure 1. Congestion Charge Example.**

x. Paying for Congestion Twice

From the congestion charges example, it would seem that the contract owner is double paying for the congestion that was created by the contract. This assertion is false and can best be illustrated with the example below.

Today, the Balancing Authorities security constrained dispatches already capture the impact of parallel (loop) flow when calculating the flowgate overload. The parallel (loop) flows are captured by representing the actual transmission flows within the dispatch.

Depending on the direction of parallel flow, these flows can reduce or increase the congestion on a flowgate. When calculating the flowgate overload (constraint), the calculation nets the forward flows and reverse flows to establish the net flowgate overload (severity of the constraint). The effect of netting the forward and reverse flows on a flowgate is carried through to the calculation of the shadow cost of the constraint. Therefore, when a transaction is not delivered 100% on contract path due to parallel (loop) flows and there is a constraint that separates the contract path from the parallel path (see figure below) the congestion charges for that constraint are reduced by the amount of parallel (loop) flow.

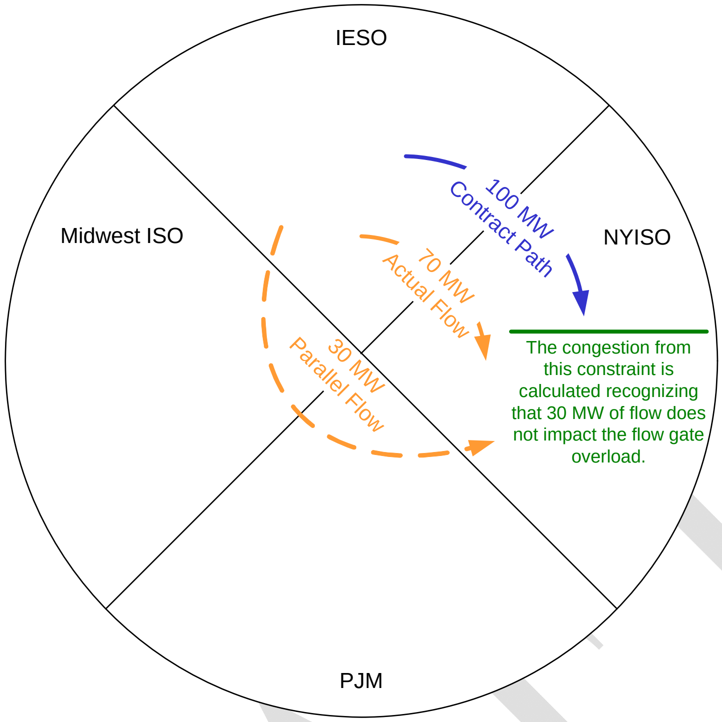



**Figure 2. Paying for Congestion Twice Example.**

<u>Example</u>

A market participant enters into a contract to buy 100 MW of energy from a source located within the Independent Electric System Operator (IESO) and sell the 100 MW of energy to a location within the New York Independent System Operator (NYISO). We will refer to the 100 MW contract as having a contract path from IESO to NYISO.

During the dispatch hour, the following conditions exist for only one five minute interval during an hour:

(1) The amount of parallel flow is 30 MW, while the amount of direct flow is 70 MW; and
(2) NYISO has a constrained flowgate that separates the contract path from the parallel path.

For the scenario described above, the 30 MW of parallel (loop) flow does not impact the constrained flowgate within the NYISO transmission system. This produces a reduced congestion cost (and ultimately reduced LMPs) to solve the constrained flowgate.

<u>Now consider the scenario without the parallel (loop) flow</u>
If the parallel (loop) flow did not exist, then an additional 30 MW of generation would have needed to be dispatched downstream of the constraint in order to prevent an overload. The dispatching of the additional 30 MW of generation downstream of the constraint would have required an equal reduction of generation upstream of the

constraint. This reduction in generation upstream of the constraint would have been represented as a reduction in LMP at the source of the contract.

By reflecting the actual flows when calculating the cost of congestion for the constraint, the calculated LMP at the source of the contract path is generally higher with the presence of parallel (loop) flow than without.

Similarly stated, the LMP at the source of the contract path would have been lower but for the presence of parallel (loop) flow which may have resulted in creating congestion in another Balancing Authorities area.

Conclusion

Therefore, the LMP with no parallel (loop) flow would have resulted in the contract path fully paying for congestion and the LMP with parallel (loop) flow would have resulted in the contract path paying a reduced amount of congestion.

Although congestion in the NYISO was reduced with the existence of parallel (loop) flow, the parallel (loop) flow may have caused or exacerbated congestion in the Midwest ISO or PJM Interconnection. This additional congestion cost is not captured in the congestion already charged to the contract path by the NYISO and currently no mechanism exists for the Midwest ISO or PJM Interconnection to recover the additional cost of congestion caused by parallel (loop) flow.

The Buy-Through of Congestion product creates the mechanism for all of the Balancing Authorities, affected by Lake Erie parallel (loop) flow, to recover this additional congestion cost caused by parallel (loop) flows associated with transaction contracts around Lake Erie.

xi. Settlement of Allocated Costs

The Monitoring ISO will be responsible for determining the congestion cost allocations to assign to the schedules based upon the information contained in the Parallel Flow Visualization tools and its own LBMP, or equivalent, calculations. The IDC will identify the MW impacts associated with transaction schedules. The LBMP calculations will capture the congestion costs incurred in addressing system constraints. Intra-control area generation-to-load impacts will not be included in the assignment of buy-through of congestion costs. Normal flow conditions from generation-to-load impacts are expected under interconnected system operation. Congestion Management protocols will be available to address the impacts created by generation-to-load impacts on flowgates in neighboring control areas.

Once calculated, the Buy-Through of Congestion charges will be processed to the transaction scheduler in a two step process whereby:

(1) The Monitoring ISO provides the charges to the Responsible Control Area(s);
(2) The Responsible Control Area applies the assigned charges to the specific transactions identified by the market flow calculation and collects the revenue from the identified billing organizations through normal billing procedures.

The Responsible Control Area(s) subsequently provides the collected funds to the Monitoring ISO (i.e. off-contract path impacted region.)

All associated buy-through of congestion charges collected by the Responsible Control Area are passed through to the affected off-contract path Monitoring ISOs. No payment to the off-contract path Monitoring ISOs is made in advance of the collection of charges from the scheduling entities, nor is any financial obligation placed on the Responsible Control Area(s) to cover the allocated charges for failures of a transaction party to pay their invoiced charges. Failure of a party to pay for the Buy-Through of Congestion portion of their settlements will be treated as a default with the ISO performing the billing.

All charges associated with buy-through of congestion allocations from the off-contract path region to the Responsible Control Area will be identified in US Dollars.

xii. Payment for Congestion Relief

Off-contract path flows which are having a counterflow impact on (relieving) prevailing flows will result in lower net flows on flowgates and reduced congestion management costs. To the extent that counter-flow off-contract path flows allow for a greater volume of off-contract path forward flow impacts to be managed, then the counter-flow transactions will be compensated at the same rate as the forward flow off-contract path impacts are charged. The total compensation paid to counter-flow transactions will not exceed the revenue received from forward flow impact schedules as calculated by the Monitoring ISO. All compensation payments would be calculated by the Monitoring ISO using the Monitoring ISO's billing rules or philosophies.

After successful implementation of the provisions, the ISOs will monitor the congestion cost charges from, and the congestion relief payment to off-contract path flows. The ISOs will evaluate based upon the successful demonstration of the ability to identify the collection of schedules having forward and counter-flow impacts, as well as the observed revenue sufficiency of congestion management cost recovery, if the limitation on payments for congestion relief can be eliminated.

Alternatively, a trader may explicitly represent those schedules in the relevant market that are expected to benefit from the congestion relief that the transactions will provide. By scheduling a transaction in the appropriate direction, the scheduled transaction will be explicitly settled within that market for the relief provided

### c. **Congestion Management**

A highly interconnected transmission network provides benefits of improved operational reliability and redundancy. However, a necessary byproduct of synchronously interconnected control areas are loop flows resulting from a regions dispatch of its resources to meet its own load requirements. While loop flows can cause or aggravate constraints in a neighboring control area, the synchronous interconnection of neighboring markets also presents the opportunity for multiple control areas to act to relieve transmission congestion on the interconnected system.

The re-dispatch of generators within a control area that is interconnected with the control area that is experiencing the congestion may address transmission constraints more cost effectively than the re-dispatch of generators or other control action within the congested control area. A congestion management protocol allows for inter-control area dispatch to manage congestion (if and to the extent a neighboring control area can re-dispatch resources to alleviate the congestion at a lower cost than the control area that is experiencing the congestion), and permits the appropriate settlement of those actions.

In order to effectively implement congestion management it is necessary to pre-identify constraints that multiple control areas can address through re-dispatch actions, to develop an agreed to baseline of allowable usage of each others transmission networks, and to establish a data sharing protocols to communicate real-time constraint management costs between control areas. After-the-fact calculation of settlement charges will be performed to provide compensation for the dispatch action when the system flows are less than the pre-defined baseline values. Overuse of neighboring control area transmission systems must be redressed at a control areas own cost. Congestion Management will be incorporated directly into a regions dispatch and price setting protocols to maintain the existing consistency between resource schedules and prices. No other explicit charge or refund is necessary to a specific resource.

Congestion Management can achieve a more cost effective utilization of the regions collective assets to address constraints across multiple systems, resulting in lower congestion costs to consumers and provides a more consistent price profile across markets. The Congestion Management details currently being considered and described below are largely based on the existing Market-to-Market coordination program that is currently in place between the Midwest ISO and PJM.

#### i. Flowgate Identification

Flowgates are facilities or groups of facilities that may act as significant constraint points on the system. As such, they are typically used to analyze or monitor the effects of power flows on the bulk transmission grid. Operating Entities utilize flowgates in various capacities to coordinate operations and manage reliability. Flowgates to be included in this congestion management program are determined through a series of studies designed to group flowgates into three categories. The three categories of flowgates are as follows:

1. AFC Flowgates

2. Coordinated Flowgates (CFs)

3. Reciprocal Coordinated Flowgates (RCFs).

An AFC flowgate is any flowgate for which an entity calculates an Available Flowgate Capability value.

A Coordinated Flowgate (CF) is a flowgate impacted by an Operating Entity as determined by one of four studies. Coordinated Flowgates are identified to determine which Flowgates an entity impacts significantly. This set of Flowgates may then be used in the congestion management processes and/or Reciprocal Operations.

A Reciprocal Coordinated Flowgate (RCF) refers to a flowgate that is subject to reciprocal coordination by Operating Entities between one or more Parties and one or more Third Party Operating Entities.

A RCF is:

1. A CF that is (a) (i) within the operational control of Reciprocal Entity or (ii) may be subject to the supervision of Reciprocal Entity as Reliability Coordinator, and (b) affected by the transmission of energy by two or more Parties; or

2. A CF that is (a) affected by the transmission of energy by one or more Parties and one or more Third Party Operating Entities, and (b) expressly made subject to CMP reciprocal coordination procedures under a Reciprocal Coordination Agreement between or among such Parties and Third Party Operating Entities; or

3. A CF that is designated by agreement of both Parties as an RCF.

In order to coordinate congestion management on a proactive basis, Operating Entities may agree to respect each other's flowgate limitations during the determination of AFC/ATC and the calculation of firmness during real-time operations. Entities agreeing to coordinate this future-looking management of Flowgate capacity are Reciprocal Entities. The Flowgates used in that process are Reciprocal Coordinated Flowgates.

Reciprocal Coordinated Flowgates are associated with the implementation of a Reciprocal Coordination Agreement between two Reciprocal Entities. By virtue of having executed such an agreement, a Flowgate Allocation can occur between these two Reciprocal Entities as well as all other Reciprocal Entities that have executed Reciprocal Coordination Agreements with at least one of these two Reciprocal Entities. When considering an implementation between two Reciprocal Entities, it is generally expected that each of the Reciprocal Coordinated Flowgates will meet the following three criteria:

- It will meet the criteria for Coordinated Flowgate status for both the Reciprocal Entities,

- It will be under the functional control of one of the two Reciprocal Entities and

- Both Reciprocal Entities have executed Reciprocal Coordination Agreements either with each other or with a third party Reciprocal Entity.

**Disputed Flowgates**

If a Reciprocal Entity believes that another Reciprocal Entity implementing the congestion management portion of this process has a significant impact on one of their Flowgates, but that Flowgate was not included in the Coordinated Flowgate list, the involved Reciprocal Entities will use the following process.

- If an operating emergency exists involving the candidate Flowgate, the Reciprocal Entities shall treat the facilities as a temporary Coordinated Flowgate prior to the study procedure below. If no operating emergency or imminent danger exists, the study procedure below shall be pursued prior to the candidate Flowgate being designated as a Coordinated Flowgate.

- The Reciprocal Entity conducts studies to determine the conditions under which the other Reciprocal Entity would have a significant impact on the Flowgate in question. The Reciprocal Entity conducting the study then submits these studies to the other Reciprocal Entity implementing this process. The Reciprocal Entity's studies should include each of the four studies described above; in addition to any other studies they believe illustrate the validity of their request. The other Reciprocal Entity will review the studies and determine if they appear to support the request of the Reciprocal Entity conducting the study. If they do, the Flowgate will be added to the list of Coordinated Flowgates.

- If, following evaluation of the supplied studies, any Reciprocal Entity still disputes another Reciprocal Entity's request, the Reciprocal Entity will submit a formal request to the NERC Operations Reliability Subcommittee (ORS) asking for further review of the situation. The NERC ORS will review the studies of both the requesting Reciprocal Entity and the other Reciprocal Entity, and direct the participating Reciprocal Entities to take appropriate action.

**Frequency of Coordinated Flowgate Determination**

The determination of Coordinated Flowgates will be performed at the initial implementation of the CMP and then as requested by another reciprocal entity.

**Dynamic Creation of Coordinated Flowgates**

For temporary Flowgates developed “on the fly,” the IDC will utilize the current IDC methodology for determining NNL contribution until the Market-Based Operating Entity has begun reporting data for the new Flowgate. Interchange transactions into, out of, or across the Market-Based Operating Entity will continue to be E-tagged and available for curtailment in TLR 3, 4, or 5. Market-Based Operating Entities will use reasonable effort to study the Flowgate in a timely manner and begin reporting flowgate data within two business days (where the flowgate has already been designated as an AFC Flowgate). This will ensure that the Market-Based Operating Entity has the time necessary to properly study the Flowgate using the four studies detailed earlier in this document and determine the flowgate’s relationship with the Market-Based Operating Entity’s dispatch. For internal flowgates, the Market-Based Operating Entity will redispatch during a TLR 3 to manage the constraint as necessary until it begins reporting the Firm and Non-Firm Market Flows; during a TLR 5, the IDC will request NNL relief in the same manner as today. Alternatively, for internal and external flowgates, an Operating Entity may utilize an appropriate substitute Coordinated Flowgate that has similar Market Flows and tag impacts as the temporary flowgate. In this case, an Operating Entity would have to realize relief through redispatch and TLR 3. An example of an appropriate substitute would be a Flowgate with a monitored element directly in series with a temporary flowgate’s monitored element and with the same contingent element. If the flowgate meets the necessary criteria, the Market-Based Operating Entity will begin to provide the necessary values to the IDC in the same manner as Market Flow values are provided to the IDC for all other Coordinated Flowgates. If in the event of a system emergency (TLR 3b or higher) and the situation requires a response faster than the process may provide, the Market-Based Operating Entities will coordinate respective actions to provide immediate relief until final review.

ii. Market Flow Calculation

(See description available in section 4.a)

On a periodic basis, the Market-Based Operating Entity will calculate directional Market Flows for all Coordinated Flowgates. These flows will represent the actual flows in each direction at the time of the calculation, and be used in concert with the previously calculated Firm Flow Limits to determine the portion of those flows that should be considered firm and non-firm.

Every fifteen minutes, the Market-Based Operating Entity will be responsible for providing to Reliability Coordinators the following information:

- Firm Market Flows for all Coordinated Flowgates in each direction
- Non-Firm Market Flows for all Coordinated Flowgates in each direction

The Firm Market Flow (Priority 7-FN) will be equivalent to the calculated Market Flow, up to the Firm Flow Limit. In real time, any Market Flow in excess of the Firm Flow Limit will be reported as Non-Firm Market Flow (Priority 6-NN) (note that under reciprocal operations, some of this Non-Firm Market Flow may be quantified as Priority 2-NH).

This information will be provided for both current hour and next hour, and is used in order to communicate to Reliability Coordinators the amount of flows to be considered firm on the various Coordinated Flowgates in each direction. When the Firm Flow Limit forecast is calculated to be greater than Market Flow for current hour or next hour, actual Firm Flow Limit (used in TLR5) will be set equal to Market Flow.

Additionally, every hour the Market-Based Operating Entity will submit to the Reliability Coordinator a set of data describing the marginal units and associated participation factors for generation within the market footprint. The level of detail of the data may vary, as different Operating Entities will have different unique situations to address. However, this data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by the Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

**Day-Ahead Operations Process**

The Market-Based Operating Entities will use a day-ahead operations process to establish the Firm Flow Limit on Coordinated Flowgates. If the Market-Based Operating Entities utilize a day-ahead unit commitment, they will supplement the day-ahead unit commitment with a security constrained economic dispatch tool, which uses a network analysis model that mirrors the real-time model found within their state estimators. As such, the day-ahead unit commitment and its associated Security Constrained Economic Dispatch respects facility limits and forecasted system constraints. Facility limits of Coordinated Flowgates under the functional control of Market-Based Operating Entities and the allocations of all Reciprocal Coordinated Flowgates will be honored.

For Coordinated Flowgates, a Market-Based Operating Entity can only use one of the following two methods to establish Firm Flow Limit. A Market-Based Operating Entity must use either the day-ahead unit commitment and its associated Security Constrained Economic Dispatch, or a Market-Based Operating Entity's GTL and unused Firm Transmission Service impacts, up to the Flowgate Limit, on the Coordinated Flowgate. At any given time, an entity must use only one method for all Coordinated Flowgates and must give ninety days notice to all other Reciprocal Entities, if it decides to switch from one method to the other method. On a case by case basis, with agreement by all Reciprocal Entities the ninety-day notice period may be waived.

**Real-time Operation Process for Operating Entity Capabilities**

Operating Entities' real-time EMS's have very detailed state estimator and security analysis packages that are able to monitor both thermal and voltage contingencies every few minutes. State estimation models will be at least as detailed as the IDC model for all the Coordinated and Reciprocal Coordinated Flowgates. Additionally, Reciprocal Entities will be continually working to ensure the models used in their calculation of Market Flow are kept up to date.

The Market-Based Operating Entities' state estimators and Unit Dispatch Systems (UDS) will utilize these real-time internal flows and generator outputs to calculate both the actual and projected hour ahead flows (i.e., total Market Flows, Non-Firm Market Flows, and Firm Market Flows) on the Coordinated Flowgates. Using real-time modeling, the Market-Based Operating Entity's internal systems will be able to more reliably determine the impact on Flowgates created by dispatch than the NERC IDC. The reason for this difference in accuracy is that the IDC uses static SDX data that is not updated in real-time. In contrast to the SDX data, the Market-Based Operating Entity's calculations of system flows will utilize each unit's actual output, updated at least every 15 minutes on an established schedule.

**Market-Based Operating Entity Real-time Actions**

Market-Based Operating Entities will have the list of Coordinated Flowgates modeled as monitored facilities in its EMS. The Firm Flow Limits a Market-Based Operating Entity will use for these Flowgates will be the Firm Flow Limits determined by the Firm Market Flow calculations.

The Market-Based Operating Entity will upload the real-time and one-hour ahead projected Firm Market Flows (7-FN) and Non-Firm Market Flows (6-NN) on these Flowgates to the IDC every 15 minutes, as requested by the NERC IDCWG and OATI (note that under reciprocal operations, some of this 6-NN may be quantified as Priority 2-NH). Market Flows will be calculated, down to five percent, and uploaded to the IDC. When the real-time actual flow exceeds the Flowgate limit and the Reliability Coordinator, who has responsibility for that Flowgate, has declared a TLR 3a or higher, the Market-Based Operating Entity will redispatch its system to the amount required by the IDC. The amount of redispatch will be calculated by the IDC. In a TLR 3, the Market-Based Operating Entity could be required to redispatch to the full amount of Non-Firm Market Flow over the Firm Flow Limit. Note the Market-Based Operating Entity may provide relief through either: (1) a reduction of flows on the Flowgate in the direction required, or (2) an increase of reverse flows on the Flowgate.

Market-Based Operating Entities will implement this redispatch by binding the Flowgate as a constraint in their Unit Dispatch System (UDS). UDS calculates the most economic solution while simultaneously ensuring that each of the bound constraints is resolved reliably. Additionally, the Market-Based Operating Entity will make any point-to-point transaction curtailments as specified by the NERC IDC.

A Market-Based Operating Entity's redispatch and relief time will be faster than the 30 minutes required by TLR schedule curtailments, because when the bounds are applied, the systems are designed to provide relief within 15 minutes.

The Reliability Coordinator calling the TLR will be able to see the relief provided on the Flowgate as the Market-Based Operating Entity continues to upload its contributions to the real-time flows on this Flowgate.

iii. Entitlements

**Firm Flow Determination**

Firm Market Flows represent the directional sum of flows created by Designated Network Resources serving designated network loads within a particular market area. They are based primarily on the configuration of the system and its associated flow characteristics; utilizing generation and load values as its primary inputs. Therefore, these Firm Market Flows can be determined based on expected usage and the Allocation of Flowgate capacity.

An entity can determine Firm Market Flows on a particular Flowgate using the same process as utilized by the IDC. This process is summarized below:

1. Utilize a reference base case to determine the Generation Shift Factors for all generators in the current Control Areas' respective footprints to a specific swing bus with respect to a specific Flowgate.

2. Utilize the same base case to determine the Load Shift Factors for the Control Area's load to a specific swing bus with respect to that Flowgate.

3. Utilize superposition to calculate the Generation to Load Distribution Factors (GLDF) for the generators with respect to that Flowgate.

4. Multiply the expected output used to serve native load from each generator by the appropriate GLDF to determine that generators flow on the Flowgate.

5. Sum these individual contributions by direction to create the directional Firm Market Flow impact on the Flowgate.

**Determining the Firm Flow Limit**

Given the Firm Market Flow determinations described in the previous section, Market-Based Operating Entities can assume them to be their Firm Flow Limits. These limits define the maximum value of the Market Flows that can be considered as firm in each direction on a particular Flowgate. Prior to real time, a calculation will be done based on updated hourly forecasted loads and topology. The results should be an hourly forecast of directional Firm Market Flows. This is a significant improvement over current IDC processes, which uses a peak load value instead of an hourly load more closely aligned with forecasted data.

**Firm Market Flow Calculation Rules**

The Firm Flow Limits will be calculated based on certain criteria and rules. The calculation will include the effects of firm network service in both forward and reverse directions. The process will be similar to that of the IDC (but utilizing impacts down to five percent). The following points form the basis for the calculation.

1. The generation-to-load calculation will be made on a Control Area basis. The impact of generation-to-load will be determined for Coordinated Flowgates.

2. The Flowgate impact will be determined based on individual generators serving aggregated CA load. Only generators that are Designated Network Resources for the CA load will be included in the calculation.

3. Forward Firm Flow Limits will consider impacts in the additive direction down to 5% and reverse Firm Flow Limits will consider impacts in the counter flow direction down to 5%. Market Flow impacts and allocations using a zero percent threshold are determined for information reporting to the IDC.

4. Designated Network Resources located outside the CA will not be included in the generation-to-load calculation if OASIS reservations exist for these generators.

5. Generators that will be off-line during the calculated period will not be included in the generation-to-load calculation for that period.

6. CA net interchange will be computed by summing all Firm Transmission Service reservations and all Designated Network Resources that are in effect throughout the calculation period. Designated Network Resources are included in CA net interchange to the extent they are located outside the CA and have an OASIS reservation. The net interchange will either be positive (exports exceed imports) or negative (imports exceed exports).

7. If the net interchange is negative, the period load is reduced by the net interchange.

8. If the net interchange is positive, the period load is not adjusted for net interchange.

9. The generation-to-load calculation will be made using generation-to-load distribution factors that represent the topology of the system for the period under consideration.

10. PMAX of the generators should be net generation (excluding the plant auxiliaries) and the CA load should not include plant auxiliaries.

11. The portion of jointly owned units that are treated as schedules will not be included in the generation-to-load calculation if an OASIS reservation exists.

iv. Settlement / Pricing

The Market Settlements under the coordinated congestion management will be performed based on the Real-Time Market Flow contribution on the transmission flowgate from the Non-Monitoring RTO as compared to its flow entitlement.

If the Real-Time Market Flow is greater than the flow entitlement plus the Approved MW adjustment from Day Ahead Coordination, then the Non-Monitoring RTO will pay the Monitoring RTO for congestion relief provided to sustain the higher level of Real-Time market flow. This payment will be calculated based on the following equation:

**Payment = (Real-Time Market Flow MW1 – (Firm Flow Entitlement MW2 + Approved MW3)) * Transmission Constraint Shadow Price in Monitoring RTOs Dispatch Solution**

If the Real-Time Market Flow is less than the flow entitlement plus the Approved MW adjustment from Day Ahead Coordination, then the Monitoring RTO will pay the Non-Monitoring RTO for congestion relief provided at a level below the flow entitlement. This payment will be calculated based on the following equation:

**Payment = ((Firm Flow Entitlement MW2 + Approved MW3) – Real-Time Market FlowMW1) * Transmission Constraint Shadow Price in Non-Monitoring RTOs Dispatch Solution**

For the purpose of settlements calculations, shadow prices will be calculated by the pricing software in the same manner as the LMP, and will be integrated over each hour during which a transmission constraint is being actively coordinated under the ICP by summing the five-minute shadow prices during the active periods within the hour and dividing by 12 (the number of five minute intervals in the hour).

### d. Enhanced Interregional Transaction Coordination

i. Background

Today, the PJM Interconnection and the Midwest ISO provide the ability for market participants to enter into or back out of an energy transaction on a fifteen minute basis on most external interfaces. Additionally, the NYISO and IESO currently allows for hourly energy scheduling across the external interfaces.

For the NYISO, Enhanced Interregional Transaction Coordination will permit the scheduling of inter-control area transactions on a more frequent basis than the current hourly schedules. Flexible transaction scheduling provisions improve market and operational efficiency by allowing resources schedules to adjust to the dynamic changes in system conditions, as well as unexpected changes to projected conditions. Desired additional flexibility must be balanced with the operational benefits associated with defined firm energy delivery schedules.

Flexible transaction scheduling requires advancements to the existing processes for the development of transaction schedules and the protocols for validation of those schedules. The existing process lacks the coordination and automation necessary to support a scheduling frequency sufficient to address dynamic system conditions. Transaction schedules must be co-developed, rather than independently evaluated, to ensure both regions arrive at the same outcome and the same expectations for energy delivery or receipt. A new capability could be developed to schedule transaction based upon moving power between regions at defined price differences, whereby a participant would supply a single transaction request to be used by both regions indicating the transaction should be scheduled when the specified spread between the prices in the two regions is achieved. The regions would use expected prices to select transaction requests with lower bids than the predicted difference in market prices. The regions would incorporate the updated transaction schedules into the dispatch tools and repeat the process for the next scheduling horizon.

Interregional Transaction Scheduling is expected to lower total system operating costs through improved consistency of transaction schedules with market-to-market prices, to expand the pool of flexible assets that are available to balance intermittent power resources, to improve price consistency and transmission utilization and to address existing uncertainties in forward looking scheduling horizons.

ii. Bidding and Scheduling

It is envisioned that all transactions scheduled between Balancing Authorities would still follow all NERC electronic tagging requirements. For those market participants that wish to participate in more frequent scheduling, market participants would model their NERC electronic tag as a dynamic tag.

Hourly transaction or hourly dispatchable transactions are scheduled on an hourly basis by the Day Ahead or Real-Time scheduling systems where the transaction schedules can vary from hour to hour. Intra-hour transactions or intra-hour dispatchable transactions will have an hourly schedule which can vary from hour to hour in the Day Ahead Market, while the Real-Time Market may dispatch the transaction as frequently as every five minutes within an hour. Intra-hour transactions may only be import or export transactions, as wheel-through transactions will not be eligible for intra-hour transaction scheduling.

The bidding systems of the NYISO would continue to require a market participant to enter new hourly transactions into the real-time market at least seventy five minutes prior to the operating hour. Additionally, the NYISO bidding system could be modified to allow intra-hour transactions to be added, updated, or removed closer to the actual dispatch horizon. The purpose of the additional flexibility is to allow market participants to minimize buy-through of congestion exposure.

Depending on the NYISO border, Enhanced Interregional Transaction Coordination may take place on a five or fifteen minute basis. Fifteen minute transaction coordination would be used on borders where the NYISO must coordinate with other markets. Five minute transaction coordination would likely be used on borders where the scheduling interface is fully controllable via Variable Frequency Transformer or Direct Current technology.

To date, the NYISO has already begun developing a concept with Hydro Quebec where intra-hour transactions would be scheduled on a five minute basis. Advisory fifteen minute schedules with Hydro Quebec will be created by Real-Time Commitment ('RTC') and those schedules will be checked out with Hydro Quebec prior to the dispatch hour. During the dispatch hour, the Real-Time Dispatch ('RTD') or Real-Time Dispatch Corrective Action Mode ('RTD-CAM') will generate a five minute interchange with Hydro Quebec. The five minute interchange will be communicated to Hydro Quebec using Inter-Control Center Communications Protocol ('ICCP').

Additionally, the NYISO and PJM have begun working together to develop a concept for fifteen minute transaction scheduling. The NYISO intends to offer the flexibility for market participants to reduce or reinstate a transaction within the dispatch hour. The PJM Interconnection already offers their market participants this flexibility and has a fifteen minute transaction scheduling product in use with other neighbors today.

The NYISO anticipates that the Real-Time Dispatch would economically schedule the intra-hour transactions on a fifteen minute basis. These fifteen minute transaction schedules will be coordinated between PJM and NYISO via a fifteen minute checkout process where automation would be used to facilitate a timely checkout.

Finally, the NYISO intends to phase in this concept starting with each of the PJM-NY controllable tie lines followed closely by the broader NYISO/PJM interface.

iii. Settlement

The NYISO would continue to settle all hourly and intra-hour transaction on a five minute basis. When Enhanced Interregional Transaction Coordination is enabled at a scheduling location, hourly import transaction will no longer be eligible for real-time bid production cost guarantees.

Additionally to deter transaction failures for the sole purpose of increasing real-time LMPs, the NYISO will continue to charge transactions a penalty known as the Financial

Impact Charge (‘FIC’). The FIC is determined by calculating the impact failed transaction had on LMPs using the average RTC LMP as the reference.

### e. <u>Market Modeling</u>

#### i. Interface Proxy Price Determination

Interface proxy bus pricing methodologies utilized across the region need to be carefully understood to ensure the compatibility of the methodologies employed. Efficient and compatible interface proxy bus prices will result in desired and anticipated market response to transfer power among the region. To improve the efficiency of the interface proxy bus pricing results, several developments need to occur to address interface pricing for both the current situation of power control device installations as well as future installations and operations of power control devices.

In recognition of the overall objective of harmonizing the market rules across the region, as well as the current lack of a clear schedule for the implementation and operation of the Ontario – Michigan Phase Angle Regulators to control Lake Erie loop flow, the NYISO will pursue modifications to its interface pricing methodology. As such the NYISO will engage its stakeholder community to adjust the interface price methodologies to:

- Recognize the incremental distribution of power flows around Lake Erie when evaluating and pricing the marginal impacts of transaction and generation schedules;
- Evaluate the need for and scheduling rules surrounding establishing an additional proxy bus location for the MISO to acknowledge power deliveries from or to the Midwest region;
- Evaluate the continued applicability of the existing circuitous path prohibitions.

Additionally, the ISO/RTOs recognize the importance of maintaining compatible and efficient interface proxy bus prices when the PARs on the Ontario – Michigan border are ultimately installed and available for remediation of Lake Erie loop flows. These devices have the ability to redirect the flow of power and adjust the actual power deliveries to be more consistent with contract path, or bid path, intentions. The regions existing interface proxy bus pricing methodologies may not be compatible with all operating scenarios and may need either additional pricing points to be created, interface price weighting associated with current points adjusted or adjustments to incremental distribution of power flows to acknowledge contract path flows to reflect actual operating scenarios. The interface proxy price methodologies will again need to be revised to reflect:

- The state of control of the Phase Angle Regulators to manage Lake Erie loop flows.
    - Under Lake Erie loop flow controlled operation, the actual delivery of power and pricing methodologies will reflect contract path, or bid path, as is currently reflected in the NYISO and IESO implementations.

- Under uncontrolled Lake Erie loop flow operation, the interface proxy price methodologies will need to reflect the revised power deliveries.

- Evaluate the revisions necessary to extend tag-based pricing to incorporate contract path deliveries;
- Evaluate the location(s) established for proxy price determination;
- Evaluate the ability to predict the controllability of the Phase Angle Regulators to manage Lake Erie loop flows to incorporate the necessary assumptions into the respective Day-Ahead markets and Hour-Ahead markets.

ii. Additional NYISO-PJM Interface Pricing Points

At the present time, there are three pricing points between the transmission interface between the New York Independent System Operator (NYISO) and PJM Interconnection (PJM). One interface pricing point is for the larger AC interconnected interface between NYISO and PJM with the other interface pricing points being located at the Neptune DC interconnection between NJ and Long Island, NY and the Linden VFT interconnection between NJ and NYC. Market participants have expressed a desire to see additional pricing points established on the interface between NYISO and PJM.

Traditionally, additional pricing points along a free-flowing AC interface have provided market participants with the ability to game that interface through transaction scheduling activities. This type behavior is difficult for transmission providers to easily identify and curtail scheduled transactions that contribute to loop flows in real-time market operations. NYISO and PJM staffs currently believe that the creation of additional pricing points on the overall AC interface would create opportunities for gaming this interface in a detrimental manner and would result in increased loop flows around Lake Erie.

The deployment of new technologies such as Variable Frequency Transformers (VFTs) may provide the ability to completely control scheduled flows across an additional interface. NYISO and PJM staffs believe it may be possible to establish additional pricing points for these devices if it can be established that the requisite control capability exists to prevent the introduction of additional loop flow impacts. The potential for establishing new pricing points for such facilities will be evaluated by the staffs at NYISO and PJM going forward.

**f. <u>Dispute Resolution</u>**

Parties to this effort will require access to pre-defined dispute resolution protocols to ensure maters of disagreement can be promptly and efficiently addressed. Dispute resolution procedures current exist between PJM and MISO in their Congestion

Management Protocol.  See Article XIV of the PJM and MISO joint operating agreement.[4]

There are also dispute resolution protocols in existing inter-control area operating agreements that could be of use in developing acceptable dispute resolution procedures[5]

These existing agreements will be used as sources to develop a new multi-ISO dispute resolution agreement.  Effective dispute resolution protocols are necessary for the successful implementation of the Buy-Through of Congestion solution.  The new agreement will need to appreciate that FERC jurisdiction only applies to MISO, PJM and NYISO.

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[4] http://www.midwestmarket.org/publish/Document/2b8a32_103ef711180_-76d90a48324a

[5] http://www.nyiso.com/public/documents/regulatory/agreements.jsp