

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.

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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" and "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", "parallel" or "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 flow travels 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.¹ 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 (BRM) initiatives capture the desire to develop a more complete response to loop flows and to 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.

¹ New York Independent System Operator, Inc.'s Exigent Circumstances Filing Requesting Authority to Amend its Tariffs to Preclude the Scheduling of Certain External Transactions, Requesting Prospective Limited Tariff Waivers, Seeking Expedited Commission Action, Requesting Shortened Notice and Comment Periods, and Contingent Request for Consideration Under Section 206 of the Federal Power Act; Docket No. ER08-1281

The NYISO and its neighbors (IESO, Midwest ISO, PJM, ISO-NE and HQ) are working together to remove barriers to a broader regional market that spans Balancing Area (BA) 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 (BTC), (2) Market-to-Market (M2M), and (3) Enhanced Interregional Transaction Coordination (EITC) solutions that are described below. Additionally, IESO and Midwest ISO 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 these 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. BTC responds to off-contract path transaction scheduling congestion management cost recovery, but does not address generation impacts on the network. M2M enables more efficient use of limited transmission resources by providing compensation to generation resources to resolve system constraints. Finally, EITC 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 this 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, are 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. They have the potential to significantly impair market efficiency. BTC 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 contributing to the flowgate congestion.
 - 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 (PFV) and BTC 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.
 - M2M 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.
 - M2M provides for more consistent prices across the borders as the collective assets are utilized to resolve system limitations.
 - EITC 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

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in response to differences in prices between regions and lowers risk in scheduling decisions.

An analysis prepared by Dr. David Patton of Potomac Economics projects annual regional benefits of \$362 million if all the initiatives proposed in this paper are implemented.² The maximum benefit can be achieved through a coordinated implementation of the solutions, and achievement of the objectives, by the IESO, Midwest ISO, NYISO, and PJM. Lesser levels of benefit can be achieved through more limited implementation.

² See the NYISO's October 14, 2010 Supplemental Filing in FERC Docket ER08-1281.

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 placed in service on the interconnection between Ontario and Michigan. Other such “controls are in place and operational on the NYISO-PJM and NYISO-IESO borders. These PARs can be used 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 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.

Other physical solutions that are currently implemented include NYISO’s circuitous path scheduling prohibitions and Available Transfer Capability (ATC)/Available Flowgate Capability (AFC) coordination, which are discussed later in this section. Implementation of BRM solutions may modify or eliminate the need for these procedures in the future.

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 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

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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 is ready to be placed in-service, pending completion of required regulatory approvals. Regulatory approvals are currently expected during the first quarter of 2011. Following start-up testing and operational verification procedures, full operation of the phase angle regulators is anticipated to commence by the end of the first quarter of 2011.

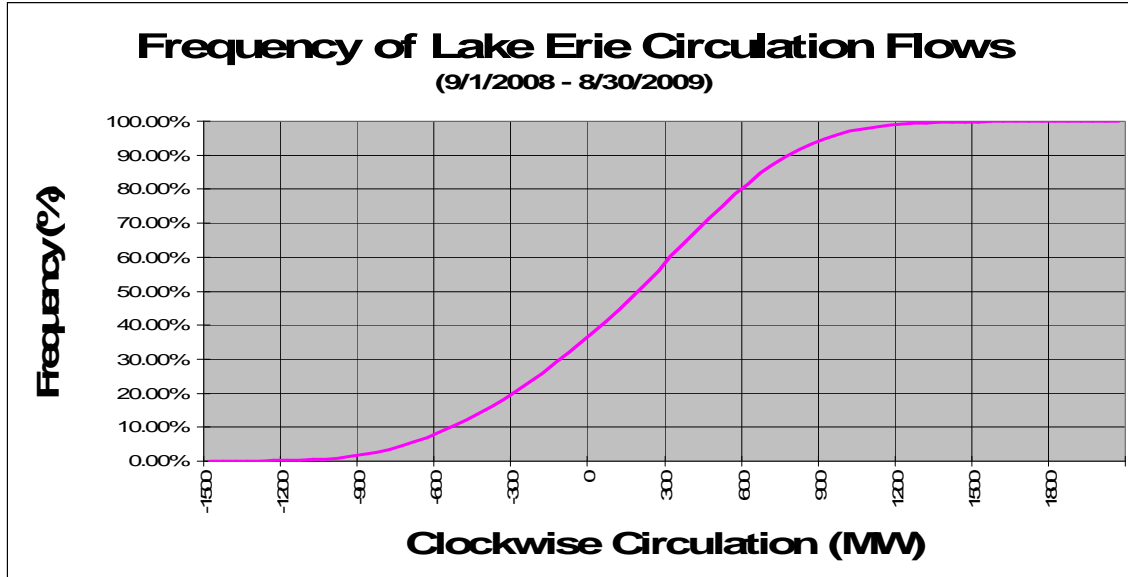
ii. Operating protocol

The operating protocols for the Michigan-Ontario PARs have been developed between ITC, Midwest ISO, 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 LEC. These PARs, with an effective phase angle control range of ± 47 degrees under full load, are expected to be capable of controlling LEC by up to approximately 600 MW in either direction. Control of LEC 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.

Figure 1 Lake Erie Circulation

b. Coordination Operation of Power Control Devices

The operation of 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 alter power flows to follow a different electrical path. There are a number of operating limitations that prevent the use of PARs to eliminate circulation flows. 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 coordinated operation of PARs by the four markets around Lake Erie be considered 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 also be coordinated in this solution 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-Minnesota Power (MP) and IESO-Manitoba Hydro (MH) interface ties. Of the four ties between Michigan Electric Coordinated Systems (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).

The Michigan-Ontario PARs were specifically designed and constructed to provide enhanced control over inadvertent power flow between Michigan and Ontario. The equipment provides for a large number of tap positions, providing for finer granularity of control as well as the ability to adjust the tap positions hourly. Except for the PARs on the IESO-MP interface and the IESO-MH interface, most PARs are not operated to continuously control flows such that schedule flow equals actual flow across an interface. If they were able to control schedule flow equals actual flow, there would be no circulation flow. However, most PARs were installed to address a very specific operational need and are usually successful managing the specific need they were designed and installed to address. 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.

The Ramapo PARs are primarily used to facilitate the delivery of energy over the AC interconnections between PJM and the NYISO as determined by the level of economic interchange schedules of Market Participant External Transactions. The PARs at Waldwick, Linden and Hudson are designed to deliver 1000 MW into the New York City grid via the New Jersey transmission system in accordance with protocols defined in the NYISO Market Services Tariff. The St. Lawrence PARs operate to facilitate interconnected transactions between Ontario and New York, and to make the most efficient use of the of the New York-Ontario interface capacity. These PARs are very effective at meeting their design objective.

When system conditions change such that the design objective is not needed it is difficult to redirect the PARs in a different manner. While the PARs have taps that can reduce the flow bias, there are limits to how many tap movements can be made during the day. There are also dead-bands used such that there is a delay between changes in system conditions and when the PARs recognize the change and move accordingly. The PARs also have a limited number of tap points that restrict the range of their operation. While they can be taken off-line to move a fixed tap to give them more range, this is normally not done for daily cycles when a return to the fix tap position would be needed for other parts of the day. 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 Ramapo 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 Interchange Distribution Calculator (IDC). Under

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this recommendation, 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 LEC needs to be identified so that potential for joint management of these flows during periods when congestion exists can be assessed.

In response to 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 was initiated during 2010 to identify reliability and market impacts of the PARS or other controllable devices having a regional impact on LEC. This ongoing study will also identify significant regional paths or flow gates impacted by LEC.
- Upon completion of the analysis, regional operating guide recommendations may be developed and implemented by the four parties (IESO, MISO, NYISO, and PJM) to reduce Lake Erie loop flow through the coordinated operation of the identified significant controllable devices. This includes implementing the necessary communication infrastructure and regional business processes to facilitate regional coordination of the identified controllable devices.

c. NYISO Circuitous Path Prohibitions

The NYISO tariffs currently contain provisions 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

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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 (RCs), Balancing Authorities (BAs), and Generator Operators (GOs) 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 (DCS) 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 Total Transfer Capability (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 M2M process in place between the Midwest ISO and PJM. The M2M process requires the establishment of Firm Flow Limits on Coordinated Flowgates (CFs). This calculation determines the directional market flow impacts on all CFs 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 RC sets of data describing the marginal units and their associated participation factors for generation within the market footprint. This data is used by the RCs to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

This additional M2M process effectively extends the value of the TTC/ATC/AFC calculation processes by including generation impacts on constrained flowgates which

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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 (PFV)

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 the Parallel Flow Visualization (PFV) project 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 PFV project 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 are visible in the TLR process as an interchange schedule. These impacts would be included in transaction impacts, not generation-to-load impacts.

The NERC IDC Working Group (IDCWG) is currently tasked with defining the necessary data reporting requirements and developing with OATI the specification for performing a generator to load calculation for all entities in the eastern interconnect. Data reporting by the BAs 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 PFV project and the visibility it provides to market flow impacts. The availability of this information is required to support the implementations of M2M and BTC and the management of LEC.

As stated above, a key aspect to the collective ISOs/RTOs commitment to a timely implementation of the market solutions including the collective support for the BTC project implementation was the generator-to-load visibility and curtailment processes which would be provided by the PFV project. This project will result in firm and non-firm generation-to-load flows being reported to the IDC. NYISO intended to leverage the

software developed for the PFV project to report their market flows to the production IDC and avoid incurring infrastructure costs which might otherwise be incurred in order to calculate market flows and assign priorities to those market flows. The other ISO/RTOs supported this direction assuming timely implementation of the parallel visualization project.

NAESB's role in the parallel flow visualization project is to provide a mechanism to assign the priorities of the generation-to-load flows reported to the IDC. Because the currently proposed NAESB interim solution will require that "the assignment of firm and non-firm transmission service priorities for generators within a BA shall follow that Transmission Service Provider's transmission tariff under which that generator operates", the three markets that participate in seams agreements (Midwest ISO, PJM and SPP) are precluded from participating in the interim solution because it does not accommodate generation-to-load priorities that are based on historic flowgate allocations as required in the seams agreements.

The regional markets around Lake Erie agreed in previous FERC filings that they would evaluate the progress of the PFV project and pursue alternative solutions to the generation to load initiative in an effort to maintain the proposed BRM solutions implementation timelines and desired permanent outcomes. This dependency between PFV and the BTC implementation decision will need to be resolved between the markets around Lake Erie prior to moving forward with a regional BTC project.

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. RCs monitor real-time flows using Real Time Contingency Analysis (RTCA) and Supervisory Control and Data Acquisition (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.
- North American Energy Standards Board (NAESB) will establish a methodology for assigning generation-to-load flows into the appropriate priority bucket.

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Subsequently the NERC Operating Reliability Subcommittee (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. A twelve to eighteen month trial period is expected.

b. Buy-Through of Congestion (BTC)

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

Under contract path scheduling, transactions are only assessed charges by BAs that are part of the contract path. BAs outside the contract path may experience congestion, and the resulting re-dispatch costs, from parallel flows caused by these transactions. Currently, the only solution available to alleviate parallel flows is the NERC TLR procedure. BTC will provide another tool for BAs to manage congestion resulting from parallel flows in addition to allowing scheduling entities more control over transaction scheduling and potential subsequent curtailment.

Rather than curtailment of a transaction through TLR procedures, with its resultant operational and market impacts, BTC will address the actual costs resulting from congestion caused by parallel flows. The impact and cost of congestion will be transferred to the party scheduling a transaction. This cost will then become a factor in the scheduling party's decision making process. Scheduling becomes a market based decision that reflects the costs of reliable operation, resulting in a more efficient use of the transmission system.

Although BTC could be accomplished unilaterally by a single ISO, coordination of the participating ISOs will be required to fully implement and realize the benefits of BTC.

i. Overview

The BTC Request for Interchange (RFI) process will not replace the existing NERC e-Tag RFI process, rather it will allow the scheduling entity to indicate if it is, or is not, willing to pay the congestion charges caused by its transaction's parallel flow impacts. Initially, the BTC procedure will apply only to transactions classified by NERC as "Non-Firm" (NERC Priorities 0-6) on the congested flowgate. NERC Priority 7 transactions will not be subject to BTC provisions, and will remain at highest priority in the event of TLR initiated curtailments.

If a scheduling entity indicates it is willing to pay congestion charges (Willing to Buy-Through or “WBT”) its transaction will receive priority over other Non-Firm transactions in the TLR curtailment process. Entities scheduling non-firm transactions that are not willing to pay for congestion (Not Willing to Buy-through or “NBT”) will have their transactions curtailed while non-firm WBT transactions are permitted to continue. WBT transactions will not incur congestion charges for the period of time where the RC manages congestion without invoking the TLR procedures.

The objectives of the BTC proposal to the BRM initiative are:

- (a) allow scheduling entities the option to elect to BTC in exchange for reduced exposure to TLR curtailment;
- (b) determine the costs incurred in supporting the loop flows by each impacted region, as indicated by the actual real-time shadow cost of the relevant constrained flowgate(s), or the equivalent;
- (c) allocate the costs incurred by the off-contract path BAs to the scheduling entity, or remove the associated transaction schedules if the scheduling entity is not willing to pay the total cost of flowing its transaction(s); and
- (d) provide near real-time pricing information to the scheduling entities to allow them to make self-curtailment decisions based on congestion charges.

The BTC processes will result in a more complete identification and accurate assignment of the costs incurred transferring power between regions and will provide a market based enhancement to the administrative TLR curtailment processes.

ii. Monitoring ISO Duties

A Monitoring ISO is the BA responsible for determining if a monitored congested flowgate is being impacted by parallel flows resulting from external transaction schedules. The Monitoring ISO will initiate a TLR event to identify transactions to provide the necessary relief. If a transacting party indicates it is NBT their Non-Firm transaction(s) will be removed via the TLR process prior to any Non-Firm WBT transactions. Once removed, the transaction will not be reinstated until the Monitoring ISO indicates that the congestion on the impacted flowgate has been relieved, and any curtailed Firm transactions have been restored.

iii. Registration and Bidding

A Financial Responsible Party (FRP) will register with each BA in which it desires to participate in the BTC option. Each ISO/RTO will use their local registration practices when registering a FRP that desires to participate in the BTC option. The FRP need not

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register in all ISO/RTOs participating in BTC, but may select one or more ISO/RTOs for participation.

As an example, if a FRP is expecting to trade between IESO and NYISO, then the Market Participant may wish to register to use the BTC option with Midwest ISO, PJM or both.

Each ISO/RTO currently has a corporate credit policy in place. These policies may need to be modified in order to accommodate BTC. In order to qualify as a BTC customer with an individual ISO/RTO, an MP must meet and comply with that ISO/RTO’s credit requirements.

Figure 2 summarizes both the registration and bidding process flows.

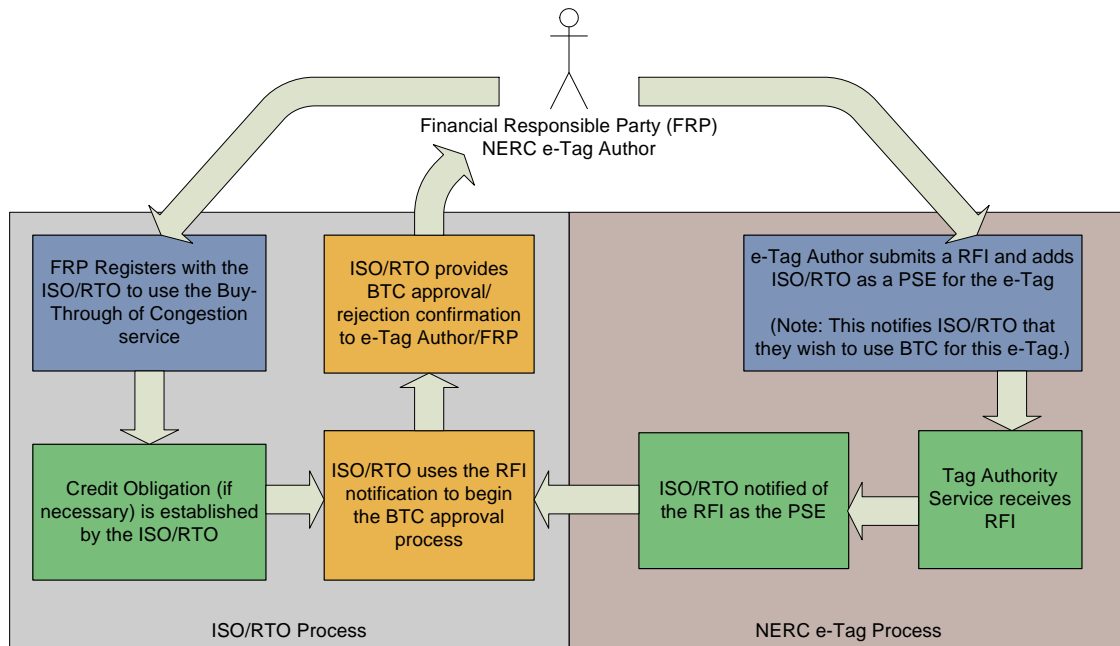


Figure 2 BTC Registration and RFI Process Diagram

iv. Transaction RFI Process with BTC: Opting for BTC

The NERC electronic-Tagging (“e-Tag”) process will not need to be modified to facilitate the BTC process. An FRP would indicate on each NERC e-Tag the willingness to buy-through congestion by separately naming each off-contract path BA the FRP wishes to “buy-through”. An off-contract path BA is a BA that is not named as a TP on the NERC e-Tag. Each off-contract path BA that is added to the NERC e-Tag indicates that the FRP (which should be the NERC e-Tag author) is requesting to “buy-through” that BA’s congestion.

When an off-contract path BA is missing from a NERC e-Tag, the FRP is opting not to “buy-through” that BA’s congestion and therefore is available for curtailment by that BA prior to those NERC e-Tags that are requesting to “buy-through” that BA’s congestion.

1. Current NERC e-Tag Information

Today, the NERC e-Tag defines the Generation Control Area (“GCA”), Load Control Area (“LCA”), Purchasing/Selling Entity (“PSE”) and Tag Code. The Tag Code is the unique identifier of the NERC e-Tag.

Tag Information			
GCA	PSE	Tag Code	LCA
ONT	EMAEC	NNND009	NYIS

Figure 3 NERC e-Tag Information Example

There may be more than one PSE on a NERC e-Tag; all of the PSEs are notified of the e-Tag.

Market Path			
PSE	Product	Contract	Misc
EMAEC	G-F		No
NLHECC			No
EMRA1	L	8530732	No

Figure 4 NERC e-Tag Market Path Example

Physical Path							
CA	TP	PSE	POR	POD	Sched Entities	Contract	Misc
ONT		EMAEC	Source: ONT				No
	ONT	EMAEC	ONT	ONT.EXPORT.AT	ONT, HQT		No
	HQT	NLHECC	ON	HQT	HQT		No
	HQT	NLHECC	HQT	MASS	HQT		No
	NYIS	EMRA1	NYIS	NYIS	NYIS		No
NYIS		EMRA1	Sink: NYIS			8530732	No

Figure 5 NERC e-Tag Physical Path Example

2. Buy-Through Entity Interaction

Once an FRP submits a RFI with one or more ISOs named as a PSE on a NERC e-Tag, the named ISO would receive a message from the Tag Approval Service that an e-Tag exists that requires the BA's attention.

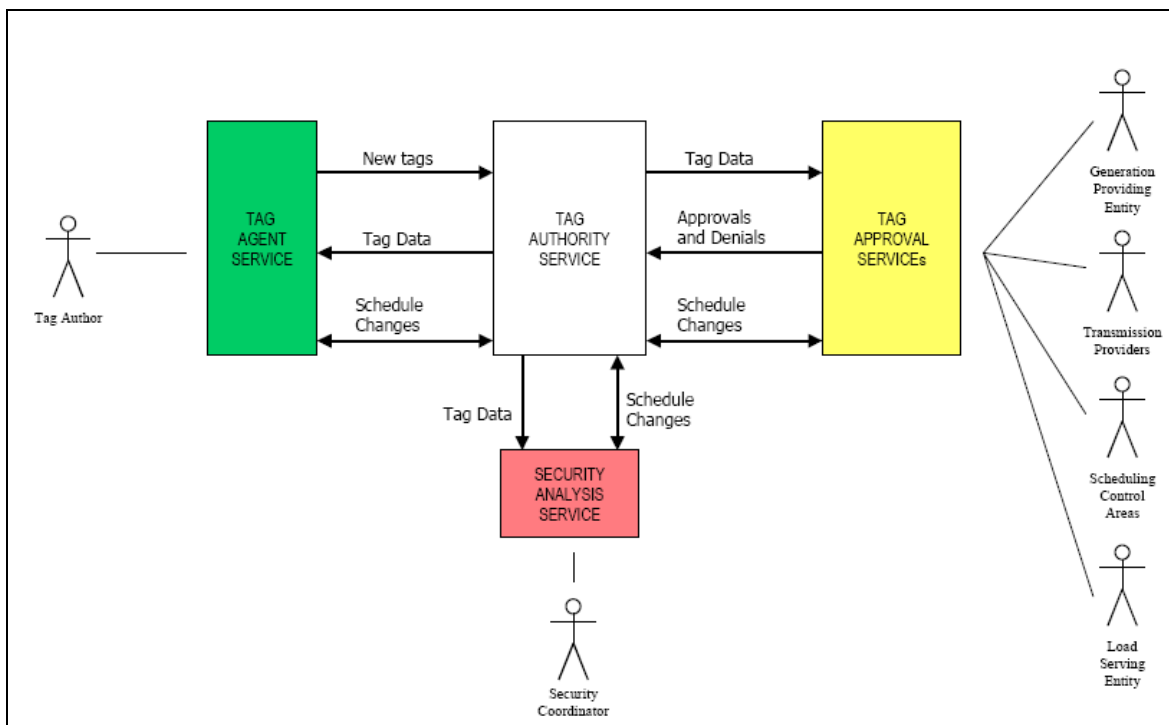


Figure 6 Current NERC e-Tag Process

The process determines if the e-Tag author is a registered FRP within a specific BA and that BA has the ability to respond to BTC requests. Credit qualification by the BAs included on the e-Tag shall be part of the verification process.

If the FRP has sufficient collateral, then the process would notify the e-Tag author indicating that the NERC e-Tag has been approved for BTC service. The BA may choose to delay this decision for NERC e-Tags submitted far in advance of the hour, in order to ensure that other trading opportunities are not prevented while collateral is held for an early submitted NERC e-Tag.

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Finally, notification to the e-Tag author of its BTC status with all affected BAs would occur.

All BA approvals and denial timings for BTC service should align with the current NERC e-Tag timeline for the Eastern Interconnection.

3. BTC Entity Default Status

Each BA shall define the default approval status that would be used in the event that the BA does not respond to the e-Tag BTC request in the timeframe necessary to appropriately coordinate BTC requests and TLR events.

Response failures can occur when the e-Tag service has a “COMM FAIL” or when the BA itself is having technical problems with the e-Tag service.

v. BTC Alignment with Interchange and TLRs

1. Timing of RFIs

The timing of RFIs is summarized in the following figures. For the purposes of this paper, we will consider that all RFIs are submitted on time.

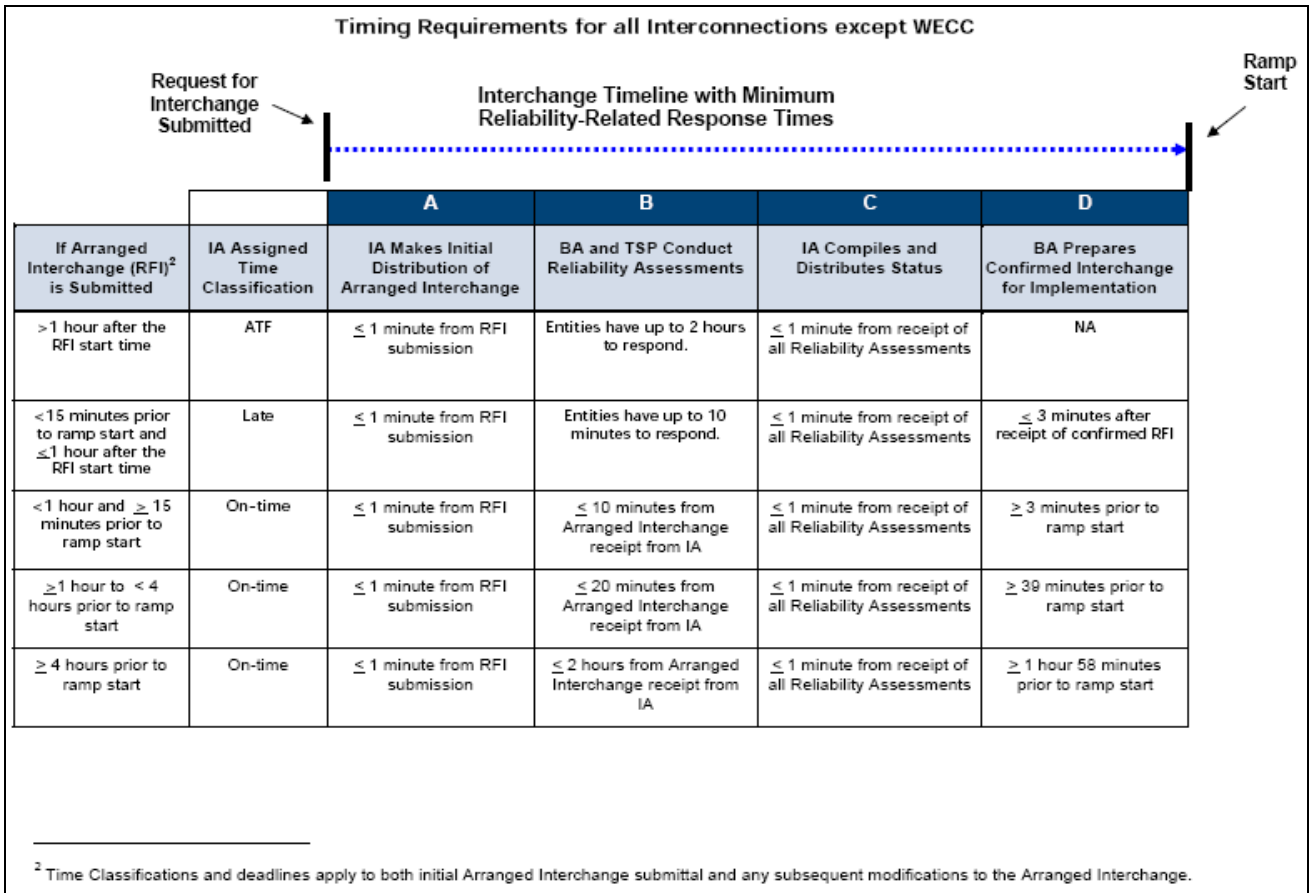


Figure 7 Arranged Interchange Timings

Example of Timing Requirements for all Interconnections except WECC

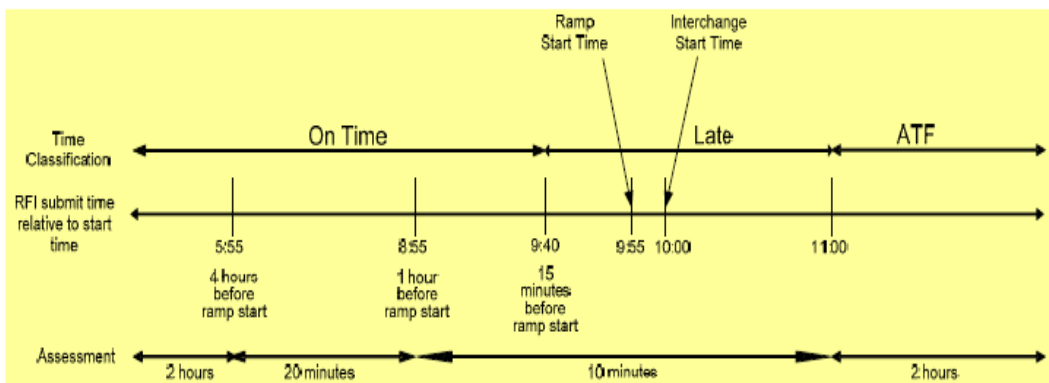


Figure 8 RFI Timing Requirements Timeline

During TLR events when the Reallocation deadlines are in effect, the e-Tags of Non-Firm Willing to Buy-Through (WBT) transactions must be submitted to the IDC by 00:15

of the prior hour to be considered. This is in accordance with current NERC e-Tagging deadlines..³

2. Interaction and Priorities of BTC Transactions within the TLR Process

For the purposes of administering the BTC product, NERC e-Tags will continue to be managed as specified by NERC and NAESB. Each BA that participates in BTC will submit to the IDC on an hourly basis the list of e-Tags that have been approved for BTC service. This information will be used by the IDC to modify the sorting of e-Tags during TLR relief requests, prioritizing BTC transactions as defined in this document. This information is required by the IDC no later than 35 minutes prior to the hour.

Links to additional information are:

- Definition of TLR levels: <http://www.nerc.com/files/IRO-006-4.1.pdf#page=12>
- IDC Reallocation Process and Timing: <http://www.nerc.com/files/IRO-006-4.1.pdf#page=19>
- TLR Examples: <http://www.nerc.com/files/IRO-006-4.1.pdf#page=31>

a. Transaction Curtailment Process

The process flow diagram below illustrates the curtailment of BTC transactions integrated into the current TLR process. Note that under BTC, WBT Non-Firm transactions are curtailed after all NBT Non-Firm transactions are curtailed. WBT transactions will remain flowing as long as re-dispatch is a feasible option for the Monitoring ISO.

³ All tag updates are required no later than 35 minutes prior to the hour to ensure the reallocation process has sufficient time to update for bottom of the hour TLR events.

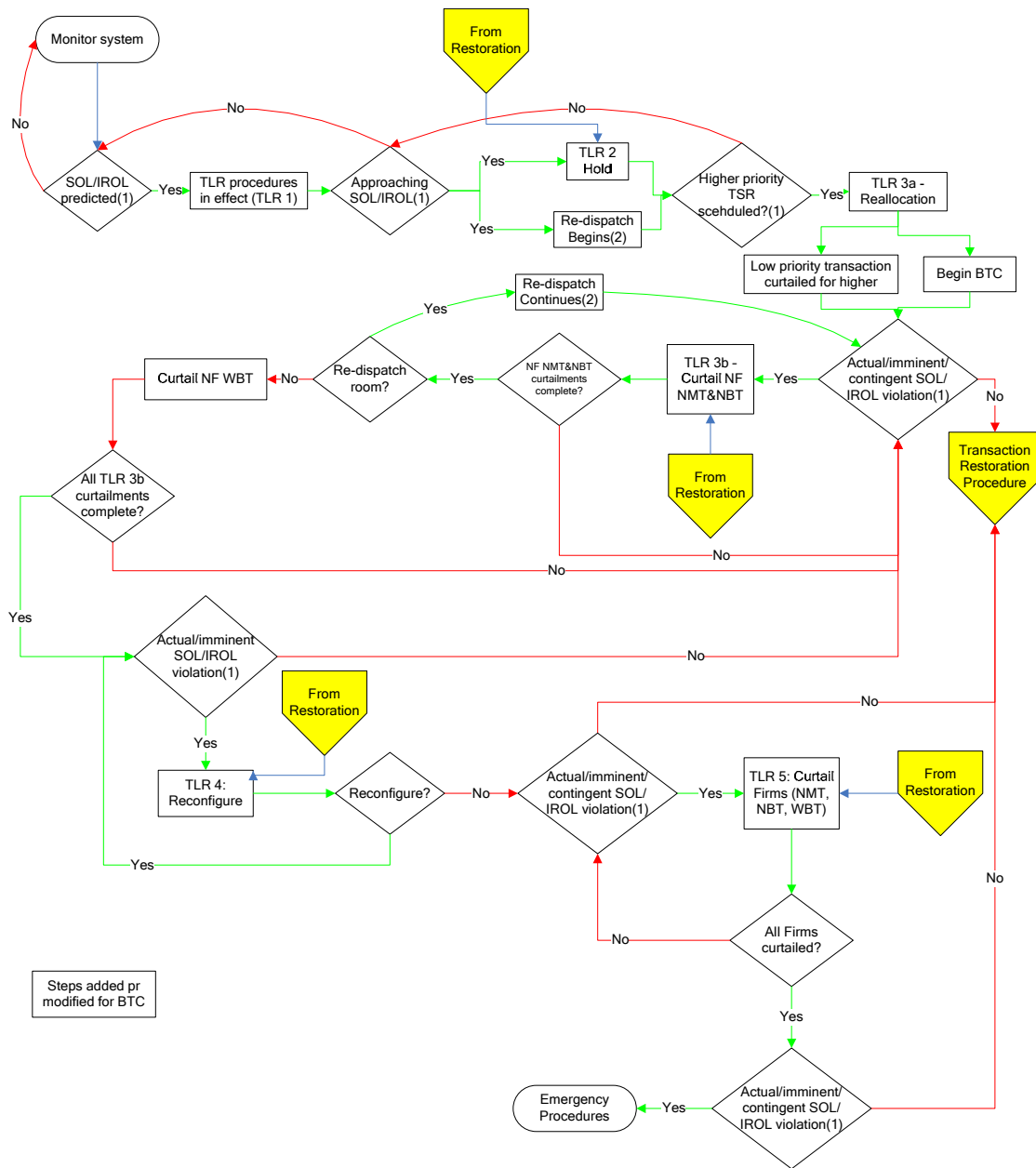


Figure 9 Transaction Curtailment Process

The BTC process is initiated with 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.

Once the BTC process is initiated, only transactions that are designated as WTB or as NERC Priority 7 will continue to be evaluated in the normal ISO scheduling practices. Transactions that would impact the identified flowgate(s) where the entity scheduling the Non-Firm 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” below.

b. Transaction Re-instatement Process

As conditions return to normal, transactions are restored with WBT transactions receiving priority over NBT non-firm transactions, as shown in the process flow diagram below.

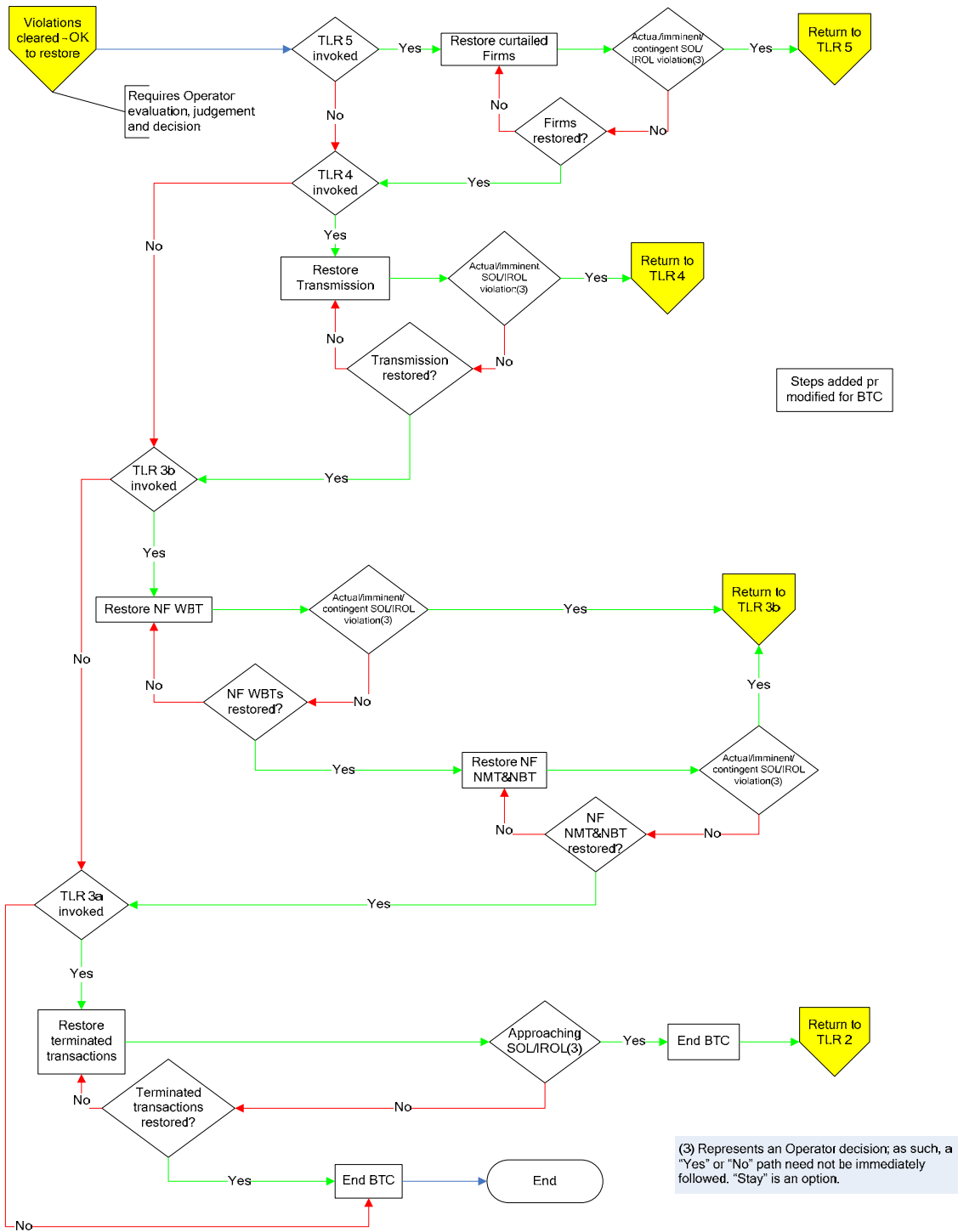


Figure 10 Transaction Re-instatement

vi. Hedging Products for Managing Congestion Cost Exposure

BTC introduces new transaction costs that must be accounted for by MPs when considering the feasibility of scheduling a transaction. In addition to simply opting to not be willing to pay for congestion costs, several products already exist in the various region's markets to provide hedges or costs stops against those charges:

- NYISO: Up-to congestion cost hedge available via wheel-through transaction product in DA.
Opportunities to expand virtual trading to the proxy bus locations.
Opportunities for real-time congestion hedges
- PJM: Up-to congestion product available in DA.
20-minute advance notice schedule termination.
Virtual bidding options available.
- Midwest ISO: Up-to congestion product available in DA.
30-minute advance notice schedule termination.
Virtual bidding options available.
- IESO: No products currently available.

1. Hedging Opportunities in the Midwest ISO Market:

The Midwest ISO 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 Day Ahead market, participants may submit virtual transactions at any CPNode including the external proxy bus locations. These virtual bids and offers are scheduled economically in the Day Ahead Market and need not be related to a physical resource or load asset. In addition, a participant can submit Fixed, Dispatchable and Up-to-TUC (practically equivalent to Up-to Congestion) interchange schedules. Up-to-TUC Interchange Schedules are physical transactions created via NERC E-Tag that specify a willingness to pay the Transmission Usage Charge (TUC) (in \$/MWh) represented by a maximum amount beyond which the MP agrees to be curtailed. MPs can specify any amount of TUC they are willing to pay "up to" \$25/MWh. These schedules are cleared and settled based on the Day Ahead market clearing process.

While these Day Ahead market provisions allow hedging against the BTC charges incurred in real time, MPs can choose to hedge against the volatility of congestion charge exposures in the Day Ahead market by obtaining Financial Transmission Rights (FTR) in the annual or monthly FTR auction. In addition, Auction Revenue Rights (ARRs) are allocated to market participants based on the firm historical usage of the Midwest ISO

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transmission system. The ARRAs constitute a hedging mechanism against price uncertainty in the FTR auction.

2. Hedging Opportunities in the NYISO Market:

For the NYISO, the Day-Ahead Market currently provides the option to schedule wheel-through transactions that would provide a hedge for BTC costs. This product provides the ability for a trader to explicitly hedge the congestion cost between two external proxies. In the Day-Ahead Market, the trader can provide an “up-to” offer defining the congestion costs they are willing to pay to have the transaction scheduled. The scheduling option would allow a position to be taken in the Day-Ahead Market based upon the congestion cost difference between the source and sink locations of the offer, as long as that cost difference was less than the offered maximum amount. The subsequent real-time application of BTC charges would be offset by the balancing obligation (payment) on the Day-Ahead Market position, thereby providing a hedge against those costs.

The NYISO is also considering two additional products for the Day Ahead Market which would provide additional options for hedging BTC charges. 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 any two locations (or congestion spread). 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 offered or bid and economically evaluated in the Day Ahead Market. The virtual Day Ahead congestion bidding option would allow for a virtual position to be offered or bid and economically evaluated in the Day Ahead Market based on the LBMP difference between any two locations. The virtual transaction trader would provide an ‘up-to’ offer indicating the amount of congestion charges they were willing to incur to be scheduled based on the congestion component price difference between the source and sink locations of the offer.

The availability of Transmission Congestion Contracts (TCCs) would provide further congestion cost protection by allowing a trader to pre-purchase the rights to the congestion costs on a desired transmission service path. With a TCC, a trader is hedged, or protected, against the costs of procuring that necessary transmission service in the NYISO’s Day-Ahead Market.

3. Hedging Opportunities in the PJM Market:

PJM intends to leverage existing market mechanisms for hedging of congestion charges associated with BTC, financial hedging mechanisms include an “up-to” congestion product virtual bids in the Day Ahead Market.

The “up-to” congestion transactions work such that the energy trader submits an offer price and MW quantity in addition to a source and sink location for a transaction into the Day Ahead Market. The submitted transaction will clear if the difference in the

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congestion component of the LMPs (sink – source) is less than the offer price submitted with the transaction. This guarantees that the transaction will not clear if the associated cost of congestion from the transaction is greater than the willingness to pay. The clearing process for the “up-to” congestion transaction will be augmented such that the clearing mechanism incorporates both the congestion from the direct source and sink for the transaction plus any congestion caused by parallel flows that the transaction imposes. Once a transaction has cleared in the Day Ahead Market, it is obviated of any additional real-time PJM congestion charges for up to the Day Ahead scheduled quantity in the hour such transaction was cleared.

Virtual bids may also be submitted by market participants in the Day Ahead Market. These financial tools allow traders to take Day Ahead positions at specific locations that can then be used hedge RT congestion costs resulting from BTC. Specifically for hedging BTC costs market participants can take Day Ahead positions using increment or decrement offers at interface pricing points.

vii. Data Transparency

Traders require a full knowledge of costs associated with a transaction in order to adequately access risk and return. BTC will be an additional cost to be considered when evaluating a potential transaction.

Each Monitoring ISO will be required to provide adequate transparency to any and all BTC charges that a trader may incur. The following information shall be available, through the ISOs’ EMS or the IDS:

- (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.

Historical data can be used by traders to evaluate potential risk and return on proposed transactions. With this real-time and historical data, market participants will be able to evaluate potential exposure to BTC.

viii. Congestion Cost Determination

Two methods are currently under evaluation to determine proper congestion costs to apply to WBT transactions. Costs can be determined using calculated prices at the borders of the Monitoring ISO, or the actual shadow cost at the congested flowgate. See Section 4.b.x.3 for a further discussion on the use of LMP vs. shadow costs. When determining congestion charges for WTB transactions, the congestion charges would be based on the actual real-time congestion costs that were observed, which may be zero. Market participants will be provided a way to evaluate their congestion cost exposure in near-real-time.

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The inputs to the determination of congestion cost to apply to a WBT transaction are:

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

For final settlement, the Monitoring ISO's settlement rules shall apply, as per the applicable Tariff. MPs will be billed directly by the Monitoring ISO.

Example:

A market participant enters into a contract to buy 100 MW of energy from a source located within the IESO and sell the 100 MW of energy to a location within the 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 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) Although 30 MW of the 100 MW contract from IESO to NYISO flows through Midwest ISO, it only has a 15% transfer distribution factor (resulting in a 15 MW impact) on the Midwest ISO constrained flowgate; and
- (3) The contract path transaction schedule is 100 MW.

For the scenario described above, the calculation becomes $\$70/\text{MWh} * 15\% * 100\text{MW} * 5/60$ hour which equals \$87.50. The \$87.50 would be billed directly to the PSE by the Midwest ISO.

Similarly, if the Midwest ISO had calculated a LMP for both the NYISO and IESO, then a comparable calculation would be the transaction contract MWs multiplied by the difference between the Midwest ISO LMP for the NYISO minus the MISO LMP for the IESO. With the above calculation, the difference in LMPs would have already captured the contract's transfer distribution factors on the non-contract path and produced a price difference between the two locations of \$10.50. The same amount would be billed to the PSE by the Midwest ISO ($\$10.50/\text{MWh} * 100 \text{ MW} * 5/60$ hour = \$87.50).

Please refer to the diagram below which illustrates this example.

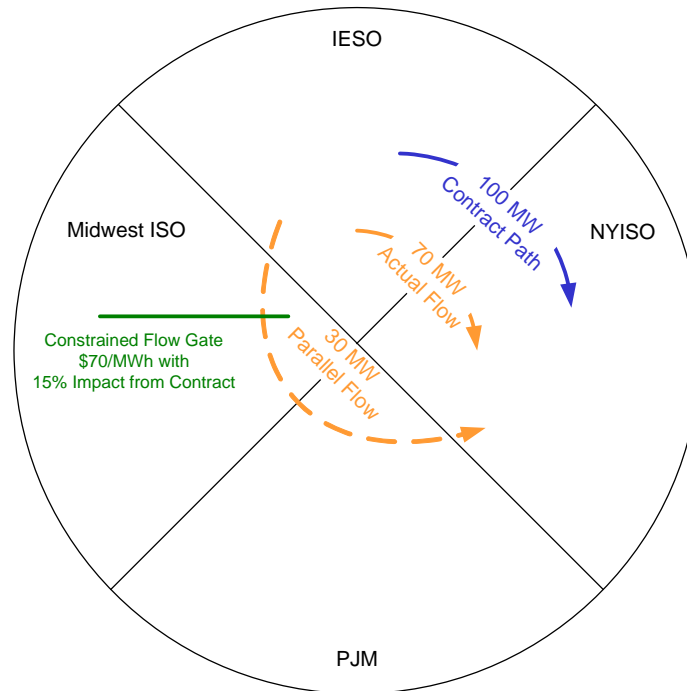


Figure 11 Congestion Charge Example

In this example, there may be a concern that the transaction is not only charged for congestion across the Midwest ISO flowgate, but also for congestion on the full contract amount (100 MW) by the NYISO. The price calculated at the sink in NYISO reflects only the 70 MW of actual flow from IESO into NYISO. The cost of the 30 MW flowing through the Midwest ISO is reflected in the shadow cost on the 15 MW at the constrained Midwest ISO flowgate. The 30 MW of parallel flow is charged for congestion only once, by Midwest ISO.

ix. Settlement of Allocated Costs

1. Overview

This section outlines a proposed set of settlement rules for calculating off-contract path congestion costs and credits. These costs and credits, and their assignment to the responsible market participants, are determined utilizing data from three sources: the Monitoring ISO’s own market calculations, the IDC, and NERC’s Transaction Information System (TIS). Actions that are required of the Monitoring ISO in order to ensure the veracity/ validity of the IDC and/or TIS data sets (e.g. validation of BTC flag) are separately identified in the other sections of this paper.

The off-contract path flows through a congested flowgate caused by external transactions may be in either the forward (i.e. contributing to congestion) or counter-flow (i.e.

relieving congestion) directions. These counteracting flows are illustrated in the figure below for non-firm transactions that have indicated that they are either WBT or NBT.

Figure 12 Potential Sources of Flowgate Impacts

Only the non-firm WBT transactions are subject to BTC charges or eligible for BTC credits. NBT transactions in the forward direction can be removed/curtailed by the activation of the TLR process in accordance with the BTC/TLR protocol. NBT transactions which yield counter-flow loop flows across the flowgate do not qualify for BTC credits.

2. General Rules

The detailed settlement equations below are based on the following general rules, requirements and assumptions:

- i) Individual market participants register with the ISO through whose market footprint they wished to secure BTC services;
- ii) Credit exposure requirements are as defined by each individual ISO's processes;
- iii) Transactions are identified by their NERC e-Tag identifier;
- iv) Market participants settle their BTC charges directly with the ISO that initiates a buy-through of congestion event and incurs associated congestion costs (and possibly simultaneous congestion relief);
- v) There is no BTC settlement required with respect to non-firm transactions which have indicated that they are not-willing to buy through congestion. These transactions, however, may be removed/curtailed by the TLR process in accordance with the BTC/TLR protocol;
- vi) All non-firm transactions which have not indicated their willingness to pay congestion will be defaulted to NBT;
- vii) There is no BTC settlement required with respect to any transactions which have less than a 5% impact (i.e. their TDF is less than 5%) on the element or flowgate for which a BTC event is initiated;
- viii) Flowgates may be actively managed by multiple ISO's via M2M. BTC charges, however, are only collected by the Monitoring ISO. The same holds true for BTC credits;
- ix) BTC charges/credits are applied simultaneous with the initiation of active management of a constraint (i.e. once a TLR level 3a or higher is called). This may occur immediately (within the hour) or at the top of the next hour, consistent with the corresponding TLR response timeline;
- x) BTC charges/credits cease at end of the termination BTC event;

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- xi) BTC charges/credits are determined using the constraint shadow costs at the flowgate. This serves to avoid overlap with potential market-to-market charges;
- xii) BTC charges pertain only to the congestion costs across the impacted flowgate. The Monitoring ISO does not assign any other cost allocations to the transaction;
- xiii) Although not an issue for US ISOs, the BTC charges may attract the application of harmonized sales tax (HST) in Ontario;
- xiv) Billing and invoicing cycle is as per each individual ISO's current processes;
- xv) Settlement is effected by each ISO in currency of the ISO's own market;
- xvi) The invoice quantity dispute process and procedures are as defined by each individual ISO's processes; and
- xvii) Collection default process and procedures as defined by individual ISO's processes.

Other considerations in the determination and settlement of BTC charges include:

Timeliness of eTag Information - Profile Changes must not affect points in time more than one (1) hour in the past with the exception of DYNAMIC e-Tags which must not affect points in time more than 168 hours in the past. Capacity transactions can be activated, i.e. converted to energy, with zero ramp durations upon a contingency.

Timing & alignment of Input data – The data necessary for calculating settlement charges will come from different systems and may have different interval start/stop times associated with it. The settlement calculations will need to accommodate these differences and align relevant data for calculations as may be appropriate for each ISO/region.

3. Application of BTC Charges Timeline

The charts below are based on current 20 min IDC calculation cycle.

a) TLR Level 3a called for Next Hour

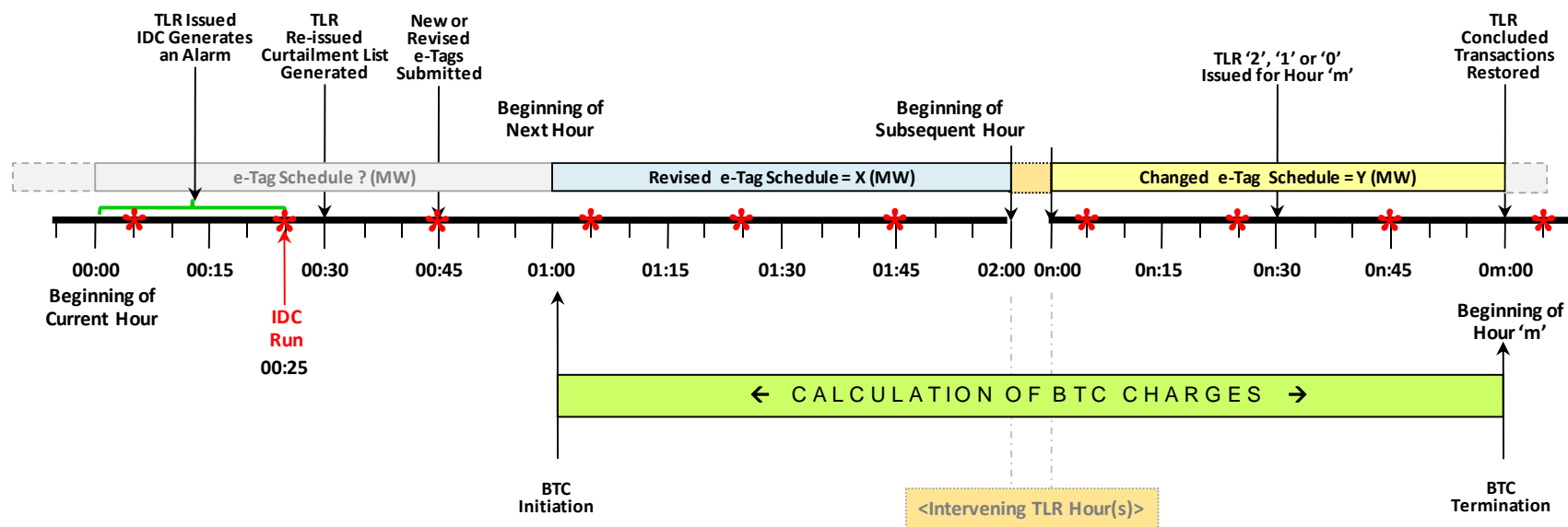


Figure 13 TLR 3a BTC Charge Calculation Timeline

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b) TLR Level 3b called for Current and Next Hour

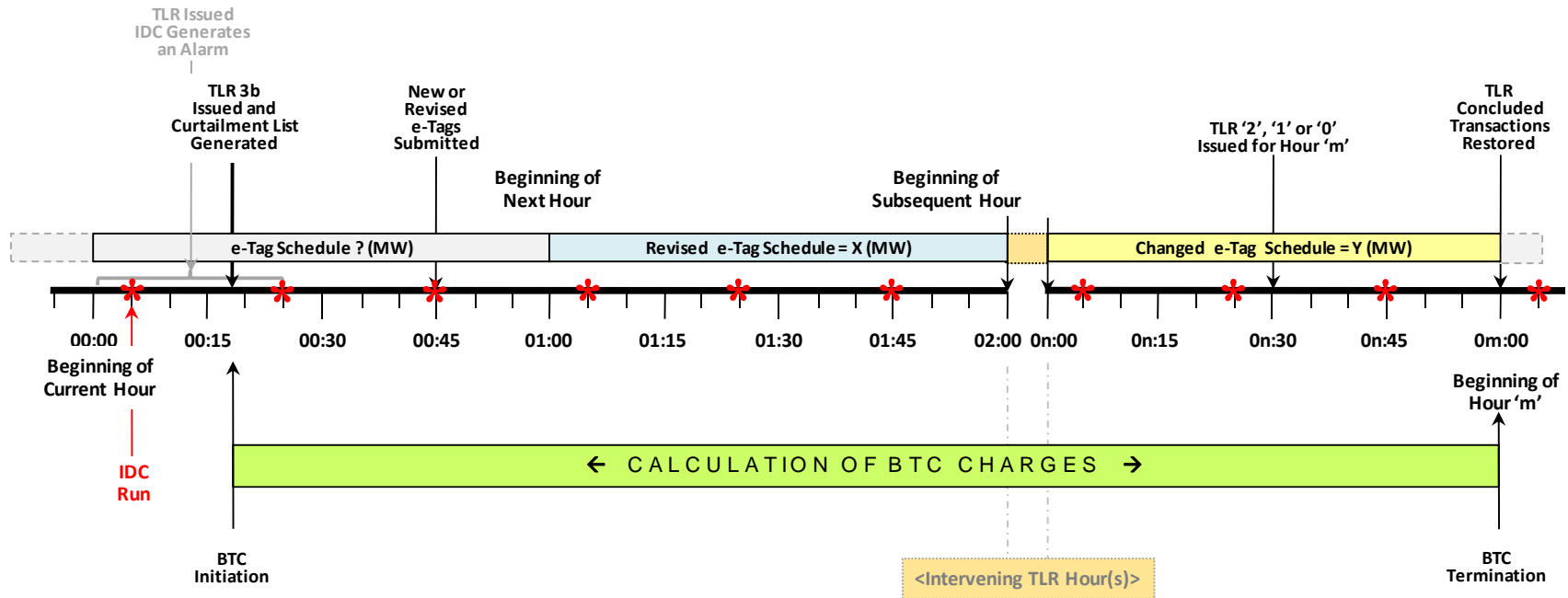


Figure 14 TLR 3b BTC Charge Calculation Timeline

4. Forward Flow – Settlement Equations

The BTC charges for a forward flow transaction across a congested element or flowgate are calculated in accordance with the following settlement equations. Flowgate ‘g’ is the monitored flowgate for which a TLR level 3a or higher has been initiated and continues to exist.

The BTC charge per interval for off-contract path loop flow for transaction ‘k’ through a congested element or flowgate, ‘g’, in a monitoring ISO is to be calculated on the basis of:

Loop flow (in MW/h) for transaction ‘k’ across flowgate ‘g’ *multiplied by the unit congestion cost* across the flowgate ‘g’ (in \$/MW/h) *divided by the number of intervals in an hour (this assumes all intervals are of equal length; if not multiply by number of seconds in the interval divided by 3600), or*

The MW of the scheduled transaction *multiplied by the price differential between the external boundary nodes the monitoring ISO uses to represent the source and sink of the transaction divided by the number of intervals in an hour.*

The BTC charge for a transaction ‘k’ is summed over the all of the intervals from **initiation of the BTC event** until the **termination of the BTC event**. That is, the total BTC charge for transaction ‘k’ is:

BTC Termination

$$\sum_{i = \text{BTC Initiation}}^{\text{BTC Termination}} ((\text{Loop_flow}_{k,g})_i \times (\text{Unit Congestion Cost}_{g,i}) \div \text{intervals/h})$$

where:

The **BTC Initiation** time is the TLR Effective (or “start”) Time as denoted on the TLR Issuing Screen for a TLR 3a or higher;

The **BTC Termination** time is the TLR Effective (or “start”) Time as denoted on the TLR for a reduction to a TLR level 2, or the issuance of a TLR Level 0 (i.e. “TLR concluded”) for the subject flowgate; and

The **Unit Congestion Cost** is the shadow cost of the (active) constraint on the subject flowgate.

And:

$$\begin{aligned} \text{Loop_flow}_{g'} \text{ for Transaction }_{k'} \\ = (\text{Transfer Distribution Factor}_{g'} \text{ for Transaction }_{k'}) \\ \times (\text{e-Tag Schedule Amount for Transaction }_{k'}) \end{aligned}$$

$$\begin{aligned} \text{Loop_flow}_{k,g,i} = \text{Transfer Distribution Factor}_{k,g,i} \\ \times \text{e-Tag Schedule Amount}_{k,i} \end{aligned}$$

The Transfer Distribution Factor (TDF) used in the settlement calculation for a transaction is the TDF for that transaction as reported in the IDC run applicable to the identified interval(s).

A BTC charge is calculated only for those intervals in which the transaction's TDF is greater than or equal to 5%. If the transaction's transfer distribution factor is ≤ 0.05 (i.e. $\leq 5\%$) then this factor is set equal to zero for the calculation above (or or the transaction's loop flow is set to zero, or no calculation at all needs to be performed).

Similarly the e-Tag schedule amount for the identified interval corresponds to the e-Tag schedule prevailing during that interval. If the transaction's NERC e-Tag flag for the monitoring ISO is set to NBT then the transaction's transfer distribution factor for the calculation above is set equal to zero (or or the transaction's loop flow is set to zero, or no calculation at all needs to be performed).

5. Counter Flow

Off-contract path flows which are having a counter-flow 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. In the determination of the settlement amounts associated with BTC credits for congestion relief the payments for congestion relief in an interval must not exceed the collection of BTC charges from forward flow WBT transactions in the same interval. Where payments for congestion relief would otherwise exceed the collection of BTC charges in

an interval, the payments will be prorated so that they equal the charges collected in the interval.

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.

6. Counter Flow – Settlement Equations

The Congestion Relief Payments in interval ‘i’ to transaction ‘k’ for off-contract path counter-flow loop flow through congested element or flowgate ‘g’ is calculated on the basis of:

Counter-flow Loop flow (in MW) for transaction ‘k’ across flowgate ‘g’ *multiplied by* the **unit congestion cost** across the flowgate ‘g’ (in \$/MW),
or

The MW of the schedule transaction *multiplied by* the price differential between the external boundary nodes the monitoring ISO uses to represent the source and sink of the transaction;

multiplied by the **settlement sufficiency factor, SSF**, for the interval and *divided by* the number of intervals in an hour

The Congestion Relief Payments for transaction ‘k’ is summed over the all of the intervals from **initiation of the BTC event** until the **termination of the BTC event**. That is, the total Congestion Relief Payment for transaction ‘k’ is:

BTC Termination

$$\sum_{i = \text{BTC Initiation}} \text{SSF}_{g,i} \times ((\text{Loop_flow}_{\text{CF } k,g})_i \times (\text{Unit Congestion Cost }_g)_i \div \text{intervals/h})$$

where:

$$\text{SSF}_{g,i} = 1 \quad \text{if} \quad \sum_{k=1}^{\text{all Transactions}} \text{Congestion Relief Payments}_{k,g,i} \leq \sum_{k=1}^{\text{all Transactions}} \text{BTC Charge}_{k,g,i}$$

and

$$\text{SSF}_{g,i} = \frac{\sum_{k=1}^{\text{all Transactions}} \text{BTC Charge}_{k,g,i}}{\sum_{k=1}^{\text{all Transactions}} \text{Congestion Relief Payments}_{k,g,i}}$$

$$\text{if} \quad \sum_{k=1}^{\text{all Transactions}} \text{Congestion Relief Payments}_{k,g,i} > \sum_{k=1}^{\text{all Transactions}} \text{BTC Charge}_{k,g,i}$$

NOTE* - This formulation requires two passes of the calculations; the first to calculate the $\text{SSF}_{g,i}$, then a second pass to calculate the final Congestion Relief Payments for settlement.**

7. Data Sources

DATA	UNITS	SOURCE
BTC Initiation time	mm/dd/yyyy hh:mm (CST?)	IDC Congestion Management Report
BTC Termination time	mm/dd/yyyy hh:mm (CST?)	IDC Congestion Management Report
Transfer Distribution Factor (TDF)	%	IDC Report prevailing for the subject interval []
e-Tag Schedule (or “Level”?)	MW (/h)	Transaction Information System (TIS)

x. Outstanding Elements

1. Firm Transmission Service Treatment

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 are 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 BAs, multiple products may need to be acquired.

2. Up-to Congestion Charge Bidding Indicators

Stakeholders 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 region’s internal load to the transacting parties whose schedules produce the off-contract path congestion. It is not currently expected that the initial implementation of BTC will include the ability to specify an “up-to” congestion component on real-time congestion until the following issues can be addressed:

- **Congestion Cost Determination:** Forecasting congestion for a subsequent entire hour is subject to considerable uncertainty. The existing TLR protocol does not provide for the ability to instantaneously curtail transaction schedules upon invocation or triggering conditions. Time delays exist and are acknowledged within the protocol. As such, forecasted expectation of congestion across parallel paths would need to be utilized to perform an evaluation of congestion charge exposure against a transaction schedule duration that is still subject to revision. Additionally, a forecast congestion cost component cannot take into consideration the effects on congestion resulting from changes in transaction schedules introduced via the BTC protocols, or revisions to transaction schedules introduced through normal ISO scheduling practices. Such forecasts are likely not sufficiently accurate to support an accurate evaluation of “up-to” bidding.
- **Risk Transfer:** Expecting that the ISOs and RTOs would hold MPs harmless to their up-to bids, then unexpected events that create market volatility could lead to substantial shortfalls and uplift costs when actual congestion costs exceeded the “up-to” bids of transactions, since it is not possible to immediately evaluate and remove the uneconomic transactions. Effectively, using an “up-to” component would move the risk from the entity that scheduled an External Transaction to the entities that are responsible for covering uplift in each market. Entities that did not participate in the decision to schedule an External Transaction would be made financially responsible for insulating the scheduling MP from the market risk associated with its External Transaction. The better choice is to place the risk on the entity that is scheduling an external transaction that has potential parallel path impacts.
- **Desirability:** Of the ISO’s around Lake Erie, PJM is the only ISO that currently offers a real-time “up-to” transaction product that evaluates real-time intra-market congestion cost exposure. Currently, experience with that product has demonstrated a lack of interest in the feature as it is generally unused within the markets. Prior to incurring the additional cost and added infrastructure of a different real-time “up-to” congestion cost product the incremental value of that product would need to be justified.

To the extent that an “up-to” bid is not available that would allow an MP to mitigate, or cap, the potential exposure to BTC costs, there remain several opportunities to hedge the cost exposure or avoid the resulting costs. As described in section 4.b.vi, hedging opportunities exist in the markets to procure transmission services in the Day-Ahead Market at user-defined thresholds of cost exposure. Additionally, MPs can (1) self-curtail their schedules along the contract path following standard ISO schedule practices; (2) initiate counter flow transaction over the constrained flowgate; or (3) choose to not participate in the BTC service procurement.

3. Congestion Cost Determination: LBMP or Shadow Costs

Two methods for determining congestion cost attributed to parallel flow resulting from a transaction are currently under discussion. One method, the “shadow cost method”, uses the shadow cost on a constrained flowgate and the amount of the transaction’s parallel flow (calculated by the TDF) on the flowgate to determine the cost. The second method, the “LMP delta method”, uses the difference between the applicable LMPs that represent the external source and sink proxy buses, as calculated by the monitoring ISO, and the entire scheduled transaction to determine the cost.

Using the shadow cost method, TDFs on flowgates for scheduled transactions are obtained from the IDC. Shadow costs are computed by the ISOs and are, or can be, posted on the ISOs’ websites. From these, congestion costs attributed to parallel flows can be calculated at settlement intervals.

With the LMP delta method, prices at the source and sink of the transaction are determined by the monitoring ISO. In some cases, these prices may be proxy prices at the external borders closest to the actual source and sink. The delta between the two LMPs is applied to the entire scheduled transaction to determine the applicable congestion cost.

Given the following assumptions, either method should yield the same result:

- The TDFs on the constrained flowgates are accurately computed by the IDC and consistent with the monitoring ISO’s assessment;
- External proxy prices accurately reflect shadow costs experienced by the monitoring ISO; and
- Given that external proxy prices are accurately computed, the correct proxies are selected when an LMP delta is calculated.

c. Congestion Management through Market to Market Dispatch

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 region's 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)

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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 RCFs.

RCFs 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 RCFs will meet the following three criteria:

- It will meet the criteria for CF 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 CF 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 CF 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 redispach 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 CF that has similar Market Flows and tag impacts as the temporary flowgate. In this case, an Operating Entity would have to realize relief through redispach 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 CFs. 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 CFs. 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 RCs the following information:

- Firm Market Flows for all CFs in each direction
- Non-Firm Market Flows for all CFs 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 RCs the amount of flows to be considered firm on the various CFs 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 RC 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 RCs 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 CFs under the functional control of Market-Based Operating Entities and the allocations of all RCFs will be honored.

For CFs, 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 CF. At any given time, an entity must use only one method for all CFs 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 CFs and RCFs. 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 CFs. 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 CFs 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 RC, 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 RC 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 BAs' 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 BA'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 BA basis. The impact of GTL will be determined for CFs.
2. The Flowgate impact will be determined based on individual generators serving aggregated BA load. Only generators that are Designated Network Resources for the BA 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 BA 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. BA 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 BA net interchange to the extent they are located outside the BA 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 BA 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:

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

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:

$$\text{Payment} = ((\text{Firm Flow Entitlement MW2} + \text{Approved MW3}) - \text{Real-Time Market Flow MW1}) * \text{Transmission Constraint Shadow Price in Non-Monitoring RTOs Dispatch Solution}$$

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. Interregional Scheduling Enhancements

i. Interchange Optimization

PJM and MISO are exploring alternatives for optimizing the net interchange between the two RTOs. This is aimed at increasing economic efficiency by lowering overall operating costs across the two markets in the real-time and would result in better matching of real-time prices at the seam between the RTOs.

1. Coordinated Regional Dispatch

In both PJM and MISO, interchange transactions are scheduled to start/end on 15-minute intervals at :00, :15, :30 and :45 minutes past the hour. The objective of the Coordinated Regional Dispatch process will be to jointly determine the optimal energy interchange at the target quarter-hour interval. Depending on the timings and sequence of processes involved, the target interval would be the one following the immediate next, upcoming

quarter-hour interval. It is important to align the timing of this process with each RTO's interchange schedule notification deadline and NSI checkout timeline.

The basis for this process would be the solution from each RTO's look-ahead Security Constrained Economic Dispatch (SCED) execution. PJM has recently implemented the Generation Control Application (GCA) enhancements under which the RT SCED dispatches energy and reserves on online, dispatchable resources at 10-20 minute look-ahead basis. This functionality provides the capability to project the dispatch of individual resources and resolve any dispatch constraints prior to solving the final Security Constraint Economic Dispatch (SCED) case for clearing the real-time market. MISO is planning to implement a similar capability in the near future. These look-ahead SCED analyses can be augmented to incorporate the functionality that will allow coordinated determination of the optimal level of net interchange between the RTOs. The level of optimal interchange determined in this process will be driven by the Market Participant bids and offers at the respective RTOs and the estimated system conditions.

Scheduling of the optimal interchange can be facilitated jointly by the RTOs. Another approach will be based on economic clearing of inter-regional transaction offers submitted by Market Participants. Inter-regional transaction offers would involve submission of offers to move energy from one RTO to the other, with an offer price associated with price separation between the markets. The dispatch would be based on the anticipated price separation between the two markets such that the RTOs could economically determine the set of transactions that would as nearly as possible optimize the interchange. The cleared transactions will be settled individually by each RTO with the scheduling market participants based on either price estimates determined ex ante or actual prices ex post.

2. Economic Clearing of Import/Export Transactions

Provisioning of economic clearing of import and export transactions at the real-time market of each RTO may also provide the Market Participants better capability to schedule such transactions more efficiently leading to general improvement of efficiency of interchange across the interface. The New York ISO currently provides this facility with hourly scheduling requirement and is currently evaluating an enhancement to implement further granularity similar to PJM and MISO.

Under this construct, participants will submit import or export transactions to each RTO based on their projections of system requirements and price estimates. Each RTO will evaluate the transactions similar to price sensitive generation offers / load bids with source/sink at the external interface pricing node. Final clearing of the transactions can be coordinated among the RTOs to ensure that the cleared schedules are acceptable by both RTOs prior to submittal of the tags for approval and checkout. Timing of clearing and target interval need to be coordinated based on existing dispatch frequencies. The cleared transactions will be settled individually by each RTO with the scheduling market participants based on either price estimates determined ex ante or actual prices ex post.

ii. Enhanced Interregional Transaction Coordination (EITC)

1. 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, EITC 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.

EITC 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.

2. Bidding and Scheduling

It is envisioned that all transactions scheduled between BAs 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 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.

Depending on the NYISO border, EITC 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 HQ where intra-hour transactions would be scheduled on a five minute basis. Hourly schedules with HQ will be created by Real-Time Commitment ('RTC') and those schedules with the more flexible intra-hour bid energy profiles will be checked out with HQ prior to the dispatch hour. This will allow HQ to establish the operating band of the DC tie with NY. 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 HQ. The five minute interchange will be communicated to HQ 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 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 RTD 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 EITC 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 LBMPs, 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 LBMPs using the average RTC LMP as the reference.

e. Market Modeling

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 the NYISO is pursuing modifications to its interface pricing methodology. As such the NYISO has proposed to its stakeholder community to evaluate its interface price methodologies with regards to:

- The recognition of the incremental distribution of power flows around Lake Erie when evaluating and pricing the marginal impacts of transaction and generation schedules such that:
 - The existing allocation of power flows on the NYISO-PJM PARs shall be maintained; no incremental power flows due to circulation will be reflected on the NYISO-PJM PAR controlled lines; and
 - Consistent treatment will be maintained between external transactions and internal resources for both scheduling and pricing decisions.
- The validation of scheduling paths:
 - As discussed in Section 3.c. the NYISO does not consider circuitous path scheduling appropriate in the absence of the ability to conform actual flows to scheduled flows and will continue to maintain circuitous path prohibitions and path validations; but
 - The NYISO will monitor the ability of the IESO-Midwest ISO PARs, in conjunction with the BRM solutions, to maintain actual flow to be consistent with scheduled interchange. When actual power flows around Lake Erie a closely aligned with schedules, the NYISO will work with PJM, IESO and the Midwest ISO to determine if it is appropriate to remove the path validations and permit circuitous scheduling.

The NYISO will evaluate the appropriate locations for its proxy buses that represent the PJM and IESO Control Areas. Modifying the electrical location of these facilities may permit the NYISO to better align the anticipated distribution of network power flows

delivered to, from or through PJM or IESO. The NYISO considered the creation of an additional proxy bus to represent the Midwest ISO but is not recommending the establishment of additional proxy bus locations beyond PJM and IESO at this time.

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 PARs 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 PARs 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.

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Glossary

Glossary of Terms Used in Broader Regional Markets Initiative

Term	Acronym	Definition
AFC Flowgate		Any flowgate for which an entity calculates an AFC value.
Auction Revenue Rights	ARR	Midwest ISO: A Market Participant's entitlements to a share of the revenues generated in the annual FTR Auction.
Available Flowgate Capability	AFC	NERC: A measure of the flow capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is defined as TFC less Existing Transmission Commitments (ETC), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, and plus counterflows. ⁴
Available Transfer Capability	ATC	NERC: A measure of the transfer capability remaining in the physical transmission network for further commercial activity over and above already committed uses. It is defined as Total Transfer Capability less Existing Transmission Commitments (including retail customer service), less a Capacity Benefit Margin, less a Transmission Reliability Margin, plus Postbacks, plus counterflows. ⁵
Balancing Authority	BA	NERC: The responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports Interconnection frequency in real time. ⁶
Broader Regional Markets initiative	BRM	
Buy-Through of Congestion	BTC	The assessment of congestion charges from parallel flow impacts associated with scheduling an interregional transaction to the PSE.

⁴ Glossary of Terms Used in NERC Reliability Standards Updated April 20, 2010, p.5

⁵ Id., p.6

⁶ Id., p.7

Term	Acronym	Definition
Commercial Pricing Node	CPNode	Midwest ISO: <i>An Elemental Pricing Node or an Aggregate Price Node in the Commercial Model used to schedule and settle Market Activities. Commercial Pricing Nodes include Resources, Hubs, Load Zones and/or Interfaces.</i> ⁷
Congestion Management	CM	
Congestion Management Program	CMP	
Control Performance Standard	CPS	NERC: <i>The reliability standard that sets the limits of a Balancing Authority's Area Control Error over a specified time period.</i> ⁸
Coordinated Flowgate	CF	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.
Distribution Factor	DF	NERC: <i>The portion of an Interchange Transaction, typically expressed in per unit that flows across a transmission facility (Flowgate)</i> ⁹ .
Disturbance Control Standard	DCS	NERC: <i>The reliability standard that sets the time limit following a Disturbance within which a Balancing Authority must return its Area Control Error to within a specified range.</i> ¹⁰
Electronic Tagging	eTag	The NERC electronic tagging process for transactions.
Energy Management System	EMS	
Enhanced Interregional Transmission Coordination	EITC	

⁷ **OPEN ACCESS TRANSMISSION, ENERGY AND OPERATING RESERVE MARKETS TARIFF FOR THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.,** Section 1.74

⁸ **Glossary of Terms Used in NERC Reliability Standards** *Updated April 20, 2010*, p.11

⁹ *Id.*, p.13

¹⁰ *Id.*, p.14

Term	Acronym	Definition
Financial Impact Charge	FIC	
Financial Responsible Party	FRP	
Financial Transmission Right	FTR	Midwest ISO: <i>A financial instrument that entitles the holder to receive compensation for or requires the holder to pay certain congestion related transmission charges that arise when the Transmission System is congested and differences in LMPs result from the redispatch of Resources out of economic merit order to relieve that congestion.</i> ¹¹
Firm Transmission Service		<p>NERC: <i>The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.</i>¹²</p> <p>Midwest ISO: Firm Point-To-Point Transmission Service <i>Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Points of Delivery pursuant to Module B of this Tariff.</i>¹³</p> <p>NYISO: Firm Transmission Service: <i>Transmission Service requested by a Transmission Customer willing to pay Congestion Rent.</i>¹⁴</p> <p>PJM: Firm Point-To-Point Transmission Service: <i>Transmission Service under this Tariff that is reserved and/or scheduled between specified Points of Receipt and Delivery pursuant to Part II of this Tariff.</i>¹⁵</p>

¹¹ **OPEN ACCESS TRANSMISSION, ENERGY AND OPERATING RESERVE MARKETS TARIFF FOR THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.,** Section 1.384

¹² **Glossary of Terms Used in NERC Reliability Standards** Updated April 20, 2010, p.18

¹³ **OPEN ACCESS TRANSMISSION, ENERGY AND OPERATING RESERVE MARKETS TARIFF FOR THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.,** Section 1.231

¹⁴ **NYISO Tariffs – OATT Body** Document Generated On: 6/30/2010, Section 1.6

¹⁵ **PJM OPEN ACCESS TRANSMISSION TARIFF,** Section 1.13

Term	Acronym	Definition
Flowgate		NERC: 1.) A portion of the Transmission system through which the Interchange Distribution Calculator calculates the power flow from Interchange Transactions. 2.) A mathematical construct, comprised of one or more monitored transmission Facilities and optionally one or more contingency Facilities, used to analyze the impact of power flows upon the Bulk Electric System. ¹⁶
Generator Control Area	GCA	
Generator to Load	GTL	
Generator-to-Load Distribution Factor	GLDF	NERC: The algebraic sum of a Generator Shift Factor and a Load Shift Factor to determine the total impact of an Interchange Transaction on an identified transmission facility or Flowgate. ¹⁷
Generation Shift Factor	GSF	NERC: A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate. ¹⁸
Hydro Quebec	HQ	
Interchange Authority	IA	NERC: The responsible entity that authorizes implementation of valid and balanced Interchange Schedules between Balancing Authority Areas, and ensures communication of Interchange information for reliability assessment purposes. ¹⁹
Interchange Distribution Calculator	IDC	NERC: The mechanism used by Reliability Coordinators in the Eastern Interconnection to calculate the distribution of Interchange Transactions over specific Flowgates. It includes a database of all Interchange Transactions and a matrix of the Distribution Factors for the Eastern Interconnection. ²⁰
IDC Working Group	IDCWG	A NERC Working Group

¹⁶ **Glossary of Terms Used in NERC Reliability Standards Updated April 20, 2010**, p.19

¹⁷ Id., p.21

¹⁸ Id., p 21

¹⁹ Id., p.22

²⁰ Id., p.22

Term	Acronym	Definition
Independent Electricity System Operator	IESO	
Interconnection Reliability Operating Limit	IROL	NERC: <i>A System Operating Limit that, if violated, could lead to instability, uncontrolled separation, or Cascading Outages that adversely impact the reliability of the Bulk Electric System.</i> ²¹
Independent System Operator	ISO	
Independent System Operator – New England	ISO-NE	
Inter-Control Center Communications Protocol	ICCP	
Joint Operating Agreement	JOA	A joint operating agreement among two or more BAs.
Lake Erie Circulation	LEC	
Lake Erie Loop Flow	LELF	
Load Control Area	LCA	
Load Shift Factor	LSF	NERC: <i>A factor to be applied to a load's expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or monitored Flowgate.</i> ²²
Locational Based Marginal Price	LBMP	NYISO: <i>The price of Energy at each location in the NYS Transmission System as calculated pursuant to Section 17 Attachment B of this Services Tariff.</i> ²³

²¹ Id. p.23

²² Id., p.25

²³ **NYISO Tariffs – MST Body** Document Generated On: 11/11/2010, Section 2.12

Term	Acronym	Definition
Locational Marginal Price	LMP	Midwest ISO: <i>The market clearing price for Energy at a given Commercial Pricing Node in the Transmission Provider Region which shall be equivalent to the marginal cost of serving demand at the Commercial Pricing Node while meeting Zonal and Market-Wide Operating Reserve Requirements.</i> ²⁴
Market to Market	M2M	A joint dispatch between two or more BAs.
Market Entity	ME	A BA within the BRM initiative (IESO, Midwest ISO, NYISO and PJM)
Midwest Independent System Operator	Midwest ISO (preferred) or MISO	
Market Participant	MP	Midwest ISO: <i>An entity that (i) has successfully completed the registration process with the Transmission Provider and is qualified by the Transmission Provider as a Market Participant, (ii) is financially responsible to the Transmission Provider for all of its Market Activities and obligations, and (iii) has demonstrated the capability to participate in its relevant Market Activities.</i> ²⁵ NYISO: <i>An entity, excluding the ISO, that produces, transmits, sells, and/or purchases for resale Capacity, Energy and Ancillary Services in the Wholesale Market. Market Participants include: Transmission Customers under the ISO OATT, Customers under the ISO Services Tariff, Power Exchanges, Transmission Owners, Primary Holders, LSEs, Suppliers and their designated agents. Market Participants also include entities buying or selling TCCs.</i> ²⁶
Market Services Tariff	MST	NYISO Market Services Tariff (“Services Tariff”)
Monitoring ISO		The ISO responsible for monitoring and controlling a constrained flowgate.

²⁴ **OPEN ACCESS TRANSMISSION, ENERGY AND OPERATING RESERVE MARKETS TARIFF FOR THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.**, Section 1.366

²⁵ Id., Section 1.384

²⁶ **NYISO Tariffs – OATT Body** Document Generated On: 6/30/2010, Section 1.13

Term	Acronym	Definition
Net Scheduled Interchange	NSI	NERC: <i>The algebraic sum of all Interchange Schedules across a given path or between Balancing Authorities for a given period or instant in time.</i> ²⁷
New York Control Area	NYCA	NYISO: <i>The Control Area that is under the control of the ISO which includes transmission facilities listed in the ISO/TO Agreement Appendices A - 1 and A - 2, as amended from time-to-time, and Generation located outside the NYS Power System that is subject to protocols (e.g., telemetry signal biasing) which allow the ISO and other Control Area operator(s) to treat some or all of that Generation as though it were part of the NYS Power System.</i> ²⁸

²⁷ **Glossary of Terms Used in NERC Reliability Standards** Updated April 20, 2010, p.26

²⁸ **NYISO Tariffs – OATT Body** Document Generated On: 6/30/2010, Section 1.14

Term	Acronym	Definition
New York Independent System Operator	NYISO	
Non-Firm Transmission Service	NF	<p>NERC: <i>Transmission service that is reserved on an as-available basis and is subject to curtailment or interruption.</i>²⁹</p> <p>Midwest ISO: Non-Firm Point-To-Point Transmission Service: <i>Point-To-Point Transmission Service under this Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one (1) hour to one (1) month.</i>³⁰</p> <p>NYISO: Non-Firm Point-To-Point Transmission Service: <i>Point-To-Point Transmission Service under the Tariff for which a Transmission Customer is not willing to pay Congestion. Such service is available absent Constraints under Part 3 of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for individual one-hour periods not to exceed twenty-four (24) consecutive hours.</i>³¹</p> <p>PJM: Non-Firm Point-To-Point Transmission Service: <i>Point-To-Point Transmission Service under the Tariff that is reserved and scheduled on an as-available basis and is subject to Curtailment or Interruption as set forth in Section 14.7 under Part II of this Tariff. Non-Firm Point-To-Point Transmission Service is available on a stand-alone basis for periods ranging from one hour to one month.</i>³²</p>
Non-Market Entity	NME	A entity existing in a BA outside of the BRM initiative

²⁹ **Glossary of Terms Used in NERC Reliability Standards Updated April 20, 2010,** p.26

³⁰ **OPEN ACCESS TRANSMISSION, ENERGY AND OPERATING RESERVE MARKETS TARIFF FOR THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.,** Section 1.462

³¹ **NYISO Tariffs – OATT Body** Document Generated On: 6/30/2010, Section 1.14

³² **PJM OPEN ACCESS TRANSMISSION TARIFF,** Section 1.27

Term	Acronym	Definition
Non-Market Transaction:	NMT	A transaction scheduled by a PSE not residing in a BA of the BTC market area (IESO, Midwest ISO, NYISO or PJM).
North American Electric Reliability Corp.	NERC	
North American Energy Standards Board	NAESB	
Not willing to Buy Through	NBT	Not willing to pay for congestion in a BTC market.
Ontario Energy Board	OEB	
Open Access Same time Information Service	OASIS	NERC: <i>An electronic posting system that the Transmission Service Provider maintains for transmission access data and that allows all transmission customers to view the data simultaneously.</i> ³³
Open Access Technology International, Inc.	OATI	The vendor responsible for the development and maintenance of the IDC
Open Access Transmission Tariff	OATT	NERC: <i>Electronic transmission tariff accepted by the U.S. Federal Energy Regulatory Commission requiring the Transmission Service Provider to furnish to all shippers with non-discriminating service comparable to that provided by Transmission Owners to themselves.</i> ³⁴
Operating Reliability Subcommittee	ORS	A NERC Subcommittee
Phase Angle Regulator	PAR	
Parallel Flow Visualization	PFV	The visualization (graphical and otherwise) of all actual loop and parallel flows caused by a scheduled transaction.
PJM Interconnection	PJM	

³³ **Glossary of Terms Used in NERC Reliability Standards Updated April 20, 2010,**
p.28

³⁴ *Id.*, p.28

Term	Acronym	Definition
Purchasing – Selling Entity	PSE	NERC: <i>The entity that purchases or sells, and takes title to, energy, capacity, and Interconnected Operations Services. Purchasing-Selling Entities may be affiliated or unaffiliated merchants and may or may not own generating facilities.</i> ³⁵
Real-Time Commitment	RTC	NYISO: <i>A multi - period security constrained unit commitment and dispatch model that co - optimizes to solve simultaneously for Load, Operating Reserves and Regulation Service on a least as - bid production cost basis over a two hour and fifteen minute optimization period. The optimization evaluates the next ten points in time separated by fifteen minute intervals. Each RTC run within an hour shall have a designation indicating the time at which its results are posted; “RTC00,” RTC15,” “RTC30,” and “RTC45” post on the hour, and at fifteen, thirty, and forty - five minutes after the hour, respectively. Each RTC run will produce binding commitment instructions for the periods beginning fifteen and thirty minutes after its scheduled posting time and will produce advisory commitment guidance for the remainder of the optimization period. RTC15 will also establish External Transaction schedules. Additional information about RTC’s functions is provided in Section 4.4.2 of the ISO Services Tariff.</i> ³⁶
Real Time Contingency Analysis	RTCA	

³⁵ Id., p.32

³⁶ NYISO Tariffs – OATT Body Document Generated On: 6/30/2010, Section 1.18

Term	Acronym	Definition
Real-Time Dispatch	RTD	NYISO: <i>A multi - period security constrained dispatch model that co-optimizes to solve simultaneously for Load, Operating Reserves, and Regulation Service on a least - as - bid production cost basis over a fifty, fifty - five or sixty - minute period (depending on when each RTD run covers within an hour). The Real - Time Dispatch dispatches, but does not commit Resources, except that RTD may commit, for pricing purposes, Resources meeting Minimum Generation Levels and capable of starting in ten minutes. Real - Time Dispatch runs will normally occur every five minutes³⁷.</i>
Real-Time Dispatch – Corrective Action Mode	RTD-CAM	NYISO: <i>A specialized version of the Real - Time Dispatch software that will be activated when it is needed to address unanticipated system conditions. RTD - CAM is described in Section 4.4.4 of the ISO Services Tariff.³⁸</i>
Reciprocal Coordinated Flowgate	RCF	<ol style="list-style-type: none"> 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.

³⁷ Id.

³⁸ Id.

Term	Acronym	Definition
Regional Transmission Operator	RTO	
Reliability Coordinator	RC	NERC: <i>The entity that is the highest level of authority who is responsible for the reliable operation of the Bulk Electric System, has the Wide Area view of the Bulk Electric System, and has the operating tools, processes and procedures, including the authority to prevent or mitigate emergency operating situations in both next-day analysis and real-time operations. The Reliability Coordinator has the purview that is broad enough to enable the calculation of Interconnection Reliability Operating Limits, which may be based on the operating parameters of transmission systems beyond any Transmission Operator's vision.</i> ³⁹
Reliability Coordinator Information System	RCIS	NERC: <i>The system that Reliability Coordinators use to post messages and share operating information in real time.</i> ⁴⁰
Responsible Balancing Authority	RBA	
Request for Interchange	RFI	NERC: <i>A collection of data as defined in the NAESB RFI Datasheet, to be submitted to the Interchange Authority for the purpose of implementing bilateral Interchange between a Source and Sink Balancing Authority.</i> ⁴¹
Settlement Sufficiency Factor	SSF	
Supervisory Control and Data Acquisition	SCADA	NERC: <i>A system of remote control and telemetry used to monitor and control the transmission system.</i> ⁴²

³⁹ Glossary of Terms Used in NERC Reliability Standards Updated April 20, 2010., p.35

⁴⁰ Id., p.35

⁴¹ Id, p. 36

⁴² Id., p.39

Term	Acronym	Definition
System Data eXchange	SDX	
System Operating Limit	SOL	<p>NERC: <i>The value (such as MW, MVar, Amperes, Frequency or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria. System Operating Limits are based upon certain operating criteria. These include, but are not limited to:</i></p> <ul style="list-style-type: none"> • <i>Facility Ratings (Applicable pre- and post-Contingency equipment or facility ratings)</i> • <i>Transient Stability Ratings (Applicable pre- and post-Contingency Stability Limits)</i> • <i>Voltage Stability Ratings (Applicable pre- and post-Contingency Voltage Stability)</i> • <i>System Voltage Limits (Applicable pre- and post-Contingency Voltage Limits)</i>⁴³
Total Transfer Capability	TTC	<p>NERC: <i>The amount of electric power that can be moved or transferred reliably from one area to another area of the interconnected transmission systems by way of all transmission lines (or paths) between those areas under specified system conditions.</i>⁴⁴</p>
Transaction Information System	TIS	
Transfer Distribution Factor	TDF	<p>NERC: <i>See Distribution Factor.</i>⁴⁵</p>
Transmission Congestion Contract	TCC	<p>NYISO: <i>The right to collect or obligation to pay Congestion Rents in the Day - Ahead Market for Energy associated with a single MW of transmission between a specified POI and POW. TCCs are financial instruments that enable Energy buyers and sellers to hedge fluctuations in the price of transmission.</i>⁴⁶</p>

⁴³ Id., p.40

⁴⁴ Id., p.42

⁴⁵ Id.

⁴⁶ **NYISO Tariffs – OATT Body** Document Generated On: 6/30/2010, Section 1.20

Term	Acronym	Definition
Transmission Customer		NERC: 1. Any eligible customer (or its designated agent) that can or does execute a transmission service agreement or can or does receive transmission service. 2. Any of the following responsible entities: Generator Owner, Load-Serving Entity, or Purchasing-Selling Entity ⁴⁷ .
Transmission Loading Relief ⁴⁸	TLR	
Transmission Service		NERC: Services provided to the Transmission Customer by the Transmission Service Provider to move energy from a Point of Receipt to a Point of Delivery. ⁴⁹
Transmission Service Provider	TSP	NERC: The entity that administers the transmission tariff and provides Transmission Service to Transmission Customers under applicable transmission service agreements. ⁵⁰
Transmission Service Reservation	TSR	
Unit Dispatch System	UDS	
Willing to Buy Through	WBT	Willing to pay for congestion in a BTC market.

⁴⁷ Glossary of Terms Used in NERC Reliability Standards Updated April 20, 2010., p.43

⁴⁸ NERC Standard IRO-006-4.1 – Reliability Coordination – Transmission Loading Relief

⁴⁹ Glossary of Terms Used in NERC Reliability Standards Updated April 20, 2010, p.44

⁵⁰ Id.