Section – 8 Appendices

Appendix A – Glossary

Allocation – a calculated share of capability on a Reciprocal Coordinated Flowgate to be used by Reciprocal Entities when coordinating AFC, transmission sales, and dispatch of generation resources.

Control Area – an electric power system or combination of electric power systems to which an common automatic generation control scheme is applied.

Control Zones – Within an Operating Entity Control Area that is operating with a common economic dispatch, the Operating Entity footprint is divided into Control Zones to provide specific zonal regulation and operating reserve requirements in order to facilitate reliability and overall load balancing. The zones must be bounded by adequate telemetry to balance generation and load within the zone utilizing automatic generation control.

Coordinated Flowgate – Coordinated Flowgate or "CF" shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of this document. For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion Management portion of this document (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a third party.

Designated Resource – A generator that has been identified as a designated network resource pursuant to a transmission provider's Open Acces Transmission Tariff.

Economic Dispatch Flow – that portion of Market Flow related to a Market Based Operating Entity's market operations in excess of that entity's Firm Gen-to-Load Flow.

Firm Flow – the estimated impacts of firm Network and Point-to-Point service on a particular Coordinated Flowgate.

Firm Flow Limit – the maximum value of Firm Flows an entity can have on a Reciprocal Coordinated Flowgate, as calculated in the reciprocal Allocation process as defined in this document.

Firm Gen-to-Load Limit – the maximum amount of Market Flows on an RCF that can be considered firm based on the reciprocal Allocation process as defined in this document.

Firm Gen-to-Load Flow – the portion of Market Flow on a Coordinated Flowgate related to contributions from the native load serving aspects of the dispatch (constrained as appropriate by the Firm Gen-to-Load Limit).

Flowgate – a representative modeling of facilities or groups of facilities that may act as significant constraint points on the regional system.

Historic Firm Flow – the estimated total impact an entity has on a Reciprocal Coordinated Flowgate when considering the impacts of 1.) its historic Designated Resources serving native load, and 2.) its imports and exports, based on point-to-point reservations that meet the "freeze date" criteria.

Historic Firm Gen-to-Load Flow – the flow associated with the native load serving aspects of dispatch that would have occurred if all Control Areas maintained their current configuration and continued to serve their native load with their generation.

Historic Ratio – the ratio of Historic Firm Flow of one reciprocal entity compared to the Historic Firm Flow of all reciprocal entities on a specific Reciprocal Coordinated Flowgate.

LMP Based System or Market – An LMP based system or market utilizes a physical, flow-based pricing system to price internal energy purchases and sales.

Locational Marginal Pricing (LMP) – the processes related to the determination of the LMP, which is the market clearing price for energy at a given location in a MBOE's market area.

Market Flows – the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources within a Market Based Operating Entity's market (excluding tagged transactions).

Market-Based Operating Entity (MBOE) – An Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

Network and Native Load (NNL) Impact - Network and Native Load Impact is the impact of generation resources serving internal system load, based on generation the network customer designates for Network Integration Transmission Service (NITS). Also referred to as "Gen-to-Load" impact.

Operating Entity – An entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

Reciprocal Agreement – an agreement between parties to implement the reciprocal coordination procedures defined in this document.

Reciprocal Coordinated Flowgate – a Coordinated Flowgate with respect to which a Reciprocal Agreement has been written and to which reciprocal coordination procedures as defined in this document apply. A RCF is either (1) a Coordinated Flowgate affected by the transmission of energy by both parties, or (2) a Flowgate which both parties mutually agree should be a Coordinated Flowgate, and for which reciprocal coordination will occur.

Reciprocal Entity – an entity that coordinates the future-looking management of Flowgate capacity in accordance with a reciprocal agreement as defined in this document.

Security Constrained Dispatch – Security Constrained Dispatch is the utilization of the least cost economic dispatch of generating and demand resources while recognizing and solving transmission constraints over a single Operating Entity Market.

Appendix B – NERC Policy Impacts

The MISO/PJM Policy Review Task Force is working with the MISO and PJM to identify what Policy changes may be necessary to enable the expansion of the LMP market over the PJM Operating Entity footprint. Appendix B will be modified as necessary to address other impacts that may be noted by the Task Force as their work progresses. The Policy Review Task Force is responsible for coordinating its work with the applicable NERC Subcommittees so that Policy changes can be developed and provided to the NERC Standing Committees for approval.

Appendix C – E-Tag and IDC Impacts

Overview

Much of the following was developed with the assistance of Open Access Technology, International (OATI) and the NERC IDC Working Group.

Proposed Changes

E-Tag Changes

To ensure that the IDC has enhanced granularity for transactions tagged in or out of a large market, MISO and PJM recommend that the IDC be reconfigured to accept the market's marginal units. By providing both the real-time and projected marginal units the IDC will be better able to model where generation is actually moving to support schedule changes. This recommended improvement differs significantly from the current IDC modeling of PJM transactions, because the calculations will not be using a static single point within the PJM system. The actual process for providing these units consists of the following:

a. MISO and PJM will determine these marginal units based upon the look-ahead solutions in their respective Unit Dispatch Systems the locations on the system where generation is expected to be marginal, and upload this information to the IDC.
b. MISO and PJM will indicate where the generation would move depending on the MW amount of curtailments that are necessary. There will be one or more sets of participation factors to represent exports from each market area and one or more sets of participation factors to represent imports into each market area..
c. This information would be transmitted in the form of adjustments to the generation participation factors that are already present in the IDC.
d. The IDC could then utilize this information in the calculation of Control Area to Control Area distribution factors instead of the current methodology of utilizing a static model of all generators within a Control Area's boundaries.
e. These locations could be as granular as individually identified generators. Note though, for market confidentiality reasons Operating Entity will mask the actual generator
f. PJM and MISO each simultaneously optimize and dispatch for all constraints currently confronting the system operators. Upon implementation of the inter-regional congestion coordination scheme, the Operating Entity would add to the current simultaneous constraint evaluation any Flowgate for which the inter-regional congestion

coordination had been initiated. Therefore, the marginal units the Operating Entity would transmit to the IDC for next hour curtailment evaluation would include the simultaneous evaluation of the Flowgate for which curtailments would be requested. The IDC would in fact have all information necessary to accurately determine transaction distribution factors on the constrained facilities.

PJM and MISO propose that they will each supply to the IDC one or more sets of marginal source generators to be used to model all interchange transactions out of their respective markets for all Flowgates. PJM and MISO propose that they will each supply the IDC one or more sets of marginal sink generators to be used to model all interchange transaction into their respective markets for all Flowgates. These sets will be periodically updated by the Operating Entity through a new e-tag message. In addition, each Market Area will be partitioned into zones, and the Operating Entities will send the IDC marginal zone participation factors for more frequent updates. The Operating Entities will provide the IDC with different zonal participation factors for import and export. Depending on the market area configuration, topology, network impedance, geographical location, generation locations, one or more sets of marginal units may be appropriate to represent sinks in the IDC. The IDC should compute different TDFs for tags that source (export) and sink (import) into the market areas, based on the import and export participation factors.

- In order to overcome bandwidth restrictions, the IDC vendor (OATI) suggests PJM to partition its network into zones that can be modeled in the IDC. The number of zones should be small compared to the number of generators. PJM may have at least 12 to as many as 24 different zones. MISO will have at least 30 zones.

- Every hour, the Operating Entities would provide the IDC with the generator participation factors within each zone. The participation factors would be the same for all Flowgates. IDC would calculate TDFs for every source/sink (and zone) for every Flowgate.

- The IDC would publish TDFs for current and next hour for every zone.

- At every LMP cycle, the Operating Entities would provide the IDC with the zone weighting factors that are the same for all Flowgates. Different zone weighting factors can be submitted for import (tags sinking in the market area) and export (tags sourcing in the market area).

- At the time of a TLR the IDC would dynamically compute a market area footprint TDF for import and export based on the most recently received zonal weighting factors, and use the footprint TDF for every tag that sources or sinks in the market area. This can be calculates by:

$TDF_{MA\text{-}Import} = \sum z\ W_{z\text{-}Import}$ x $TDF_z / \sum_z W_{z\text{-}Import}$
$TDF_{MA\text{-}Export} = \sum z\ W_{z\text{-}Export}$ x $TDF_z / \sum_z W_{z\text{-}Export}$

Where:
- o $TDF_{MA\text{-}Import}$ is the Market Area footprint TDF for importing transactions
- o $TDF_{MA\text{-}Export}$ is the Market Area footprint TDF for exporting transactions
- o $W_{z\text{-}Import}$ is the Market Area zone z weighting factor for importing transactions
- o $W_{z\text{-}Export}$ is the Market Area zone z weighting factor for exporting transactions
- o TDF_z is the market Area zone z TDF

- The IDC currently archives the TDFs on a Flowgate in TLR. The IDC would also archive the generator participation factors within the each market area zone and the zonal participation factors at the time the TLR is requested. This would provide the IDC users with the ability to audit the IDC results. The IDC could also update the market area footprint TDF every time the IDC receives new zonal weighting factors from the Operating Entity, which can be used by NERC for presentation through the NERC TDF viewer.

This approach provides the market with knowledge of TDFs, enables the IDC to publish much fewer values to the NERC sites – hourly (current and next hour) TDFs for the market area zones and other Control Areas and updates of the market area footprint TDF throughout the hour. It also reduces the traffic between the IDC and the Market Base Operating Entities, thus minimizing the communication infrastructure enhancement requirements.

Tagged transactions that source or sink in the market area would impact a Flowgate based on the PJM footprint TDF on the Flowgate, which is update throughout the hour based on zonal weighting factors. Transactions wheeled through the market area would only depend on the transactions source and sink TDFs.

IDC Changes

The requirement of this change order was developed to ensure the reliability of the bulk electric system is always maintained, and to ensure the NERC IDC is capable of determining accurate flow gate reductions representative of the entities actually creating the flows on the system. The expanded market footprints include additional Control Areas being incorporated into the existing PJM LMP market and MISO starting its LMP market, and involves the termination of using transmission reservations and NERC tags to represent system flows for those Control Areas internal to each market. The NERC IDC must be capable of receiving flow gate impacts created by each of the LMP markets.

Transactions going in and / or out, and through the PJM territory will continue to be tagged. Source / Sink bus points need to be determined in order to eliminate any type of gaming. During TLR, these tagged transactions will be curtailed as prescribed by the IDC, and could involve any of the current transmission priority buckets. The level of granularity and what E-tagging fields are used by the IDC to assign TDF factors to these transactions will be addressed in the near future.

In order to accomplish these changes necessary to incorporate the LMP markets into the IDC there will be NERC Policy, IDC software, algorithm, and database changes needed.

PROPOSED CHANGE DESCRIPTION:

IDC File Import Requirements:

The LMP market impact files will be sent to the IDC or specified location at least every fifteen minutes. These files will include market impact information for two transmission priorities or categories, for every flow gate identified by the LMP Market agreement. This may not include all Flowgates in the NERC BoF. IDC TDF calculations will continue to be done for the LMP market regions on all Flowgates to ensure that all tagged transactions from / into the market are curtailed properly during the TLR process.

The three transmission priorities that will be included in the LMP market impact file are:

1. Priority 2-NH (non-firm hourly Economic Impacts of LMP Market)
2. Priority 6-NN (Economic Impacts of LMP Market)
3. Priority 7-F (Firm NNL Impacts)

The LMP engine will transfer two types of files to the IDC or specified location. A Current hour file will be sent at least every fifteen minutes, and one next hour file will be sent at (and no later than) 25-minutes after the hour.
Each file will contain flow impact information for priority 2-NH, 6-NN, and 7-F for each identified flow gate. The LMP engine information associated with the flow gate calculations will be posted on the market OASIS for review.

The file transferred to the IDC will be in XML format. The field specifications will be identified when development begins.

If there is an error with the gathering/uploading or content of the LMP market impact file the values from the last good file will be used until a correct file can be retrieved. There should be an error sent to the RC to alert them of the file error.

LMP Flow Gate Impact Calculation Protocol:

Flow gate impact protocol "proposals" are identified in the PJM / MISO Congestion Management White paper. The flow gate protocol process will be added to this NERC IDC change order once a defined process has been approved.

IDC Weighting Factor Algorithm Change Requirements:

Since the LMP markets will be sending the flow impact for specified Flowgates there will be no calculated TDF for that impact for use during the curtailment process. The weighting factor algorithm that is used to calculate the curtailments for priorities 2-NH, 6-NN and 7-FIRM will need to be changed.

The curtailment and reallocation of the priority 2-NH and 6-NN buckets will need to be modified to be like the curtailment in the priority 7-FIRM bucket to allow the flow impact information to be used to assign curtailment amounts on a pro-rata basis (based on the MW level of the MW total to all such Interchange Transactions). Consequently all transactions using 2-NH and 6-NN Transmission Service will be put in the same sub-priority group, and will be Curtailed/Reallocated pro-rata, independent of their current status (curtailed or halted) or time of submittal with respect to TLR issuance. This change will also require a NERC Appendix 9C1 change in language.

The curtailment and reallocation of the priority 7-FIRM bucket will be the same with the exception that NO NNL Responsibility should be calculated for any of the CAs that are in the LMP market. The flow impact that will be sent to the IDC will already include the NNL portion for each area and there would be double counting if the 7-FIRM process also assigned NNL responsibility.

Note that the IDC will remain responsible for calculating RTO NNL Impacts for any Flowgate that is NOT reported by the RTO. For example, if a "Flowgate on the fly" is defined and the RTO has not reported data for that Flowgate, until such time as the RTO does begin reporting such data, the IDC will use its current methods to determine the RTO's impacts on that flowgate.

IDC Curtailment Report Change Requirements:

Non-firm schedule curtailments including transmission priority 1-NS through priority 5-NM will be prescribed for curtailment by the IDC as it is currently done.

Non-firm schedule curtailments of transmission priority 2-NH and 6-NN will include schedules identified by bucket 2-NH and 6-NN NERC tags, and by LMP market economic impacts. For non-firm priority 2-NH and 6-NN curtailments, the IDC curtailment report will prescribe a megawatt reduction requirement for the particular flow gate in TLR for each level as appropriate. The Reliability Coordinator associated with the LMP market having a reduction responsibility will initiate a re-dispatch order representative of the IDC LMP flow gate reduction order, as well as curtail NERC tags sinking into the LMP market. The status of the LMP economic impact will be "Re-Dispatch" until there is no longer a curtailment in the Priority 6-NN bucket where the status will return to "Proceed". The LMP market economic impact should never reach the "HOLD" status, as there will always be a value in the IDC for use (i.e. if there is a problems gathering the information the previous impact should be used).

Firm schedule curtailments of transmission priority #7 will include schedules identified by bucket #7 NERC tags, by Control Area NNL reductions, and by LMP market firm. The firm LMP market impact value used by the IDC will include firm schedules and NNL impacts created by the market as one number. For firm priority #7 curtailments, the IDC firm curtailment report will prescribe a megawatt reduction requirement for the particular flow gate in TLR. The Reliability Coordinator associated with the LMP market having a reduction responsibility will initiate a re-dispatch order representative of the IDC LMP flow gate reduction order, as well as curtail NERC tags sinking into the LMP market. The status of the LMP FIRM impact will be "Re-Dispatch" until there is no longer a curtailment in the Priority 7-FIRM bucket where the status will return to "Proceed". The LMP market Firm impact should never reach the "HOLD" status, as there will always be a value in the IDC for use (i.e. if there is a problems gathering the information the previous impact should be used).

IDC Screen Change Requirements:

Various IDC screen options will be modified in order to display LMP market impacts. For example, when selecting the "whole transaction" list option for a particular flow gate, the IDC will display the LMP priority #6 and #7 accordingly. Some examples are included below.

NERC IDC Display Information:

The following pages represent NERC IDC screen displays. The displays provide information with respect to how the IDC works today, and how the tool will work with the proposed LMP market change order. The Eau Claire – Arpin flow gate was used in the examples. The displays provide information for:

1) IDC “Whole Transaction list” for Eau Claire – Arpin as the tool is today.
2) IDC “Whole Transaction list” for Eau Claire – Arpin with the proposed LMP market change order.
3) TLR level 3B “Eau Claire – Arpin” Curtailment Report (50MWs of relief), as the tool works today, and with the proposed LMP market change order.
4) TLR level 3B “Eau Claire – Arpin” Curtailment Report (155MWs of relief), as the tool works today.
5) TLR level 3B “Eau Claire – Arpin” Curtailment Report (155MWs of relief), with the proposed LMP market change order.
6) TLR level 3B “Eau Claire – Arpin” Curtailment Report (100MWs of relief), with the proposed LMP market change order

Eau Claire – Arpin Flow Gate Information:

The following IDC screen shot represents a NERC IDC "whole transaction" list as it works today.

Sink SC	Method	Tag Name	Reservation MW	Reservation Priority	Reliability Cap	Market Cap	Actual MW	Amount on Flowgate Schedule	Amount on Flowgate Active	TDF (%)
EES	WL	MEC_TNSKDLJAN0278_EES	1 50	1-NS	1 50	1 50	1 50	11.0	11.0	7.1
MISO	WL	OTP_OTPW010007985_MPS	20	1-NS	20	20	20	2.4	2.4	12.2
PJM	CPM	NSP_NSPPOW0092573_PJM	280	1-NS	280	280	280	55.2	55.2	19.7
		Total for 1-NS	**450**		**450**	**450**	**450**	**68.6**	**68.6**	
EES	WL	SECI_CRGL1ASH0107P_EES	25	2-NH	25	25	25	1.4	1.4	5.6
MAIN	WL	MEC_AME010054962_PJM	150	2-NH	150	150	150	11.0	11.0	7.3
MISO	CPM	NSP_NSPPOW0092737_OPPD	6	2-NH	6	6	6	0.8	0.8	13.3
MISO	WL	WAUE_REMC010002263_MPS	250	2-NH	250	250	250	24.0	24.0	9.3
TVA	WL	MEC_APMM1JAN3024_AECI	50	2-NH	50	50	50	3.0	3.0	6.0
TVA	CPM	NSP_NSPPOW0092750_AECI	350	2-NH	350	350	350	69.0	69.0	19.7
		Total for 2-NH	**831**		**831**	**831**	**831**	**109.2**	**109.2**	
PJM	WL	KCPL_CNCTET0005785_PJM	53	3-ND	53	53	53	3.1	3.1	5.8
TVA	WL	NPPD_TEA01TEO3010_AECI	60	3-ND	60	60	60	4.3	4.3	7.2
		Total for 3-ND	**113**		**113**	**113**	**113**	**7.4**	**7.4**	
MISO	CPM	ALTW_ALTMA10008672_ALTE	79	6-NN	79	79	79	12.2	12.2	15.4
MISO	CPM	CE_ALTMA10008643_ALTE	200	6-NN	200	200	200	12.8	12.8	6.4
MISO	CPM	CE_ALTMA10008651_ALTE	150	6-NN	150	150	150	9.6	9.6	6.4
MISO	CPM	OTP_WEPM24000813J_WEC	200	6-NN	200	200	200	51.2	51.2	25.6
MISO	CPM	WAUE_REMC010002261_WEC	300	6-NN	300	300	300	68.1	68.1	22.7
TVA	WL	MEC_APMM1JAN2912_AECI	8	6-NN	8	8	8	0.5	0.5	6.0
		Total for 6-NN	**737**		**737**	**737**	**737**	**86.4**	**86.4**	
MAIN	WL	MEC_CPS010101F00_AMRN	30	7-F	30	30	30	2.2	2.2	7.3
MAIN	WL	MEC_MECBULET01105_CE	360	7-F	360	360	360	38.2	38.2	10.6
MAIN	WL	MEC_MECBULET01106_AMRN	11	7-F	11	11	11	0.8	0.8	7.3
MISO	CPM	ALTE_WPPI010040617_WPS	10	7-F	10	10	10	1.0	1.0	9.6
MISO	CPM	ALTW_ALTMA10008479_ALTE	154	7-F	79	79	79	12.2	12.2	15.4
MISO	CPM	ALTW_ALTMA10008656_ALTE	50	7-F	50	50	50	7.7	7.7	15.4
MISO	WL	WAUE_UGPM010003879_MEC	300	7-F	300	300	300	17.1	17.1	5.7
MISO	WL	WAUE_UGPM010003880_MEC	200	7-F	200	200	200	11.4	11.4	5.7
MISO	CPM	WEC_CWPC010004010_WPS	4	7-F	4	4	4	0.4	0.4	9.6
MISO	CPM	WEC_WPSM010001664_UPPC	65	7-F	65	65	65	3.8	3.8	5.9
TVA	WL	LES_APMM1JAN2910_AECI	40	7-F	40	40	40	2.6	2.6	6.6
TVA	WL	MEC_AECIJAN1011_AECI	4	7-F	4	4	4	0.2	0.2	6.0
TVA	WL	MEC_APMM1JAN2911_AECI	250	7-F	250	250	250	15.0	15.0	6.0
TVA	WL	MEC_MECBULET01003_AECI	150	7-F	150	150	150	9.0	9.0	6.0
		Total for 7-F	**1628**		**1628**	**1628**	**1628**	**63.5**	**63.5**	
		Global Total	**3759**		**3759**	**3759**	**3759**	**335.1**	**335.1**	

Eau Claire – Arpin Flow Gate Information:

The following IDC screen shot represents a NERC IDC "whole transaction" list with the proposed LMP market change order.

Sink SC	Method	Tag Name	Reservation MW	Reservation Priority	Reliability Cap	Market Cap	Actual MW	Amount on Flowgate Schedule	Amount on Flowgate Active	TDF (%)
EES	CPM	NewCo_TNSKDLJAN0278_EES	50	1-NS	50	50	50	3.6	3.6	7.1
PJM	CPM	NewCo_NSPPOW0092573_PJM	168	1-NS	168	168	168	33.0	33.0	19.7
		Total for 1-NS	**238**		**238**	**238**	**238**	**36.9**	**36.9**	
EES	WL	SECI_CRGL1ASH0107P_EES	25	2-NH	25	25	25	1.4	1.4	5.6
PJM	CPM	NewCo_AME010054962_PJM	50	2-NH	50	50	50	3.6	3.6	7.3
EES	CPM	NewCo_APMM1JAN3024_EES	50	2-NH	50	50	50	3.0	3.0	6.0
FPL	CPM	NewCo_NSPPOW0092750_FPL	105	2-NH	105	105	105	20.6	20.6	19.7
		Total for 2-NH	**230**		**230**	**230**	**230**	**28.6**	**28.6**	
PJM	CPM	NewCo_CNCTET0005785_PJM	53	3-ND	53	53	53	3.1	3.1	5.8
TVA	WL	SPC_TEA01TEO3010_AECI	60	3-ND	60	60	60	4.3	4.3	7.2
		Total for 3-ND	**113**		**113**	**113**	**113**	**7.4**	**7.4**	
MISO	CPM	NewCo LMP Market Economic Disp.		6-NN					79.3	
PJM	WL	PJM LMP Market Economic Disp.		6-NN					15.0	
EES	CPM	NewCo_APMM1JAN2912_EES	8	6-NN	8	8	8	0.5	0.5	6.0
		Total for 6-NN	**8**		**8**	**8**	**8**	**94.8**	**94.8**	
PJM	CPM	NewCo_CPS010101F00_PJM	30	7-F	30	30	30	2.2	2.2	7.3
PJM	CPM	NewCo_MECBULET01105_PJM	160	7-F	160	160	160	16.9	16.9	10.6
MISO	CPM	NewCo LMP Market NNL		7-F					120.0	
PJM	WL	PJM LMP Market NNL		7-F					16.0	
TVA	CPM	NewCo_APMM1JAN2910_AECI	40	7-F	40	40	40	2.6	2.6	6.6
TVA	CPM	NewCo_AECIJAN1011_AECI	4	7-F	4	4	4	0.2	0.2	6.0
TVA	CPM	NewCo_APMM1JAN2911_AECI	142	7-F	142	142	142	8.5	8.5	6.0
TVA	CPM	NewCo_MECBULET01003_AECI	17	7-F	17	17	17	1.0	1.0	6.0
		Total for 7-F	**993**		**993**	**993**	**993**	**167.4**	**167.4**	
		Global Total	**2461**		**2461**	**2461**	**2461**	**335.1**	**335.1**	

<u>Eau Claire – Arpin Flow Gate Information:</u>

<u>50MW of relief was required in this example. Only up to priority #3 was impacted.</u>

	SC Requestor:	MISO	**CA Requestor:**	ALTE		**TLR level:**	3B		
	Requested Relief:	50							
	IDC MW Curtailed:	432	**Trans. Curt.**	8		**Relief:**	50		
Sink SC	**Tag Name**	**Method**	**Tag Marginal Priority**	**Schedule MW**	**Active MW**	**Curtail MW**	**MW Cap**	**Status**	**Relief Provided**
EES	MEC_TNSKDLJAN0278_EES	WL	1-NS	50	50	50	0	CURTAIL	3.6
TVA	NSP_NSPPOW0092573_AECI	CPM	1-NS	168	168	168	0	CURTAIL	33.0
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
MAIN	MEC_AME010054962_AMRN	WL	2-NH	50	50	50	0	CURTAIL	3.6
SWPP	OPPD_CRGL1ABJ0108J_EDE	WL	2-NH	50	50	50	0	CURTAIL	2.8
TVA	MEC_SEINC0000500_AECI	WL	2-NH	50	50	50	0	CURTAIL	3.0
PJM	KCPL_CNCTET0005785_PJM	WL	3-ND	53	53	16	37	CURTAIL	0.9
TVA	NPPD_TEA01TEO3010_AECI	WL	3-ND	60	60	23	37	CURTAIL	1.7
									50.0
			Total Curtailment:	506	506	432	74		

******NOTE:** The curtailment report above (when only including transmission curtailment priorities of bucket 0 – 5) will not change with the NERC IDC LMP market change order proposal.

<u>Eau Claire – Arpin Flow Gate Information:</u>

<u>155MW of relief was required in the following example. Up to (and including) priority #6 was impacted.</u>

The following IDC screen shot represents a NERC IDC "curtailment" list as it works today.

SC Requestor:	MISO	CA Requestor:	ALTE	TLR level: 3B
Requested Relief:	155			
IDC MW Curtailed:	1208	Trans. Curt.	24	Relief: 155

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW Cap	Status	Relief Provided
EES	MEC_TNSKDLJAN0278_EES	WL	1-NS	50	50	50	0	CURTAIL	3.6
TVA	NSP_NSPPOW0092573_AECI	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
MAIN	MEC_AME010054962_AMRN	WL	2-NH	50	50	50	0	CURTAIL	3.6
TVA	MEC_SEINC0000500_AECI	WL	2-NH	50	50	50	0	CURTAIL	3.0
PJM	KCPL_CNCTET0005785_PJM	WL	3-ND	53	53	53	0	CURTAIL	3.1
TVA	NPPD_TEA01TEO3010_AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	ALTW_ALTMA10008672_ALTE	CPM	6-NN	78	78	78	0	CURTAIL	12.0
MISO	CE_ALTMA10008643_ALTE	CPM	6-NN	100	100	67	33	CURTAIL	4.3
MISO	CE_ALTMA10008651_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008652_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008653_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_ALTMA10008654_ALTE	CPM	6-NN	50	50	34	16	CURTAIL	2.2
MISO	CE_MSCG01MS39921_ALTE	CPM	6-NN	25	25	17	8	CURTAIL	1.1
MISO	CE_MSCG01MS39922_WEC	CPM	6-NN	25	25	17	8	CURTAIL	1.1
MISO	CE_WEPM24000813Q_WEC	CPM	6-NN	100	100	68	32	CURTAIL	4.4
MISO	MHEB_CRGL1AAA0107C_WEC	CPM	6-NN	100	100	100	0	CURTAIL	29.9
MISO	MPW_WEPM24000813X_WEC	CPM	6-NN	50	50	48	2	CURTAIL	5.5
MISO	MP_OTPW010007958_OTP	CPM	6-NN	50	50	29	21	CURTAIL	1.5
MISO	MP_OTPW010007975_OTP	CPM	6-NN	30	30	17	13	CURTAIL	0.9
MISO	NSP_WEPM24000813O_WEC	CPM	6-NN	100	100	50	0	CURTAIL	14.2
MISO	OTP_WEPM24000813J_WEC	CPM	6-NN	100	100	60	0	CURTAIL	12.7
MISO	WAUE_REMC010002261_WEC	CPM	6-NN	100	100	60	0	CURTAIL	13.2
TVA	MEC_APMM1JAN2912_AECI	WL	6-NN	8	8	5	3	CURTAIL	0.3
									156.
			Total Curtailment:	1522	1522	1208	184		

<u>Eau Claire – Arpin Flow Gate Information:</u>

<u>155MW of relief was required in this example. Up to (and including) priority #6 was impacted.</u>

The following IDC screen shot represents a NERC IDC "curtailment" list with the proposed LMP market change order.

SC Requestor:	MISO	CA Requestor:	ALTE	TLR level:	3B
Requested Relief:	155				
IDC MW Curtailed:	1338	Trans. Curt.	10	Relief:	155

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW Cap	Status	Relief Provided
EES	NewCo_TNSKDLJAN0278_EES	CPM	1-NS	50	50	50	0	CURTAIL	3.6
PJM	NewCo_NSPPOW0092573_PJM	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
PJM	NewCo_AME010054962_PJM	CPM	2-NH	50	50	50	0	CURTAIL	3.6
EES	NewCo_APMM1JAN3024_EES	CPM	2-NH	50	50	50	0	CURTAIL	3.0
FPL	NewCo_NSPPOW0092750_FPL	CPM	2-NH	105	105	105	0	CURTAIL	3.0
PJM	NewCo_CNCTET0005785_PJM	CPM	3-ND	53	53	53	0	CURTAIL	3.1
TVA	SPC_TEA01TEO3010_AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	NewCo LMP Market Economic Disp.	CPM	6-NN		80		0	Re-Dispatch	80.0
PJM	PJM LMP Market Economic Disp.	WL	6-NN		15		0	Re-Dispatch	15.0
EES	NewCo_APMM1JAN2912_EES	CPM	6-NN	50	50	50	0	CURTAIL	6.0
									156.0
			Total Curtailment:	611	706	1338			

FIRM CURTAILMENTS:
****NOTE: The curtailment report above represents the identical process used when curtailing firm (transmission priority #7). The exception of the above, is that a firm curtailment report will include and display the Control Areas located outside the LMP market that have an NNL reduction responsibility.

<u>Eau Claire – Arpin Flow Gate Information:</u>

<u>100MW of relief was required in this example. Up to priority #6 was impacted.</u>

The following IDC screen shot represents a NERC IDC "curtailment" list with the proposed LMP market change order.

SC Requestor:	MISO	CA Requestor:	ALTE	TLR level:	3B
Requested Relief:	100				
IDC MW Curtailed:	1338	Trans. Curt.	10	Relief:	100

Sink SC	Tag Name	Method	Tag Marginal Priority	Schedule MW	Active MW	Curtail MW	MW / FG-Impact Cap	Status	Relief Provided
EES	NewCo_TNSKDLJAN0278_EES	CPM	1-NS	50	50	50	0	CURTAIL	3.6
PJM	NewCo_NSPPOW0092573_PJM	CPM	1-NS	168	168	168	0	CURTAIL	33.1
EES	SECI_CRGL1ASH0107P_EES	WL	2-NH	25	25	25	0	CURTAIL	1.4
PJM	NewCo_AME010054962_PJM	CPM	2-NH	50	50	50	0	CURTAIL	3.6
EES	NewCo_APMM1JAN3024_EES	CPM	2-NH	50	50	50	0	CURTAIL	3.0
FPL	NewCo_NSPPOW0092750_FPL	CPM	2-NH	105	105	105	0	CURTAIL	3.0
PJM	NewCo_CNCTET0005785_PJM	CPM	3-ND	53	53	53	0	CURTAIL	3.1
TVA	SPC_TEA01TEO3010_AECI	WL	3-ND	60	60	60	0	CURTAIL	4.1
MISO	NewCo LMP Market Economic Disp.	CPM	6-NN		80		45	Re-Dispatch	35.0
PJM	PJM LMP Market Economic Disp.	WL	6-NN		15		8	Re-Dispatch	7.0
EES	NewCo_APMM1JAN2912_EES	CPM	6-NN	50	50	50	25	CURTAIL	3.0
									100.0
			Total Curtailment:	611	706	1338			

FIRM CURTAILMENTS:
****NOTE: The curtailment report above represents the identical process used when curtailing firm (transmission priority #7). The exception of the above, is that a firm curtailment report will include and display the Control Areas located outside the LMP market that have an NNL reduction responsibility.

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Appendix D – Implementation Schedule

Feb 2003-Mar 2004

- PJM & MISO continues to refine their respective models to include all Coordinated Flowgates
- PJM & MISO build processes to execute Whitepaper initiatives
- PJM & MISO implement Hold Harmless Rulings, as required

March – April 2004

- NERC Training Materials Distributed
- MISO and PJM conduct training, tests, and drills of the congestion management solutions
- MISO tests NNL calculations, PJM validates
- OATI Testing with MISO/PJM

May 2004

- PJM implements market expansion through ComEd
- PJM Congestion Management Solutions are implemented
- PJM/MISO Phase 1 of the JOA is implemented
- PJM/MISO improve processes when areas for improvement are identified (i.e., list of Coordinated Flowgates may grow)

Oct 2004

- PJM implements market expansion through AEP and DPL

Nov 2004

- PJM implements market expansion through Dominion VAP

Dec 2004

- MISO implements market throughout the MISO footprint
- PJM/MISO Phase 2 of the JOA is implemented

2005 and beyond

- As PJM's and MISO's markets grow – additional versions of the Reliability Plan will require approval and list of Coordinated Flowgates will change
- MISO and PJM improve processes for Market to Market Operations

Appendix E – PJM/MISO Examples and Case Studies

Summary

For these two examples the Historical and Two Days Prior Allocation was simulated for two Coordinated FGs. Third Party impacts were included along with current CBM and TRM values. The results were as follows:

FGs Studied:
6081 Quad Cities West
3241 Zion-Pleasant Prairie flo Wempletown-Paddock

Historical Allocation

FG #	MISO	PJM
6081	392	597
3241	873	288

Historical NNL %

FG #	MISO	PJM
6081	39.6%	61.4%
3241	75.4%	24.6%

Two Day Out Allocation

FG #	MISO	PJM
6081	448	681
3241	873	288

The rest of the write up will step through the examples and the Allocation process.

Step #1: Historical Allocation

Assume PJM consists of PJM Classic and CE only
Assume MISO Market consists of 30 “Day One” CAs

NNL will be calculated as each CA to its OWN load down to 0% in the From – To Direction.

Model : Current IDC Summer Base Case – no SDX Data. The appropriate MMWG case will be used for the actual Allocation that takes place.

Change Net Interchange such that it is zero for all participants (for both net export and import CAs per the process). The scaling will be done based on the MBASE of each unit in a CA

FG # 6081

TTC = 1400
TRM = 216
CBM = 0

FG Limit = TTC –TRM-CBM = 1184

NNL:

	MISO	PJM
>5%	89.9	219.5
<5%	114.65	16.35

FIRM Reservations:

	MISO	PJM
>5%	77.95	278.75
<5%	62.1	10

NNL +FIRM:

	MISO Final	PJM Final	Other Entities
>5%	167.85	498.25	195
<5%	176.75	26.35	N/A

The first step in the Allocation is to sum the >5% impacts for the FG. When this was done the FG came in allocated at 861.1 MW. This leaves additional room on the FG for 312.9MW before hitting the FG Limit of 1184MW.

The next step in the Allocation process is to start to allow the <5% impacts to be allocated up to the point of the FG Limit. In this case there is room for all <5% impacts to be added for each entity before the FG Limit is reached. With the addition of the <5% impacts the total Allocation on the FG becomes 1064.2. This indicates that there is room for additional Allocation of 119.8MW for PJM and MISO on the FG.

These remaining MW are allocated by using a pro-rata approach between the two reciprocating entities using the ratio of the Historical NNL values.

MISO Historical NNL= (MISO Historical >5% +MISO Historical <5%) =344.6 MW
PJM Historical NNL=(PJM Historical >5% +PJM Historical <5%)= 524.6 MW

MISO Historical Allocation % = 39.6%
PJM Historical Allocation %= 61.4%

MISO's additional FG Allocation = 47.4 MW
PJM's additional FG Allocation = 72.3 MW

Total Historical Allocation for FG 6081

MISO	PJM	Other Entities
392	597	195

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FG # 3421

Limit = 1195
TRM = 24
CBM = 0

FG Limit = TTC –TRM-CBM = 1171

NNL:

	MISO	PJM
>5%	117.6	0
<5%	107.38	12

FIRM Reservations:

	MISO	PJM
>5%	580.65	263.9
<5%	81.2	14

NNL +FIRM:

	MISO	PJM	Other Entities
>5%	698.25	263.9	10
<5%	188.55	26	N/A

The first step in the Allocation is to sum the >5% impacts for the FG. When this was done the FG came in allocated at 972.15 MW. This leaves additional room on the FG for 199 MW before hitting the FG Limit of 1171 MW.

The next step in the Allocation process is to start to allow the <5% impacts to be allocated up to the point of the FG Limit. In this case there is not room for all <5% impacts to be added for each entity before the FG Limit is reached.

These remaining <5% MW are allocated by using a pro-rata approach between the two reciprocating entities using the ratio of the <5% NNL values.

MISO <5% NNL= 188.5 MW
PJM <5% NNL = 26 MW

MISO <5% Allocation % = 87.9%
PJM <5% Allocation %= 12.1%

MISO's additional FG Allocation = 174.9 MW
PJM's additional FG Allocation = 24.1 MW

Total Historical Allocation for FG 3241

MISO	PJM	Other Entities
873	288	10

Historical Allocation

FG #	MISO	PJM
6081	392	597
3241	873	288

The reciprocal entity Historic NNL percentages are also recorded as these will be used in any subsequent Allocation for determining the amount of additional MWs to be assigned to each entity in the case there is room on the FG.

Historical NNL %

FG #	MISO	PJM
6081	39.6%	61.4%
3241	75.4%	24.6%

Step #2- Two Days Prior

The Reservation Piece was updated to include more up-to-date data. The updated reservations were estimated by grabbing an IDC Snapshot of all FIRM Tags that affect the FG by more than 0.1%.

The same Base Model as Historical Calculation was used with updated load forecast and topology from the SDX data for the study date. GLDF values were recalculated.

FG # 6081

TTC = 1400
TRM = 216
CBM = 0

FG Limit = TTC –TRM-CBM = 1184

NNL:

	MISO	PJM
>5%	189.41	242.01
<5%	55.44	13.83

FIRM Reservations:

	MISO	PJM
>5%	106.19	410.31
<5%	95.12	11.71

	MISO	PJM	Other Entities
>5%	295.60	652.32	55
<5%	150.56	25.54	0

The first step in the Allocation is to sum the >5% impacts for the FG. When this was done the FG came in allocated at 1002.92 This leaves additional room on the FG for 181.1 before hitting the FG Limit of 1184MW.

The next step in the Allocation process is to start to allow the <5% impacts to be allocated up to the point of the FG Limit. In this case there is room for all <5% impacts to be added for each entity before the FG Limit is reached. With the addition of the <5% impacts the total Allocation on the FG becomes 1179 his indicates that there is room for additional Allocation of 5MW for PJM and MISO on the FG.

To ensure that any previous additional Allocation is respected the amount of the Historical Allocation is compared to each entities current Allocation estimation. If the Historical Allocation is More Than the estimated current Allocation each entity is automatically allowed the amount of the previous Allocation. Otherwise the new estimated values are used.

Two Days Prior Estimated Allocation:

MISO = 446.16
PJM = 677.86

Historical Allocation:

MISO = 392
PJM = 597

Since the Historical Allocation is Less than the estimated Two Days Prior Allocation the remaining 5 MWs are allocated by using a pro-rata approach between the two reciprocating entities using the ratio of the Historical NNL values that was calculated above during the Historical Allocation.

MISO Historical Allocation = 39.6%
PJM Historical Allocation = 61.4%

MISO’s additional FG Allocation = 2 MW
PJM’s additional FG Allocation = 3 MW

Total Two Days Prior Allocation for FG 6081

MISO	PJM	Other Entities
448.16	680.86	55

FG # 3421

Limit = 1195
TRM = 24
CBM = 0

FG Limit = TTC –TRM-CBM = 1171

NNL:

	MISO	PJM
>5%	179.28	0
<5%	157.91	17.03

FIRM Reservations:

	MISO	PJM
>5%	674.1	265.4
<5%	77.85	18.45

	MISO	PJM	Other Entities
>5%	853	265.4	60
<5%	235	35.48	N/A

Since >5% impacts combined is Greater than FG Limit of 1171 the estimated Allocation will not have the addition of any <5% impacts included.

Two Days Prior Estimated Allocation:

MISO = 853
PJM = 265.4

To ensure that any previous additional Allocation is respected the amount of the Historical Allocation is compared to each entities current Allocation estimation. If the Historical Allocation is More Than the estimated current Allocation each entity is automatically allowed the amount of the previous Allocation. Otherwise the new estimated values are used.

Historical Allocation Values:

MISO = 873
PJM = 288

Since the Historical Allocation is More Than the estimated Two Days Prior Allocation the Reciprocal Entity Allocations are kept at this Historical level and those values are moved into the real time realm.

Two Day Out Allocation

FG #	MISO	PJM	
6081		448	681
3241	873	288	

The reciprocal entity Historic NNL percentages are also recorded as these will be used in any subsequent real time Allocation for determining the amount of additional MWs to be assigned to each entity in the case there is room on the FG.

Historical NNL %

FG #	MISO	PJM
6081	39.6%	61.4%
3241	75.4%	24.6%

Appendix F – List of Coordinated Flowgates

This appendix lists Coordinated Flowgates for the PJM and MISO RTOs. **Note that these lists are dynamic in nature, and may change over time as Flowgates' relevance increases or decreases.** PJM and MISO will post the most current version of this list on their OASIS to ensure stakeholders have access to the most current list at all times.

"Reciprocal with <RTO>" indicates that the Flowgate is also part of a Reciprocal Coordination agreement between PJM and the Midwest ISO, and Flowgate Allocations will occur on this Flowgate on a future-looking basis. All flowgates marked with an "x" are the flowgates that both MISO and PJM will mutually respect.

"Owner" indicates what entity will be considered the entity from whom the AFC calculations will be considered when performing Allocations.

"Manager" indicates which entity will be responsible for performing the Allocations.

Note that some Midwest ISO Coordinated Flowgates are marked "TBD" for Owner and Manager. As Midwest ISO will not be implementing the Congestion Management portions of this document at this time, it is unnecessary to define Owners and Managers for non-Reciprocal Coordinated Flowgates.

PJM Coordinated Flowgates

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	2007	AEP	05COOK 765 05COOK 345 1	AEP	PJM
x	2008	AEP	05DUMONT 765 05DUMTEQ 999 1	AEP	PJM
x	2014	AEP, CE	05OLIVE 345 UPNOR;RP 345 1	AEP	PJM
x	2015	AEP, CE	05OLIVE 345 G ACR; T 345 1	AEP	PJM
x	2017	AEP	05COOK 345 05OLIVE 345	AEP	PJM
x	2032	CIN, AEP	08CAYSUB 345 05EUGENE 345	MISO	MISO
x	2213	NIPS, CE	State Line-Wolf Lake 138 flo Dumont 765/345 Tr	MISO	MISO
x	2214	NIPS, CE	State Line-Wolf Lake 138 flo UP North-Olive 345	MISO	MISO
x	2215	NIPS, CE	State Line-Wolf Lake 138 flo SLINE;5S-WASHI; R 138	MISO	MISO
x	2221	NIPS, CE	Munster-Burnham 345 flo Olive-University Park North 345	MISO	MISO
x	2223	NIPS, AEP	Dumont-Stillwell 345 flo Olive-Green Acre 345	MISO	MISO

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	2286	CE, NIPS	Burnham-Munster 345 flo Dumont-Wilton Center 765	MISO	MISO
x	2287	CE, NIPS	Burnham-Munster 345 flo Dumont-Wilton Center 765 + Op Guide	MISO	MISO
x	2288	CE, NIPS	Burnham-Sheffield 345 flo Dumont-Wilton Center 765	MISO	MISO
x	2296	CE, NIPS	Munster-Burnham 345 flo University Park North-E. Frankfort 345	MISO	MISO
x	2298	AEP, NIPS	New Carlisle-Trail Creek 138 flo University Park North-E. Frankfort 345	MISO	MISO
x	2299	AEP	Dumont-Stillwell 345 flo Dumont-Wilton Center 765	AEP	PJM
x	2400	AEP	DUMONT765-345TX-COOK765-345TX	AEP	PJM
x	2401	CE, AEP	DUMONT765/345TX-DUMONT WILTON C 765	AEP	PJM
x	2402	AEP	COOK765-345TX-DUMONT765-345TX	AEP	PJM
x	2497	NIPS	State Line-Wolf Lake 138	MISO	MISO
x	2890	CE, NIPS	State Line-Wolf Lake 138 flo E. Frankfort-University Park North 345	MISO	MISO
x	2913	NIPS, AEP	Stillwell-Dumont 345	MISO	MISO
x	3001	CE, ALTE	WEMPLETOWN-PADDOCK 345 KV	MISO	MISO
x	3003	ALTE	COLUMBIA-S. FOND DU LAC 345 KV	MISO	MISO
x	3006	ALTE,NSP,WEC,WPS	EAU CLAIRE-ARPIN 345 KV	MISO	MISO
x	3009	NSP,ALTE,WEC,WPS	EAU CLAIRE-ARPIN+WEMPLETOWN-PADDOCK	MISO	MISO
x	3011	ALTE	PADDOCK 345/138 XFMR 1	MISO	MISO
x	3012	ALTE	PADDOCK XFMR 1 + PADDOCK-ROCKDALE	MISO	MISO
x	3018	ALTE,WPS,WEC,NSP	EAU CLAIRE-ARPIN+PRAIRIE ISLAND-BYRON	MISO	MISO
x	3021	ALTE	Paddock-Blackhawk 138 (flo) Paddock-Townline 138	MISO	MISO
x	3024	ALTE	Blackhwk-Colley Road 138 (flo) Paddock-Townline 138	MISO	MISO
x	3025	ALTE	Russel-Rockdale 138/Paddock-Rockdale 345	MISO	MISO
x	3034	ALTE	Blackhawk-ColleyRd xfmr FLO Paddock-Rockdale345	MISO	MISO
x	3038	ALTE	Paddock-Townline 138 (flo) Paddock-Blackhawk 138	MISO	MISO
x	3045	ALTE	Rockdale 345/138 Xfmr 3 flo Paddock 345/138 Xfmr	MISO	MISO
x	3059	CE, ALTE	Wempletown-Paddock 345 flo Arpin-Rocky Run 345 + Op Guide	MISO	MISO
x	3060	CE, ALTE	Wempletown-Paddock 345 flo King-Eau Claire-Arpin 345 + Op Guide	MISO	MISO
x	3063	ALTE	Paddock-Townline 138 (flo) Paddock-Rockdale 345	MISO	MISO
x	3107	AMRN	MONTGOMERY-SPENCER 345 KV	MISO	MISO
x	3112	AMRN, CILC	DUCK CREEK-IPAVA 345 kV	MISO	MISO

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3114	AMRN, AEP	BREED-CASEY 345 KV	MISO	MISO
x	3115	AMRN	COFFEEN-PANA 345 KV	MISO	MISO
x	3120	AMRN	COFFEEN-PANA+MONTGMRY-SPENCER	MISO	MISO
x	3123	AMRN	COFFEEN-PANA+DUMONT-WILTON CENTER	MISO	MISO
x	3127	AMRN	TAYLORVILLE-PAWNEE + COFFEEN-PANA-KINCAID	MISO	MISO
x	3131	AMRN	PAWNE-AUBURN+KINCAID-LATHM	MISO	MISO
x	3139	AMRN	PAWNEE WEST XFMR + PANA-KINCAID	MISO	MISO
x	3140	AMRN	MONTGMRY-SPENCER+COFFEEN-PANA-KINCAID	MISO	MISO
x	3142	AMRN	RAMSEY-PANA + COFFEEN-PANA-KINCAID	MISO	MISO
x	3145	AMRN	PANA XFMR + COFFEEN-COFFEEN NORTH	MISO	MISO
x	3159	AMRN	Neoga-Holland-Ramsey 345 Bland-Franks 345	MISO	MISO
x	3161	AMRN, CWLP	Auburn-Chatham 138 flo Latham-Kincaid 345	MISO	MISO
x	3201	CE, AEP	11215 DUMONT-WILTON 765KV(AEP-CE)	PJM	PJM
x	3202	CE	17723 BURNHAM-TAYLOR 345KV	PJM	PJM
x	3203	CE	10802 LOCKPORT-LISLE 345 KV RED	PJM	PJM
x	3204	CE	10801 LOCKPORT-LISLE 345 KV BLUE	PJM	PJM
x	3205	CE	16703 PLANO- ELECT JCT 345 KV RED	PJM	PJM
x	3206	CE	16704 PLANO-ELECT JCT 345 KV BLUE	PJM	PJM
x	3207	CE	TSS116 GOODINGS GR 345KV RED BUSTIE	PJM	PJM
x	3208	CE	0621 BYRON-CHERRY VALLEY 345KV BLUE	PJM	PJM
x	3209	CE	622 BYRON-CHERRY VALLEY 345KV RED	PJM	PJM
x	3210	CE	10802 Lock-LisR for 10801Lock-LiB+G	PJM	PJM
x	3211	CE	10801 Lock-LisB for 10802Lock-LiR+G	PJM	PJM
x	3212	CE	10802 Lock-Lisl R for 16703 PL-EJ R	PJM	PJM
x	3213	CE	10801 Lock-Lisl B for 16704 PL-EJ B	PJM	PJM
x	3214	CE	10322 Lis-LomR for 10321 Lis-LomB+G	PJM	PJM
x	3215	CE	10321 Lis-LomB for 10322 Lis-LomR+G	PJM	PJM
x	3216	CE	0621 Byron-ChV B for 0622 Byr-ChV R	PJM	PJM
x	3217	CE	0621 Byron-ChV B for 0624 Byr-Wemp	PJM	PJM
x	3218	CE	0622 Byron-ChV R for 0621 Byr-ChV B	PJM	PJM

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3219	CE	0622 Byr-ChV Red for 0624 Byr-Wemp	PJM	PJM
x	3220	CE	16704 Plan-EJ B for 16703 Plan-EJ R	PJM	PJM
x	3221	CE	16703 Plan-EJ Red for 16704 Pl-EJ B	PJM	PJM
x	3222	CE	11601 EFrk-GoodiB for 11602 EF-GG R	PJM	PJM
x	3223	CE	11602 EFrk-GoodiR for 11601 EF-GG B	PJM	PJM
x	3227	CE	0404 Quad-H471 for 15503 Cordo-Nelson	PJM	PJM
x	3228	CE	0403 Quad-Cord-Nelson for 0404 Quad-H471	PJM	PJM
x	3229	CE	11604 Goodi-LockR for 11617GG-LockB	PJM	PJM
x	3230	CE	11617 Goodi-LockB for 11604GG-LockR	PJM	PJM
x	3231	CE	GOODI 345R BT for 1223Dres-EJ B+T83	PJM	PJM
x	3232	CE	11120 EJ-W407 for 10802 Lock-LiR +G	PJM	PJM
x	3233	CE	11124 EJ-Lomb for 10801 Lock-LiB +G	PJM	PJM
x	3234	CE	2102 Kincaid-Lath for 11215 Dum-Wlt	PJM	PJM
x	3235	CE	2101 Kinc-BrokTp for 11215 Dum-Wilt	PJM	PJM
x	3236	CE, ALTE	17101 Wemp-Pad for 9922 Zion-Arcad	MISO	MISO
x	3237	CE, ALTE	17101 Wemp-Pad for 2221 Zion-PlsPr	MISO	MISO
x	3238	CE, ALTE	17101 Wemp-Pad for 15616 ChV-Silver	MISO	MISO
x	3239	CE, ALTE	17101 Wemp-Pad for Arpin-ÉauClar +G	MISO	MISO
x	3240	CE, WEC	2221 Zion-PlsPr for 9922 Zion-Arcd	PJM	PJM
x	3241	CE, WEC	2221 Zion-PlsP for 17101 Wemp-Pad	PJM	PJM
x	3242	CE, WEC	9922 Zion-Arcad for 2221 Zion-PlsP	PJM	PJM
x	3244	CE	Nels Tr84 for 15502 Nels-EJ +Tr82	PJM	PJM
x	3245	CE	15616 Cher-Silv for 15502 Nels-EJ	PJM	PJM
	3246	CE	4525 Jef-KingsR for 10802Lock-Li R+G	PJM	PJM
	3247	CE	4527 Jef-KingsB for 10801 Lock-LiB+G	PJM	PJM
x	3248	CE	12204 Bel-Mar R for 15616 ChV-Silvr	PJM	PJM
x	3249	CE	12205 Bel-Mar B for 15616 ChV-Silvr	PJM	PJM
x	3250	CE	15502 Nels-EJ for 15616 Cher-Silv	PJM	PJM
x	3251	CE	0404 Quad Cities – NWS&W (H471)	PJM	PJM
x	3252	CE	11622 Elwd-GG R 345 for 1223 Dres-EJ R + Dres Tr 81	PJM	PJM

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3253	CE	Kewanee(CE)-Kewanee(IP) 138 BT	PJM	PJM
x	3254	CE	Pwr JctB-Powerton 138	PJM	PJM
x	3257	CE, MEC	Quad City-SUB 91 345 KV	PJM	PJM
x	3258	CE, ALTW, MEC	Quad City-Rock Creek (FLO) QC-SUB91	PJM	PJM
x	3259	CE, MEC	Quad-SUB 91 345 for MEC Cordova-SUB 39(Moline) 345kV	PJM	PJM
x	3260	CE	15501 Lee Co-Nelson 345 for 17101 Wemp-Pad 345	PJM	PJM
x	3261	CE	L8012 Pontiac-Wiltn345 for L8014 Pont-Dresd345	PJM	PJM
x	3262	CE	Nelson 345-138 T82 for Nelson 345-138 T84	PJM	PJM
x	3263	CE	Nelson-Dixon B FLO Nelson-Nelson RT	PJM	PJM
x	3264	CE	Nelson-Nelson RT FLO Nelson-Dixon B	PJM	PJM
x	3265	CE	OTDF ChV-Bel Red FLO ChV-SilvLk	PJM	PJM
x	3266	CE, ALTW	Garden Plain-Albany 138 flo Quad Cities-H471 345	PJM	PJM
x	3267	NIPS, CE	Munster-Burnham 345 flo Dumont-Wilton Center 765 + Op Guide	MISO	MISO
x	3268	NIPS, CE	Munster-Burnham 345 flo Dumont-Wilton Center 765	MISO	MISO
x	3269	NIPS, CE	Sheffield-Burnham 345 flo Dumont-Wilton Center 765	MISO	MISO
x	3270	CE, NIPS	State Line-Wolf Lake 138 flo Burnham-Sheffield 345	MISO	MISO
x	3271	CE, NIPS	State Line-Wolf Lake 138 flo Wilton Center-Dumont 765	MISO	MISO
x	3301	CILC	TAZEWELL – MASON 138 KV	MISO	MISO
x	3302	CILC	East Springfield-Holland 138 KV	MISO	MISO
x	3303	CILC, CWLP	E SPRINGFIELD-EASTDALE 138 KV	MISO	MISO
x	3304	CILC, CE	POWERTON-TAZEWELL 345 KV	MISO	MISO
x	3306	CILC	Holland-Mason138+Duck Creek-Tazewell345	MISO	MISO
x	3310	CE, CILC	Powerton-Tazewell 345 flo Powerton-Goodings Gr. 345 B	MISO	MISO
x	3311	CE, CILC	Powerton-Tazewell 345 flo Powerton-Goodings Gr. 345 R	MISO	MISO
x	3401	IP	SIDNEY XFMR + BUNSONVILLE XFMR	MISO	MISO
x	3405	IP, AEP	BUNSONVILLE-EUGENE + BREED-CASEY	MISO	MISO
x	3408	IP	PANA-MOWEAQ T + KINCAID-LATHAM	MISO	MISO
x	3410	IP	SIDNEY XFMR + DUMONT-WILTON	MISO	MISO
x	3413	AMRN, IP	COFFN-ROXFD IP FOR XENIA-MT VRNON	MISO	MISO
x	3414	AMRN, IP	COFFN-ROXFD IP FOR COFFN-COFFN N	MISO	MISO

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3416	IP	COFFEEN-ROXFORD 345	MISO	MISO
x	3418	IP	COFFEEN-ROXFORD 345 FOR LOSS OF BAKER-BROADFORD 765	MISO	MISO
x	3419	IP,AMRN	Xenia-MtVernon 345 for Coffeen-Roxfd 345	MISO	MISO
x	3420	IP	Coffeen-Roxford Rockport-Jefferson	MISO	MISO
x	3503	WEC	ALBERS-PARIS 138 KV	MISO	MISO
x	3507	ALTE,WEC	EDGEWATER-Cedarsauk-Granville 345 KV	MISO	MISO
x	3517	WEC	ARCADIAN-GRANVILE 345 KV	MISO	MISO
x	3527	WEC	PleasPr-Racine 345 for Wemp-Pad 345	MISO	MISO
x	3529	WEC,WPS	N. Appleton-Rocky Run 345kV	MISO	MISO
x	3534	WEC	Kenosha-Albers 138 for Wempletown-Paddock 345	MISO	MISO
x	3537	WEC	Kenosha-Lakeview 138 for PleasPr-Zion 345	MISO	MISO
x	3557	WEC	PleasPrairie-Arcadian138 FLO PleasPrairie-Racine345	MISO	MISO
x	3558	WEC	PleasPrairie-Arcadian345 FLO Zion-Arcanian345	MISO	MISO
x	3560	WEC	Whitewater-Mukwonago FLO CherryVal-SilvrLk345	MISO	MISO
x	3570	WEC, CE	Pleasant Prairie-Zion 345 flo Cherry Valley-Silver Lake 345 R	PJM	PJM
x	3571	WEC, CE	Pleasant Prairie-Zion 345 flo Zion-Arcadian 345	PJM	PJM
x	3572	WEC, CE	Pleasant Prairie-Zion 345 flo Zion-Arcadian 345 + Op Guide	PJM	PJM
x	3601	ALTE,WPS	ARPIN – ROCKY RUN 345 KV	MISO	MISO
x	3602	WPS,WEC	ROCKY RUN – N APPLETON 345 KV	MISO	MISO
x	3604	WPS,ALTE	N FOND DU LAC-AVIATION 138 KV	MISO	MISO
x	3705	ALTW	Arnold-Hazelton 345 for Wemp-Paddock 345	MISO	MISO
x	3706	ALTW	Arnold – Hazleton	MISO	MISO
x	3711	ALTW	Albany 161-138 for Nelson-Cordo B 345	MISO	MISO
x	3715	ALTW, CE	Quad Cities-Rock Creek 345/MEC Cordova-Sub 39	PJM	PJM
x	3716	ALTW	Rock Creek 345/161 TR for Quad-Sub 91 345	MISO	MISO
x	3719	ALTW	Salem 345/161 Quad Cities-Sub 91	MISO	MISO
x	3720	ALTW	Salem 345/161 TR for MEC Cordova-Sub 39 345kV	MISO	MISO
x	3721	ALTW	Salem 345/161 for Quad-Sub 91 TR	MISO	MISO
x	3723	ALTW	Tiffon-D.Arnold 345 for Hills-Montezuma 345kV	MISO	MISO
x	3732	ALTW	Arnold-Hazelton 345 (flo) Dorsey-Forbes 500	MISO	MISO

Reciprocal with MISO	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3736	ALTW	Salem 345/161 flo Wempletown-Paddock 345	MISO	MISO
x	3740	ALTW,CE	Albany-Garden Plain 138 flo Quad Cities-H471 345	PJM	PJM
x	3749	ALTW	Arnold-Hazelton 345 (flo) Montezuma-Bondurant 345	MISO	MISO
x	6009	NPPD, MPS, AECI, OPPD	COOPER_S	MAPP	MISO
x	6074	MEC	Sub 91 345/161kV XFMR FLO Sub 91-Sub 56 345kV	MAPP	MISO
x	6081	MEC	Quad City West 345kV	MAPP	MISO
x	6084	MEC	East Moline 345/161 XFMER (flo) Quad Citites – Sub 91	MAPP	MISO
x	6086	MEC	Montezuma-Bondurant 345kV	MAPP	MISO
x	6088	DPC,NSP	Genoa-Seneca (flo) Eau Claire-Arpin	MAPP	MISO
x	6105	ALTW, CE	Quad Cities – Rock Creek	PJM	PJM
x	6117	MEC	Sub 92-Hills flo Sub 93-Sub T-Hills	MAPP	MISO
x	6124	MEC,ALTW	Sub K/Tiffin-Arnold 345kV	MAPP	MISO
x	6136	CE, MEC	Quad Cities-Sub 91 345 flo Quad Cities-Rock Creek 345	PJM	PJM

MISO Coordinated Flowgates

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	12	PJM,NYIS	Warren-Falconer 115 kV line	TBD	TBD
	13	PJM,NYIS	Erie East-South Ripley 230 kV line	TBD	TBD
	18	PJM,NYIS	Homer City-Watercure Road 345 kV l	TBD	TBD
	20	PJM	Erie West-Erie South 345 kV line	TBD	TBD
	21	PJM	Erie West 345/115 kV xfmr l/o Erie West-Erie South 345 kV	TBD	TBD
	22	PJM	Erie West-Erie South 345 kV l/o Ho 318.1	TBD	TBD
	100	PJM	Kammer #8 xfmr l/o Belmont-Harrison 500	TBD	TBD
	101	PJM,AEP	Kammer #8 xfmr l/o Kammer-South Canton 765 kV line	TBD	TBD
	110	PJM	Wylie Ridge #7 tx l/o Wylie #5 tx (WK3 CB open – OP Proc.)	TBD	TBD
	111	PJM,FE	Sammis-Wylie Ridge 345 kV line l/o Perry-Ashtabula-Erie West	TBD	TBD
	112	PJM,FE	Sammis-Wylie Ridge 345 kV line l/o Belmont-Harrison 500 kV	TBD	TBD
	200	AEP	Tidd-Canton Central 345 kV line l/o Kammer-South Canton 765	TBD	TBD
	205	AEP,FE	Sammis-South Canton 345 kV line l/o Tidd-Canton Central 345	TBD	TBD
	1001	AECI,AMRN	FptLatlatStr	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	1002	AECI,AMRN	ThmMobThoMcc	TBD	TBD
	1003	AECI,AMRN	ThmMobThmSal	TBD	TBD
	1004	AECI,AMRN	MccTieAECAMRN	TBD	TBD
	1005	AECI,AMRN	MarXfrBlaFra	TBD	TBD
	1010	AECI,AMRN	MccTieAMRN AEC	TBD	TBD
	1011	AMRN,AECI	PalXfrPalSub	TBD	TBD
	1014	AECI,AMRN	Lutsvle-Essx-NMadrid for loss of Bland Franks	TBD	TBD
	1015	AECI	Fairport-Lathrop for the loss of StJoe-Hawthorne(LakeRd-Nashua)	TBD	TBD
	1016	AECI	Lutesville-Essex for the loss of Wilhelmina-NewMadrid &	TBD	TBD
	1017	EES,AECI,AMRN	NewMadrid-Dell for loss of Shelby-Lagoon Creek	TBD	TBD
	1018	EES,AECI,AMRN	NewMadrid-Dell for loss of Ises-Dell	TBD	TBD
	1019	EES,AECI,AMRN	NewMadrid-Dell for loss of Tiptonville	TBD	TBD
	1020	AECI	New Madrid 345/500 #1 for Loss of MarshallCumberland500	TBD	TBD
	1021	AECI	New Madrid 345/500 #1 for Loss of Shelby-LagoonCrk500	TBD	TBD
	1201	SOCO,DUK,SC,SCEG	VACAR-SOUTHERN	TBD	TBD
	1203	DUK,AEP	8ANTIOCH 500 05J.FERR 500	TBD	TBD
	1205	DUK,SOCO	8OCONEE 500 8NORCROS 500	TBD	TBD
	1318	EES,OKGE	RusselvilleS-DardanelleDam for los	TBD	TBD
	1320	EES,OKGE	ANO-FtSmith for loss of ANO500-161	TBD	TBD
	1321	EES,OKGE	ANO-FtSmith for loss of Pleasant Hill-ANO	TBD	TBD
	1340	EES	Sheridan-WhiteBluff for loss of Ma	TBD	TBD
	1351	EES,AECI	NewMadrid-Dell	TBD	TBD
	1352	EES	ISES-Dell	TBD	TBD
	1354	EES	RayBraswell-Lakeover	TBD	TBD
	1358	EES	McAdams-LakeOver	TBD	TBD
	1365	EES	West Memphis – Birmingham Steel for the loss of Dell – Shelby	TBD	TBD
	1366	EES,AECI,AMRN	NewMadrid-Dell for loss of Marshall-Cumberland	TBD	TBD
	1367	EES,AECI,AMRN	NewMadrid-Dell for loss of Shawnee-Marshall	TBD	TBD
	1377	AECI,AMRN	Fairport-Lathrop for loss of Iatan-Stranger (LakeRoad-Nashua OpGuide)	TBD	TBD
	1382	EES	Hayti – Blytheville for the loss o	TBD	TBD
	1385	EES	Webre Richard for the loss of Perr	TBD	TBD
	1397	EES	Dell – Shelby for the loss of West Memphis – Birmingham	TBD	TBD
	1501	SOCO,TVA	Conasaga – Sequoyah 500	TBD	TBD
	1504	SOCO,TVA	Miller500-Bellefonte#2&MillerLowndes	TBD	TBD
	1505	SOCO,TVA	Miller-Lowndes500&Daniel-McKnight	TBD	TBD
	1510	SOCO,DUK	8NORCROS 500 80CONEE 500 1	TBD	TBD
	1544	SOCO	Lexington-Russell flo Norcross-Oco	TBD	TBD
	1605	TVA	Shawnee – Clinton 161	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	1609	TVA	Shawnee – C37A 161	TBD	TBD
	1611	TVA	Shawnee – Coleman 161	TBD	TBD
	1612	TVA	Shawnee 161/500 Transformer	TBD	TBD
	1613	TVA	Volunteer – Phipps Bend 500	TBD	TBD
	1615	TVA	Shawnee-Clinton161&Shawnee161/500t	TBD	TBD
	1616	TVA	Shawnee-C31161&Joppa-CapeGireadu161	TBD	TBD
	1617	TVA,SOCO	SNP-Consauga&Oconee-Norcross	TBD	TBD
	1620	TVA	Cumbland-Davidson&Cumbland-Jvill	TBD	TBD
	1621	TVA	Cumbland-Jvill&Cumbland-Davidson	TBD	TBD
	1622	TVA,LGEE	Paddys Run-Summershade 161 (flo) Broadford-Sullivan 500	TBD	TBD
	1623	TVA,LGEE	Paddys Run-Summershade 161 (flo) Paradise-Montgomery 500 kV	TBD	TBD
	1627	TVA,EKPC	Wolf Crk-Russell&PhippsBnd-Pocket	TBD	TBD
	1631	TVA,LGEE	Pinevil-Pinevil&PhippsBnd-Pocket	TBD	TBD
	1632	TVA,LGEE	Pinevil-Pinevil&Volunteer 500/161	TBD	TBD
	1634	TVA	Volunteer-Bull Run&WBN-Volunteer	TBD	TBD
	1635	TVA	Marshall Bank	TBD	TBD
	1638	TVA,EES	Shelby-Dell 500-kV	TBD	TBD
	1639	TVA,LGEE	Kentucky-Livingston 161-kV	TBD	TBD
	1640	TVA,LGEE	Calvert-Livingston 161-kV	TBD	TBD
	1641	TVA	Volunteer-PhippsBend 500 for Loss of Volunteer 500/161	TBD	TBD
	1642	BREC	Henderson138/161 flo Culley-Grandview138	TBD	TBD
	1643	TVA	Volunteer500/161 FLO VolunteerPhippsBend 500	TBD	TBD
	1644	TVA	Bull Run – Volunteer 500kV	TBD	TBD
	1701	PJM,VAP	01PRNTY 500 8MT STM 500	TBD	TBD
	1706	VAP,AEP	CLOVERDALE-LEXINGTON 500	TBD	TBD
	1707	CPLE,VAP	WAKE-CARSON 500	TBD	TBD
	1722	VAP	Clover 230-500 Trans./Wake-Carson	TBD	TBD
	2004	AEP	05MARYSV 765 05MARYSV 345 1	TBD	TBD
	2005	AEP	05MARYSV 05E LIMA 345-MARYSV SWLIMA 345	TBD	TBD
	2006	AEP	05SCANTO 765 05SCANTO 345 1	TBD	TBD
x	2007	AEP	05COOK 765 05COOK 345 1	AEP	PJM
x	2008	AEP	05DUMONT 765 05DUMTEQ 999 1	AEP	PJM
	2009	AEP	05COOK 345 05BENTON 345 1	TBD	TBD
	2010	AEP,MECS	05COOK 345 18PALISA 345 1	TBD	TBD
	2011	AEP,MECS	05ROB PK 345 18ARGENT 345 1 -147.2	TBD	TBD
	2012	AEP,MECS	05TWIN B 345 18ARGENT 345 1	TBD	TBD
x	2014	AEP,CE	05OLIVE 345 UPNOR;RP 345 1	AEP	PJM
x	2015	AEP,CE	05OLIVE 345 G ACR; T 345 1	AEP	PJM
	2016	AEP	05FALL C 345 05DESOTO 345 1	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	2017	AEP	05COOK 345 05OLIVE 345	AEP	PJM
	2018	AEP	05DARWIN 345 05EUGENE 345 1	TBD	TBD
	2019	AEP	05BREED 345 05DEQUIN 345 1	TBD	TBD
	2020	OVEC,AEP	06KYGER 345 05SPORN 345 1	TBD	TBD
	2021	HE,CIN	07MEROM5 345 08DRESSR 345 1	TBD	TBD
	2022	HE,CIN	08GIBSON 345 07MEROM5 345 1	TBD	TBD
	2023	HE,CIN	07BLOMNG 345 08BLOOM 230 1	TBD	TBD
	2024	HE,SIGE	07NWTNVL 161 10NEWTVL 161	TBD	TBD
	2025	HE,IPL	Ratts-Petersburg 138	TBD	TBD
	2026	SIGE,BREC	10NEWTVL 161 14COLE 5 161	TBD	TBD
	2029	CIN,AEP	08HNTNGT 138 05HUNT J 138 1	TBD	TBD
	2030	CIN,AEP	08NOBLSV 345 05FALL C 345 1	TBD	TBD
	2031	CIN,AEP	Dequine-Westwood 345 flo Cayuga-Ve	TBD	TBD
x	2032	CIN, AEP	Cayuga-Eugene 345 (flo) Cayuga-Nucor 345	MISO	MISO
	2033	CIN, AEP	New Castle-Fall Creek 138 (flo) Fall Creek 345/138 XFMR	TBD	TBD
	2034	AEP,CIN	Greentown 765/230/138 Xfm flo Greentown-Dumont 765	TBD	TBD
	2035	AEP,CIN	05GRNTWN 765 08GRNTWN 138 1	TBD	TBD
	2037	AEP,CIN	05STANNER 345 08M.FTHS 345 1	TBD	TBD
	2038	AMRN,CIN	LAWRNCVL 138 08VIN 138 1	TBD	TBD
	2040	DPL,CIN	09STUART 345 08FOSTER 345 1	TBD	TBD
	2041	DPL,CIN	Foster-Sugar Creek 345	TBD	TBD
	2042	HE,CIN	07NAPOL8 138 08BATESV 138 1	TBD	TBD
	2043	HE,CIN	07WORTH8 138 08HEOWEN 138	TBD	TBD
	2044	IPL,CIN	16PETE 138 08OKLND 138	TBD	TBD
	2045	IPL,CIN	16PETE 138 08VIN J 138 1	TBD	TBD
	2046	IPL,CIN	Petersburg-Lost River 345 flo Gibson-Bedford 345	TBD	TBD
	2047	IPL,CIN	Gibson-Petersburg 345 flo Gibson-Bedford 345	TBD	TBD
	2048	IPL,CIN	16SUNNYS 345 08GWYNN 345 1	TBD	TBD
	2049	LGEE,CIN	12GHENT 345 08BATESV 345 1	TBD	TBD
	2050	LGEE,CIN	08SPEED 345 12GHENT 345 1	TBD	TBD
	2051	LGEE,CIN	11JEFFJC 138 08JEFF 138 1	TBD	TBD
	2052	LGEE,CIN	Speed-Northside 138 flo Speed-Ghent 345	TBD	TBD
	2053	LGEE,CIN	Gallagher-Paddys West 138 flo Rock 114.5	TBD	TBD
	2055	OVEC,CIN	Pierce-Foster 345 flo Stuart-Foster 345	TBD	TBD
	2056	CIN,AMRN	08GIBSON 345 ALBION 345 1	TBD	TBD
	2057	CIN,DPL	Miami Fort-West Milton 345 flo Foster-Sugarcreek 345	TBD	TBD
	2059	CIN,EKPC	08BUFTN1 138 20BOONE 138 1	TBD	TBD
	2060	CIN,HE	08BLOOM 230 07BLOMNG 345 1	TBD	TBD
	2061	CIN,HE	08LINTON 138 07WORTH8 138 1	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2062	CIN,IPL	085PTBK1 138 16FVE_T 138 1 40.8	TBD	TBD
	2063	CIN,IPL	Whitestown-Guion 345 (flo) Whitestown-Hortonville 345	TBD	TBD
	2064	CIN,LGEE	11GHENT 138 08FAIRW 138 1	TBD	TBD
	2068	CIN,OVEC	06PIERCE 345 08BKJ135 138 1	TBD	TBD
	2069	CIN,OVEC	08BUFTN1 345 06DEARB2 345 1	TBD	TBD
	2070	CIN,OVEC	08BUFTN1 345 06PIERCE 345 1	TBD	TBD
	2071	CIN,SIGE	08OKLND 138 10TOYOTA 138 1 125.4	TBD	TBD
	2072	CIN	New London-Webster 230 flo Jefferson-Greentown 765	TBD	TBD
	2073	CIN,DPL	Foster-Sugar Creek 345 (flo) Stuart-Clinton 345	TBD	TBD
	2074	DPL	09STUART 345 09CLINTO 345 1	TBD	TBD
	2077	SIGE,BREC	10ABBRWW 138 14HENDR4 138 1	TBD	TBD
	2078	SIGE,IPL	Cato-Petersburg 138	TBD	TBD
	2079	SIGE,CIN	10TOYOTA 138 08OKLND 138 1 -125.4	TBD	TBD
	2083	SIGE	Culley-Grandview 138	TBD	TBD
	2084	SIGE	Northeast-Elliot 138	TBD	TBD
	2085	SIGE	Culley-Grimm 138	TBD	TBD
	2086	SIGE	10NEWTVL 161 10NEWTVL 138 1	TBD	TBD
	2087	SIGE	A.B. Brown-Northeast 138	TBD	TBD
	2088	SIGE	Culley-Dubois 138	TBD	TBD
	2089	OVEC,LGEE	06CLIFTY 345 11TRIMBL 345 1	TBD	TBD
	2092	LGEE	11CLVRPR 138 12G R ST 138 1	TBD	TBD
	2093	LGEE	11CLVRPR 138 12HARDBG 138 1	TBD	TBD
	2095	LGEE,BREC	11CLVRPR 138 14N.HAR4 138 1	TBD	TBD
	2096	LGEE,EKPC	Blue Lick-Bullitt County 161 (flo) Trimble-Clifty Creek 345	TBD	TBD
	2097	LGEE,TVA	11PADDYS 161 5SUMMER 161 1	TBD	TBD
	2100	BREC	14COLE 5 161 14NATAL5 161 1	TBD	TBD
	2101	BREC	14REID 5 161 14DAVIS5 161 1	TBD	TBD
	2102	BREC,TVA	14HOPCO5 161 5BARKLEY 161 1	TBD	TBD
	2103	IPL	16PETE 345 16THOMPS 345 1	TBD	TBD
	2104	IPL	16PETE 345 16FRANCS 345 1	TBD	TBD
	2105	IPL,AEP	16WHEAT 345 05BREED 345	TBD	TBD
	2106	IPL,AEP	16SUNNYS 345 05FALL C 345 1	TBD	TBD
	2107	IPL,AEP	Tanners Creek-Hanna 345 kV	TBD	TBD
	2131	PJM,FE	Sammis-Wylie Ridge 345	TBD	TBD
	2132	PJM,FE	KRENDALE-SENECA 138 FLO CABOT-WYLIE RIDGE 500	TBD	TBD
	2133	PJM,AEP	01BELMNT 500 05BELMON 765 1	TBD	TBD
	2134	PJM,AEP	Wylie Ridge-Tidd 345 kV line	TBD	TBD
	2135	PJM,AEP	01KAMMER 500 05KAMMER 765 1	TBD	TBD
	2137	PJM,DLCO	01MITCHL 138 15ELRM 3 138 1	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2141	FE,DLCO	02SAMMIS 345 15BVRVAL 345 1	TBD	TBD
	2184	FE,MECS	Bay Shore-Monroe 345 flo Lemoyne-Majestic 345	TBD	TBD
	2185	FE,MECS	LEMOYNE-MAJESTIC 345 flo BAY SHORE-MONROE 345	TBD	TBD
	2186	FE,MECS	Allen-Lulu 345	TBD	TBD
	2187	LGEE	12W LEXI 345 12W LEXI 138 1	TBD	TBD
	2188	LGEE	12W LEXI 345 12BRWN N 345 1	TBD	TBD
	2189	LGEE	12BRWN N 345 12BRWN N 138 1	TBD	TBD
	2190	LGEE	12BRWN N 345 12ALCALD 345 1	TBD	TBD
	2191	LGEE	12ALCALD 345 12ALCALD 161 1	TBD	TBD
	2192	LGEE	Pineville 500/345 Tr. 138	TBD	TBD
	2193	LGEE,TVA	12POCKET 500 8PHIPP B 500 1	TBD	TBD
	2194	BREC	14N.HAR4 138 14N.HAR5 161	TBD	TBD
	2195	AEP,DPL	CENTRAL OHIO	TBD	TBD
	2196	LGEE	Blue Lick 345/161 XFMR	TBD	TBD
	2197	OVEC,AEP	Kyger-Sporn345 for Amos 765/345XFMR	TBD	TBD
	2198	LGEE	Blue Lick 345/161 XFMR-Baker-Broadford	TBD	TBD
	2199	LGEE	Ghent-W.Lexington 345kV-Baker-Broadford	TBD	TBD
	2200	LGEE	Brown-Lebanon 138 kV	TBD	TBD
	2201	LGEE	Brown South-Fawkes 138 kV	TBD	TBD
	2202	OVEC,AEP	Kyger-Sporn345 for Baker-Broadford 765	TBD	TBD
	2203	CIN	BUFFINGTON_345_138_PIERCE_FOSTER_345	TBD	TBD
	2209	LGEE	W.Lex-E.W.Brown345 / Baker-Broadford765kv	TBD	TBD
	2210	LGEE	Knob Creek-Pond Creek 138 flo Baker-Broadord 765	TBD	TBD
x	2213	NIPS,CE	State Line-Wolf Lake 138 flo Dumont 765/345 Tr	MISO	MISO
x	2214	NIPS,CE	State Line-Wolf Lake 138 flo UP North-Olive 345	MISO	MISO
x	2215	NIPS,CE	State Line-Wolf Lake 138 flo SLINE;5S-WASHI; R 138	MISO	MISO
	2216	NIPS,AEP	New Carlisle-Trail Creek 138 flo Olive-Green Acre 345	TBD	TBD
	2217	NIPS,AEP	New Carlisle-Trail Creek 138 flo Olive-UPNOR:RP 345	TBD	TBD
	2218	NIPS,AEP	New Carlisle-Trail Creek 138 flo D	TBD	TBD
	2220	NIPS,AEP	New Carlisle-Maple 138 flo Dumont-	TBD	TBD
x	2221	NIPS,CE	Munster-Burnham 345 flo Olive-University Park North 345	MISO	MISO
	2222	NIPS,AEP	Kline-Northeast 138 flo Olive-Gree	TBD	TBD
x	2223	NIPS,AEP	Dumont-Stillwell 345 flo Olive-Green Acre 345	MISO	MISO
	2225	NIPS,CIN	Deedsville-Leesburg 345 flo Dumont 345/138 Tr	TBD	TBD
	2228	NIPS	Hiple 345/138 Tr flo Goshen Jct-Hi 217.3	TBD	TBD
	2230	NIPS	East Winamac-Burr Oak 138 flo Oliv	TBD	TBD
	2231	NIPS,AEP	Laporte-Michigan City 138 flo Dumont-Stillwell 345	TBD	TBD
	2232	NIPS	Michigan City-Trail Creek 138 flo Olive-Green Acre 345	TBD	TBD
	2233	NIPS	Michigan City-Trail Creek 138 flo Dumont-Stillwell 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2234	NIPS	Monticello-East Winamac 138 flo Du	TBD	TBD
	2236	FE,MECS	ALLEN-LULU 345 flo BAY SHORE-MONROE 345	TBD	TBD
	2237	FE	BAY SHORE-TOUSSAINT 138 flo DAVIS BESSE-BEAVER 345	TBD	TBD
	2238	FE	GREENFIELD-LAKEVIEW 138 flo BEAVER-DAVIS BESSE 345	TBD	TBD
	2239	FE,AEP	LEMOYNE-FOSTORIA 345 flo BAY SHORE-FOSTORIA 345	TBD	TBD
	2240	FE	Toussaint-Ottawa 138 flo Davis Besse-Beaver 345	TBD	TBD
	2241	MECS,FE	MONROE-BAY SHORE 345 FLO LULU-ALLEN 345	TBD	TBD
	2242	FE	BAY SHORE 345/138 TR FLO LULU 3-TERMINAL LINE 3	TBD	TBD
	2244	LGEE,TVA	Paddys-Summershade 161 flo Baker-Broadford 765	TBD	TBD
	2245	LGEE,EKPC	Blue Lick-Bullitt Co 161 flo Baker-Broadford 765	TBD	TBD
	2246	FE,MECS	Bay Shore-Monroe 345 flo Lemoyne-Davis Besse 345	TBD	TBD
	2247	FE	Beaver-Brookside 138 flo Beaver-Da 17.8	TBD	TBD
	2248	FE	Davis Besse-Beaver 345 flo Kammer-S Canton 765	TBD	TBD
	2249	FE,AEP	Brookside-Howard 138 flo Beaver-Davis Besse 345	TBD	TBD
	2250	FE	Hoyt-Maple 138 flo Sammis-Wylier 345	TBD	TBD
	2251	FE	Hoyt-Maple 138 flo Wylie Ridge-Cabot 500	TBD	TBD
	2255	FE,DPL	Kirby-Bluejacket 138 flo Mill Cree	TBD	TBD
	2256	FE	Mansfd-Highland 345 flo Mansfd-Hoytdl 345	TBD	TBD
	2257	FE,DLCO	Mansfd-Bvrval 345 #2 flo Mansfd-Crescent 345	TBD	TBD
	2258	FE	Richln-Ridgeville 138 flo Midw-Richln-Waus 138	TBD	TBD
	2259	FE,PJM	Sammis-Wylier 345 flo Kam-Har-FtM 3-Term line 500	TBD	TBD
	2260	FE,PJM	Wylie Ridge-Sammis 345 flo Kammer-S Canton 765	TBD	TBD
	2261	FE,PJM	Sammis-Wylier 345 flo Sammis-S Canton 345	TBD	TBD
	2262	FE	Sammis-Highland 345 flo Sammis-Bvrval 345	TBD	TBD
	2263	FE	Sammis-Star 345 flo S Canton-Star 345	TBD	TBD
	2264	FE	Star-Carlil 345 flo Avon-Juniper 345	TBD	TBD
	2265	FE	Star-Juniper 345 flo Hanna-Juniper 345	TBD	TBD
	2266	LGEE	Knob Creek-Pond Creek 138 (flo) Ghent-W. Lexington 345	TBD	TBD
	2268	LGEE	Smith-Green River Steel 138 flo Smith 345/138 Xfmr	TBD	TBD
	2269	NIPS	Leesburg-Northeast 138 flo Hiple 345/138	TBD	TBD
	2270	FE	Perry-Ashtabula 345 (flo) Wylie Ridge-Cabot 500	TBD	TBD
	2271	IPL,AEP	Wheatland-Breed 345 (flo) Rockport-Sullivan 765	TBD	TBD
	2272	LGEE,CIN	Ghent-Batesville 345 (flo) Ghent-W. Lexington 345	TBD	TBD
	2273	SIGE	A. B. Brown-Northwest 138 flo A. B. Brown-Henderson 138	TBD	TBD
	2276	FE	Star-Carlisle 345 flo Star-Juniper 345	TBD	TBD
	2277	EKPC, LGEE	Avon-Loudon 138 flo Ghent-West Lexington-Brown 345	TBD	TBD
	2278	FE	Avon-Beaver 345 #1 flo Avon-Beaver 345 #2	TBD	TBD
	2279	LGEE	Paddys West-Paddys Run 138 (flo) Cane Run-Cane Run 6 138	TBD	TBD
	2280	FE, AEP	Bay Shore-Fostoria 345 flo Lemoyne-Fostoria 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2281	SIGE	Newtonville 138/161 flo Henderson 138/161	TBD	TBD
	2282	FE	Beaver-Davis Besse 345 flo Galion-Fostoria 345	TBD	TBD
	2283	CIN	Bloomington-Denois Creek 230 flo Bedford-Columbus 345	TBD	TBD
	2284	LGEE, EKPC	Blue Lick-Bullitt Co. 161	TBD	TBD
	2285	LGEE	Paddys West – Paddys Run 138	TBD	TBD
x	2286	CE, NIPS	Burnham-Munster 345 flo Dumont-Wilton Center 765	MISO	MISO
x	2287	CE, NIPS	Burnham-Munster 345 flo Dumont-Wilton Center 765 + Op G	MISO	MISO
x	2288	CE, NIPS	Burnham-Sheffield 345 flo Dumont-Wilton Center 765	MISO	MISO
	2289	DLCO, FE	Beaver Valley-Hanna 345 flo Mansfield-Chamberlin 345	TBD	TBD
	2290	DLCO, FE	Beaver Valley-Sammis 345 flo Beaver Valley-Hanna 345	TBD	TBD
	2291	IPL,CIN	Petersburg-Oakland City 138 flo Gi 99.7	TBD	TBD
	2292	FE	Chamberlin-Harding 345 flo Star-Juniper 345	TBD	TBD
	2293	LGEE,CIN	Gallagher – Paddys West 138 (flo) 15.0	TBD	TBD
	2294	OVEC, LGEE	Clifty Creek-Carrollton 138 flo Baker-Broadford 765	TBD	TBD
	2295	SIGE,BREC	A. B. Brown-Henderson 138 flo Culley-Grandview 138	TBD	TBD
x	2296	CE,NIPS	Munster-Burnham 345 flo University Park North-E. Frankfort 345	MISO	MISO
x	2298	AEP,NIPS	New Carlisle-Trail Creek 138 flo University Park North-E. Frankfort 345	MISO	MISO
x	2299	AEP, NIPS	Dumont-Stillwell 345 flo Dumont-Wilton Center 765	AEP	PJM
	2304	PJM	01HATFLD 500 01YUKON 500 1	TBD	TBD
	2305	PJM	01WYLIER 500 O1CABOT 500 1	TBD	TBD
	2306	PJM	Wylie Ridge #5 345/500 kV xfmr	TBD	TBD
	2307	PJM	Wylie Ridge #7 345/500 kV xfmr	TBD	TBD
	2314	FE	DAVIS BESSE-BAY SHORE 345 flo DAVIS BESSE-LEMOYNE 345	TBD	TBD
	2315	FE	DAVIS BESSE-LEMOYNE 345 flo DAVIS BESSE-BAY SHORE 345	TBD	TBD
	2316	FE	ALLEN 345/138 Tr flo MONROE-BAY SHORE 345	TBD	TBD
	2317	FE	Bay Shore 345/138kV Tr	TBD	TBD
	2330	AEP	05BROADF 765 05J.FERR 765 1	TBD	TBD
	2331	AEP	05BAKER 765 05BROADF 765 1	TBD	TBD
	2332	AEP	05J.FERR 765 05CLOVRD 765 1	TBD	TBD
	2333	AEP	05KAMMER 765 05BELMON 765 1	TBD	TBD
	2334	AEP	05BELMON 765 05MOUNTN 765 1	TBD	TBD
	2336	AEP,MECS	BentnHrbr-Palisades345/Cook-Palisades345	TBD	TBD
	2337	AEP,MECS	Cook-Palisades345/BentnHrbr-Palisades345	TBD	TBD
	2338	MECS,AEP	Cook-Palisades345/TwinBranch-Argenta345	TBD	TBD
	2339	MECS,AEP	BentnHrbr-Palisades345/TwinBranch-Argenta345	TBD	TBD
	2340	MECS,AEP	TwinBranch-Argenta345/Cook-Palisades345	TBD	TBD
	2341	MECS,AEP	TwinBranch-Argenta345/Robison Pk-Argenta 345	TBD	TBD
	2350	PJM,AEP	BELMNT500/765TX-KAMMER500/765TX	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2351	PJM,AEP	KAMMER500/765TX-BELMNT500/765TX	TBD	TBD
	2352	PJM,VAP	PRNTY-MTSTM500/BLACKO-BEDNGT500	TBD	TBD
	2353	PJM	BLACKO-BEDNGT500-PRNTY-MTSTM500	TBD	TBD
	2356	PJM,VAP	PRNTY-MTSTM500-HATFIELD-BLACKO500	TBD	TBD
	2357	PJM	Wylie Ridge #7 345/500 xfmr l/o Wylie Ridge #5 345/500 xfmr	TBD	TBD
	2358	PJM	Wylie Ridge #5 345/500 xfmr l/o Wylie Ridge #7 345/500 xfmr	TBD	TBD
	2365	PJM	FT MARTN-PRNTY500/HARRSN-PRUNTY500	TBD	TBD
	2366	PJM,DLCO	MITCH-ELRAMA138/SAMMIS-WYLIER345	TBD	TBD
	2367	PJM,DLCO	MITCH-ELRAMA138/WYLIER-CABOT500	TBD	TBD
	2368	PJM,FE	SAMMIS-WYLIE RIDGE 345 FLO KAMMER 765/345 TR	TBD	TBD
	2369	PJM,AEP	Tidd-Wylie Ridge 345 kV line l/o Kammer 765/500 kV xfmr	TBD	TBD
	2370	PJM	BEDINGTON-DOUBS500/PRUNTY-MT STM50	TBD	TBD
	2371	PJM	Wylie Ridge #7 345/500 xfmr l/o Kammer 765/500 kV xfmr	TBD	TBD
	2372	PJM	Wylie Ridge #7 345/500 xfmr l/o Harrison-Wylie Ridge 500 kV	TBD	TBD
	2373	PJM	Wylie Ridge #7 345/500 xfmr l/o Belmont-Harrison 500 kV	TBD	TBD
	2374	PJM	Wylie Ridge #5 345/500 xfmr l/o Harrison-Wylie Ridge 500 kV	TBD	TBD
	2375	PJM	Wylie Ridge #5 345/500 xfmr l/o Belmont-Harrison 500 kV	TBD	TBD
	2376	PJM,VAP	PRNTY-MTSTM500/BEDINGTON-DOUBS500	TBD	TBD
x	2400	AEP	DUMONT765-345TX-COOK765-345TX	AEP	PJM
x	2401	CE,AEP	DUMONT765/345TX-DUMONT WILTON C 765	AEP	PJM
x	2402	AEP	COOK765-345TX-DUMONT765-345TX	AEP	PJM
	2403	AEP	KANAWZ-M FUNK 345/BAKER-BROADFORD 765	TBD	TBD
	2404	AEP	KANAWZ-M FUNK 345/BROADFORD-JFERRY	TBD	TBD
	2405	AEP	Kammer-W Belair 345/Kammer-S Canton 765	TBD	TBD
	2412	AEP	Waterford-Muskingum 345 kv / Mountaineer-Belmont 765 kv	TBD	TBD
	2413	AEP	S. Canton 765/345 kv Xfmr / Tidd-Canton Central 345 kv	TBD	TBD
	2414	AEP	S. Canton 765/345 kv Xfmr / Marysvl 765/345 kV Xfmr	TBD	TBD
	2415	AEP	S. Canton 765/345 kV Xfmr / Kammer 765/500 kV Xfmr	TBD	TBD
	2416	AEP	Muskingum River-Ohio Central 345 kV / E Lima-Fostoria 345 kV	TBD	TBD
	2417	AEP,DUK	J Ferry-Antioch 500kV / Broadford-Sullivan 500 kV	TBD	TBD
	2420	BREC,LGEE	COLEMN-NATAL 161/WILSN-GRN RVR 161	TBD	TBD
	2421	BREC,TVA,LGEE	HOPKIN CO-BARKLEY 161/WILSN-GRN RV	TBD	TBD
	2422	BREC	NEW HARDINSBG 138-161/COLEMN-NATAL 161	TBD	TBD
	2423	BREC,TVA	Hardinsburg-Paradise 161 kV	TBD	TBD
	2424	BREC,TVA	BRYAN / MARSHALL 161 KV	TBD	TBD
	2452	CIN	08SPEED 345/138 11GHENT 345 11W LEXN 345	TBD	TBD
	2454	CIN	Sugar Creek-Cayuga CT 345 flo Wheatland-Amo 345	TBD	TBD
	2455	CIN	Gibson 345/138	TBD	TBD
	2456	CIN	Gibson 345/138 Gibson Pete 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2457	CIN	Cayuga 345/230 XFMR 9 (flo) Cayuga 345/230 XFMR 10	TBD	TBD
	2460	CIN	08CAYUGA VDSBRG 230 08CAYUGA FRNKFT 230	TBD	TBD
	2461	CIN	08GIBSON WHEAT 345 08GIBSON 16PETE 345	TBD	TBD
	2462	CIN	Wheatland-Amo 345 flo Gibson-Petersburg 345	TBD	TBD
	2464	CIN	Frankfort-New London 230 flo Veedersburg-Cayuga 230	TBD	TBD
	2465	CIN	Speed-Ramsey 345 Buckner – Middletown 345	TBD	TBD
	2466	CIN	Zimmer to Port Union 345 kV	TBD	TBD
	2468	NIPS,AEP	Trail Creek-New Carlisle	TBD	TBD
	2470	FE,PJM	Ashtabula-Erie West 345 (flo) Sammis-Wylie Ridge 345	TBD	TBD
	2471	FE	Avon-Beaver #2 345 (flo) Avon-Beaver #1 345	TBD	TBD
	2472	FE	Chamberlin 345/138 (flo) Chamberlin-Harding 345	TBD	TBD
	2473	FE,DPL	Greene-Clark 138 (flo) Urbana-Clark 138	TBD	TBD
	2474	FE	East Lake 345/138 (flo) Perry-Inland 345	TBD	TBD
	2475	FE	Galion 345/138 TR1 (flo) Galion 345/138 TR2	TBD	TBD
	2476	FE	Mansfield-Chamberlin 345 (flo) Beaver Valley-Hanna 345	TBD	TBD
	2477	FE	Perry-Ashtabula 345 (flo) East Lake 345/138 TR 61	TBD	TBD
	2478	FE,PJM	Ashtabula-Erie West 345(flo) Mansfield-Chamberlin 345	TBD	TBD
	2479	FE	Carlisle-Lorain 138 (flo) Carlisle-Beaver 345	TBD	TBD
	2480	LGEE	TRIMBLE COUNTY – CENTERFIELD 138 K	TBD	TBD
	2481	LGEE	11TRIMBL 345 11TRIMBL 138	TBD	TBD
	2482	LGEE,EKPC	Marion 138/161 kv xfmr	TBD	TBD
	2483	EKPC,LGEE	Avon – Loudon 138 kV	TBD	TBD
	2484	LGEE,OVEC	Northside-Clify Creek 138 (flo) Trimble Co.-Clifty Creek 345	TBD	TBD
	2485	LGEE,CIN	Gallagher-Paddys West 138 (flo) Tr -33.7	TBD	TBD
	2486	LGEE,CIN	Speed-Northside 138 (flo) Trimble Co.-Clifty Creek 345	TBD	TBD
	2488	LGEE,EKPC	11BLUE L 161 20BLIT C 161 1 flo 11GHENT 345 11W LEXN 345	TBD	TBD
	2490	FE	Lorain-Johnson 138 (flo) Avon 345/138 TR	TBD	TBD
	2493	FE,DLCO	Beaver Valley 1-Mansfield 345 (flo) Beaver Valley 2-Mansfield 345	TBD	TBD
	2494	FE,AEP	East Leipsic-Richland 138 flo East Lima-Robison Park	TBD	TBD
	2495	FE,AEP	Richland-Lockwood 138 flo East Lima-Robison Park 345	TBD	TBD
	2496	FE,AEP	Canton Central-Cloverdale 138 (flo) Torrey-Cloverdale 138	TBD	TBD
x	2497	NIPS	State Line-Wolf Lake 138	MISO	MISO
	2498	FE,AEP	West Canton-Dale 138 (flo) South C	TBD	TBD
	2500	SIGE,LGEE	10NEWTVL-11CLVRPR 138/COLEMN-NATAL 161	TBD	TBD
	2503	FE	Torrey-Cloverdale 138 (flo) Muskingum-Ohio Central-Galion 345	TBD	TBD
	2504	FE	Hanna-Juniper 345 (flo) Mansfield-Chamberlin 345	TBD	TBD
	2505	FE	Perry-Ashtabula 345 (flo) Sammis-W.Ridge 345	TBD	TBD
	2550	IPL	Petersburg 345/138 xfmr (East)	TBD	TBD
	2551	IPL	Petersburg 345/138 xfmr (East) flo Petersburg 345/138 xfmr (West)	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2853	MECS	19001 CVTRY 345-120/MADRD-MAJTC	TBD	TBD
	2854	MECS	CVTRY 345-120/MON34-BRSTNN	TBD	TBD
	2855	MECS	MON12-BNSTNS/MON12-WAYNE	TBD	TBD
	2856	MECS	MON12-WAYNE/MON12-BNSTNS	TBD	TBD
	2859	MECS,FE	BAYSHORE-MONROE 345 FLO ALLEN-LULU 345, LULU-MAJESTIC 345, & LULU-MONROE 345	TBD	TBD
	2861	MECS,FE	Monroe-Bay Shore 345 flo Fostoria-Bay Shore 345	TBD	TBD
	2863	MECS	Argenta-Battle Creek 345 flo Argenta-Tompkins 345	TBD	TBD
	2864	MECS	Argenta-Morrow 138 flo Argenta-Battle Creek 345	TBD	TBD
	2865	MECS	Atlanta Jct.-Atlanta 138 flo Thetford-Jewell 345	TBD	TBD
	2866	AEP, MECS	Cook-Palisades 345 flo Cook-Benton Harbor 345	TBD	TBD
	2867	MECS	Delhi-Tompkins 138 flo Argenta-Tompkins 345	TBD	TBD
	2868	MECS	Detroit Industrial-Waterman 230 flo Detroit Industrial-Navare 230	TBD	TBD
	2869	FE	Eastlake-Juniper 345 flo Perry-Harding 345	TBD	TBD
	2870	LGEE	Northside-Beargrass 138 flo Northside-Jeffersonville Jct. 138	TBD	TBD
	2871	BREC, LGEE	New Hardinsburg-Hardinsburg 138	TBD	TBD
	2872	LGEE	Frankfort East-Tyrone 138 flo Ghent-West Lexington 345	TBD	TBD
	2873	AEP, FE	Fostoria-Lemoyne 345 flo Davis Besse-Lemoyne 345	TBD	TBD
	2874	LGEE	Fawkes-Fawkes Tap 138 flo Fawkes-EKPC Fawkes 138	TBD	TBD
	2875	FE, AEP	Galion-Fostoria 345 flo Beaver-Davis Besse 345	TBD	TBD
	2876	LGEE	Northside-Jeffersonville Jct. 138 flo Northside-Beargrass 138	TBD	TBD
	2878	LGEE	Ghent-Owen County Tap 138 flo Ghent-West Lexington 345	TBD	TBD
	2879	LGEE	Ghent-West Lexington 345	TBD	TBD
	2880	HE	GPC-Ratts 161	TBD	TBD
	2881	LGEE	Grahamville-South Paducah 161	TBD	TBD
	2882	FE	Ottawa-Toussaint 138 flo Beaver-Davis Besse 345	TBD	TBD
	2883	LGEE	Green River-River Queen Tap 161	TBD	TBD
	2884	LGEE	Green River Steel-Cloverport 138 flo Smith-Hardin County 345	TBD	TBD
	2885	LGEE	Haefling-IBM North Jct. 138	TBD	TBD
	2886	MECS	Hemphill-Hunters Creek 120 flo Hampton-Pontiac 345	TBD	TBD
	2887	MECS	Hemphill-Hunters Creek 120 flo Thetford-Jewell 345	TBD	TBD
	2888	MECS	Hampton-Pontiac 345 flo Thetford-Jewell 345	TBD	TBD
	2889	MECS	Island Rd-Canal 138 flo Argenta-Tompkins 345	TBD	TBD
x	2890	CE,NIPS	State Line-Wolf Lake 138 flo E. Frankfort-University Park North 345	MISO	MISO
	2893	PJM, FE	Krendale-Seneca 138	TBD	TBD
	2894	PJM, FE	Krendale-Seneca 138 flo Mansfield-Hoytdale 345	TBD	TBD
	2895	PJM, FE	Krendale-Seneca 138 flo Wylie Ridge-Sammis 345	TBD	TBD
	2896	MECS	Latson-Genoa 138 flo Thetford-Jewell 345	TBD	TBD
	2897	FE, AEP	Lemoyne-Fostoria 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2898	FE	Torrey-Cloverdale 138 (flo) CantonCentral-Cloverdale 138	TBD	TBD
	2899	FE, AEP	Lemoyne-West End 138 flo Lemoyne-Fostoria 345	TBD	TBD
	2900	FE,AEP	Tangy-Hyatt 345 (flo) Marysville-Orange 765	TBD	TBD
	2902	FE	Sammis-Highland 345 (flo) Mansfield-Highland 345	TBD	TBD
	2904	FE, DLCO	Mansfield-Beaver Valley 345 #2 flo Mansfield-Beaver Valley 345 #1	TBD	TBD
	2905	FE	Richland-Ridgeville 138 (flo) Richland-Lockwood 138	TBD	TBD
	2906	FE, DLCO	Mansfield-Crescent 345 flo Beaver Valley-Crescent 345	TBD	TBD
	2907	FE	Mansfield-Hoytdale 345 flo Mansfield-Highland 345	TBD	TBD
	2908	CIN	Miami Fort 345/138 Xfm flo East Bend-Terminal 345	TBD	TBD
	2909	MECS	McGulpin-Riggsville 138 flo McGulpin-Oden 138	TBD	TBD
	2910	LGEE	Middletown 345/138 Xfm #1 flo Middletown 345/138 Xfm #3	TBD	TBD
	2911	LGEE	Middletown-3842 Tap 138 flo Blue Lick 345/138 Xfm	TBD	TBD
	2912	LGEE	Mill Creek-Manslick 138 flo Cane Run 6-Cane Run Switching 138	TBD	TBD
x	2913	NIPS,AEP	Stillwell-Dumont 345	MISO	MISO
	2914	AEP, FE	Marysville-Tangy 345	TBD	TBD
	2915	SIGE, LGEE	Newtonville-Cloverport 138	TBD	TBD
	2916	SIGE, HE	Newtonville-Troy 161	TBD	TBD
	2917	AEP, FE	Ohio Central-Galion 345 flo E. Lima-Fostoria 345	TBD	TBD
	2918	MECS	Oneida-Majestic 345	TBD	TBD
	2919	FE	Ottawa-Lakeview 138 flo Davis Besse-Beaver 345	TBD	TBD
	2920	MECS, AEP	Palisades-Benton Harbor 345 flo Twin Branch-Argenta 345	TBD	TBD
	2921	MECS, AEP	Palisades-Cook 345 flo Twin Branch-Argenta 345	TBD	TBD
	2923	TVA, LGEE	Phipps Bend-Pocket North 500	TBD	TBD
	2925	LGEE, CIN	Ghent-Fairview 138 flo Ghent-Batesville 345	TBD	TBD
	2926	NIPS,AEP	Maple-New Carlisle 138	TBD	TBD
	2927	MECS	Roosevelt-Campbell 345 flo Roosevelt-Tallmadge 345	TBD	TBD
	2928	LGEE	River Queen Tap-Earlington North 161	TBD	TBD
	2929	FE, DLCO	Sammis-Beaver Valley 345 flo Sammis-Highland 345	TBD	TBD
	2930	NIPS,AEP	Michigan City-Laporte Junction 138	TBD	TBD
	2931	FE, AEP	Sammis-S. Canton 345 flo Sammis-Star 345	TBD	TBD
	2932	FE, AEP	Sammis-S. Canton 345 flo Sammis-Wylie Ridge 345	TBD	TBD
	2934	FE, PJM	Sammis-Wylie Ridge 345 flo Tidd-Wylie Ridge 345	TBD	TBD
	2935	AEP, FE	S. Canton-Star 345 flo Sammis-Star 654.7	TBD	TBD
	2936	FE, PJM	Seneca-Krendale 138 flo Wylie Ridge-Cabot 500	TBD	TBD
	2937	FE	Seneca-Maple 138 flo Mansfield-Hoytdale 345	TBD	TBD
	2938	FE	Seneca-Maple 138 flo Wylie Ridge-Sammis 345	TBD	TBD
	2939	CIN, LGEE	Speed-Northside 138 flo Rockport-Jefferson 765	TBD	TBD
	2940	CIN	Speed 345/138 Xfm flo Rockport-Jefferson 765	TBD	TBD
	2943	FE	Star-Juniper 345 flo Star-Carlisle 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	2944	MECS, IMO	St. Clair 345/230 Xfm T9 flo St. Clair-Lambton 345	TBD	TBD
	2946	HE	Taswell-Bedford 161 53.7	TBD	TBD
	2947	HE	TASWELL-RATTS 161KV	TBD	TBD
	2948	MECS	Thetford-Jewell 345 flo Hampton-Pontiac 345	TBD	TBD
	2949	LGEE	Tip Top-Cloverport 138 flo Baker-Broadford 765	TBD	TBD
	2950	MECS	Tompkins-Majestic 345 flo Oneida-Majestic 345	TBD	TBD
	2951	AEP, MECS	Twin Branch-Argenta 345 flo Cook-Benton Harbor 345	TBD	TBD
	2952	MECS	Whiting 138/120 Xfm flo Oneida-Majestic 345	TBD	TBD
	2953	MECS	Whiting 138/120 Xfmr flo Tompkins-Majestic 345	TBD	TBD
	2954	BREC, LGEE	Wilson-Green River 161	TBD	TBD
	2955	HE	Worthington-GPC 161	TBD	TBD
	2956	NIPS,AEP	Northport-Albion 138	TBD	TBD
	2957	CIN	Zimmer-Silver Grove 345 flo Zimmer-Port Union 345	TBD	TBD
	2958	HE, CIN	Merom-Dresser 345 (flo) Gibson-Petersburg 345	TBD	TBD
	2959	CIN	Cayuga-Nucor (flo) Wheatlan-Amo	TBD	TBD
	2960	CIN	Greentown 765/138 XFMR 1 (flo) Greentown 765/230/138 XFMR 2	TBD	TBD
	2961	CIN, HE	Worthington-Owen 138 (flo) Worhtington-Bloomington 345	TBD	TBD
	2962	CIN, AEP	Greentown 765/230/138 XFMR 2 (flo) Greentown-Dumont 765	TBD	TBD
	2963	LGEE, CIN	Ghent-Fairview 138 (flo) Ghent-Batesville 345	TBD	TBD
	2964	HE, CIN	Merom-Dresser 345 (flo) Merom-Worthington 345	TBD	TBD
	2965	CIN, HE	Gibson-Merom 345 (flo) Gibson-Petersburg 345	TBD	TBD
	2966	CIN	Bloomington-Columbus 230 (flo) Bedford-Columbus 345	TBD	TBD
	2967	CIN	Wabash River-Whitesville 230 (flo) Wabash River-Clinton 230	TBD	TBD
x	3001	CE,ALTE	WEMPLETOWN-PADDOCK 345 KV	MISO	MISO
	3002	ALTE	NELSON-DEWEY 161/138 XFMR	TBD	TBD
x	3003	ALTE	COLUMBIA-S. FOND DU LAC 345 KV	MISO	MISO
	3004	ALTE,MGE	COLUMBIA-N. MADISON 345 KV	TBD	TBD
	3005	ALTE,WPS	S. FOND DU LAC-FITZGERALD 345 KV	TBD	TBD
x	3006	ALTE,NSP,WEC,WPS	EAU CLAIRE-ARPIN 345 KV	MISO	MISO
	3007	WPS	ELLINWOOD-PROGRESS 138 KV	TBD	TBD
x	3009	NSP,ALTE,WEC,WPS	EAU CLAIRE-ARPIN+WEMPLETOWN-PADDOCK	MISO	MISO
	3010	ALTE	ROCKDALE 345/138 XFMR 1	TBD	TBD
x	3011	ALTE	PADDOCK 345/138 XFMR 1	MISO	MISO
x	3012	ALTE	PADDOCK XFMR 1 + PADDOCK-ROCKDALE	MISO	MISO
	3013	ALTE	ROCKDALE XFMR 1 + ROCKDALE XFMR 2	TBD	TBD
	3014	ALTE	ROCKDALE XFMR 2 + PADDOCK XFMR	TBD	TBD
	3015	ALTE	NELSON DEWEY XFMR+WMPLETOWN-PADDOCK	TBD	TBD
	3016	ALTE	NELSON DEWEY XFMR + ECL-ARP+Guide	TBD	TBD
	3017	ALTE,DPC	Cassvl-NED 161 for Wemp-Paddock 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3018	ALTE,WPS,WEC,NSP	EAU CLAIRE-ARPIN+PRAIRIE ISLAND-BYRON	MISO	MISO
	3020	ALTE	Rockdale Xfmr 1 for Paddock Xfmr	TBD	TBD
x	3021	ALTE	Paddock-Blackhawk 138 (flo) Paddock-Townline 138	MISO	MISO
	3022	ALTE	X59 Christiana-Kegonsa 138 for Columbia-N Madison 345	TBD	TBD
	3023	ALTE	ROE-Lkhd 138 for EauClair-Arp, Wien-Tcorners	TBD	TBD
x	3024	ALTE	Blackhwk-Colley Road 138 (flo) Paddock-Townline 138	MISO	MISO
x	3025	ALTE	Russel-Rockdale 138/Paddock-Rockda 154.1	MISO	MISO
	3026	ALTE	Rockdale TR2 for Rockdale TR 1	TBD	TBD
	3027	ALTE	Burlington-N Lk Geneva Tp flo Wempltown-Paddock	TBD	TBD
	3028	ALTE	Sand Lk-P Edwards 138 for N.Appl-Ror 345	TBD	TBD
	3029	ALTE	Green Lk-Roeder 138kV	TBD	TBD
	3030	ALTE	Green Lk-Roeder 138 for N Appleton-RoR 345	TBD	TBD
	3031	ALTE	X59 Christiana-Kegonsa 138 for F1 Christiana-Fitchburg 138	TBD	TBD
	3032	WPS	ROCKY RUN –NORTHPT+WESTON-ROCKY RUN	TBD	TBD
	3033	ALTE	Arpin Xformer+Arpin-Rocky Run 345	TBD	TBD
x	3034	ALTE	Blackhawk-ColleyRd xfmr FLO Paddock-Rockdale345	MISO	MISO
	3035	ALTE	Columbia-Portage138 FLO Columbia-Portage138 ckt2	TBD	TBD
	3036	ALTE	Columbia-Portage138 ckt2 FLO Columbia-Portage138	TBD	TBD
	3037	ALTE	Edgewater-S.SheboygnFls138 FLO Edgwtr-S.FndDuLac138	TBD	TBD
x	3038	ALTE	Paddock-Townline 138 (flo) Paddock-Blackhawk 138	MISO	MISO
	3039	ALTE	Rockdale 345-138 T1 FLO Rockdale 345-138 T3	TBD	TBD
	3040	ALTE	Rockdale 345-138 T2 FLO Rockdale 345-138 T3	TBD	TBD
	3041	ALTE, MGE	Columbia-N.Madison138 FLO Columbia-NMA345	TBD	TBD
	3042	ALTE	Townline-Janesville 138 (flo) Paddock-Rockdale 345	TBD	TBD
	3043	ALTE	Townline-Janesville 138 flo Townline-Tripp-Viking-Russell 138	TBD	TBD
	3044	ALTE	Townline-Janesville 138 flo Rockdale 345/138 Xfmr 3	TBD	TBD
x	3045	ALTE	Rockdale 345/138 Xfmr 3 flo Paddock 345/138 Xfmr	MISO	MISO
	3046	ALTE	Portage-Hamilton 138 flo Columbia-South Fond du Lac 345	TBD	TBD
	3047	ALTE	Arpin 345/138 Xfm flo Eau Claire-Arpin 345 + Op Guide	TBD	TBD
	3048	ALTE	Christiana-Kegonsa 138 flo N. Madison 345/138 Xfm #1 + Op Guide	TBD	TBD
	3049	ALTE	Columbia 345/138 Xfm #1 flo Columbia 345/138 Xfm #2	TBD	TBD
	3052	ALTE	Nelson Dewey 161/138 Xfm flo Arpin-Rocky Run 345 + Op Guide	TBD	TBD
	3053	ALTE	N. Madison 345/138 Xfm #1 flo N. Madison 345/138 Xfm #2 + Bus Tie	TBD	TBD
	3054	ALTE, WEC	Rockdale-Lakehead 138 flo Columbia-S. Fond du Lac 345	TBD	TBD
	3057	ALTE	T Corners-Wien 115 flo Arpin-Rocky Run 345 + Op Guide	TBD	TBD
	3058	ALTE	T Corners-Wien 115 flo Eau Claire-Arpin 345 + Op Guide	TBD	TBD
x	3059	CE, ALTE	Wempletown-Paddock 345 flo Arpin-Rocky Run 345 + Op Guide	MISO	MISO
x	3060	CE, ALTE	Wempletown-Paddock 345 flo King-Eau Claire-Arpin 345 + Op Guide	MISO	MISO

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3061	ALTE	Whitewater-Mukwonago 138 flo Paddock 345/138 Xfm	TBD	TBD
	3062	ALTE	Whitewater-Mukwonago 138 flo Paddock-Rockdale 345	TBD	TBD
x	3063	ALTE	Paddock-Townline 138 (flo) Paddock-Rockdale 345	MISO	MISO
	3102	AMRN,AECI	BLAND-FRANKS 345 KV	TBD	TBD
	3103	AMRN	CAHOKIA 345/138 XFMR 8	TBD	TBD
	3104	AMRN	CAHOKIA 345/138 XFMR 9	TBD	TBD
	3105	AMRN,EEI	JOPPA-CAPE GIRARDEAU 161 KV	TBD	TBD
	3106	AMRN	MASON 345/138 XFMR 2	TBD	TBD
x	3107	AMRN	MONTGOMERY-SPENCER 345 KV	MISO	MISO
	3108	AMRN,MPS	OVERTON-SIBLEY 345 KV	TBD	TBD
	3109	AMRN	RUSH ISLAND-ST FRANCOIS 345 KV	TBD	TBD
	3110	AMRN	QUINCY S-QUINCY E 138	TBD	TBD
	3111	IP,AMRN	XENIA –MT VERNON 345 KV	TBD	TBD
x	3112	AMRN,CILC	DUCK CREEK-IPAVA 345 kV	MISO	MISO
	3113	AMRN	NEWTON-CASEY 345 KV	TBD	TBD
x	3114	AMRN,AEP	BREED-CASEY 345 KV	MISO	MISO
x	3115	AMRN	COFFEEN-PANA 345 KV	MISO	MISO
	3116	AMRN	ALBION 345/138 XFMR	TBD	TBD
	3117	AMRN,AECI	Bland-Franks345 + Rush-St Francios + TR	TBD	TBD
	3118	AMRN	ALBION-XFMR + BREED-CASEY	TBD	TBD
x	3120	AMRN	COFFEEN-PANA+MONTGMRY-SPENCER	MISO	MISO
	3121	AMRN	ALBION XFMR + GIBSON-PETERSBURG	TBD	TBD
	3122	AMRN	ALBION XFMR + DUMONT-WILTON CENTER	TBD	TBD
x	3123	AMRN	COFFEEN-PANA+DUMONT-WILTON CENTER	MISO	MISO
	3124	AMRN,EEI	JOPPA-CAPE GIRARDEAU+SHAWNEE-KELSO	TBD	TBD
	3125	AMRN	SIDNEY-RANTOUL + SIDNEY-MIRA TAP	TBD	TBD
	3126	AMRN	SIDNEY-RANTOUL + COFFEEN-PANA-KINCAID	TBD	TBD
x	3127	AMRN	TAYLORVILLE-PAWNEE + COFFEEN-PANA-KINCAID	MISO	MISO
	3128	AMRN	S QUINCY-E QUINCY+QUINCY S-QUINC E	TBD	TBD
	3129	AMRN	MASON XFMR #3 + MASON XFMR #2	TBD	TBD
	3130	AMRN	ST FRANC XFMR+ST FRANC-LUTESVILLE	TBD	TBD
x	3131	AMRN	PAWNE-AUBURN+KINCAID-LATHM	MISO	MISO
	3132	AMRN	MURDOCK-SIDNEY + SIDNEY XFMR	TBD	TBD
	3133	AMRN	LABADIE-MASON3 + LABADIE-MASON4	TBD	TBD
	3134	AMRN	MISS TAP-ROXFRD1+MISS TAP ROXFRD 3	TBD	TBD
	3135	AMRN	ALBION-CROSSVL + XENIA-MT VERNON	TBD	TBD
	3138	AMRN	MONTGMRY-GUTHRIE+MONTGMRY MCCREDIE	TBD	TBD
x	3139	AMRN	PAWNEE WEST XFMR + PANA-KINCAID	MISO	MISO
x	3140	AMRN	MONTGMRY-SPENCER+COFFEEN-PANA-KINCAID	MISO	MISO

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3141	AMRN	MIS TAP3-ROXFRD + MIS TAP1-ROXFORD	TBD	TBD
x	3142	AMRN	RAMSEY-PANA + COFFEEN-PANA-KINCAID	MISO	MISO
	3143	AMRN	CAHOKIA XFMR 9 + CAHOKIA XFMR 8	TBD	TBD
	3144	AMRN	RUSH-ST FRANCOIS + BLANDS-FRANKS	TBD	TBD
x	3145	AMRN	PANA XFMR + COFFEEN-COFFEEN NORTH	MISO	MISO
	3146	AMRN,IP	MEREDOSIA-IND PARK+DUCK CRK-TAZEWL	TBD	TBD
	3147	AMRN,IP	MASON CTY-MT PLSKI FOR DUCK CRK-TAZEWL	TBD	TBD
	3148	AMRN	SIOUX-MISS TAP3+SIOUX-MISS TAP1	TBD	TBD
	3149	AMRN	SIOUX-MISS TAP3	TBD	TBD
	3150	AMRN	Newton 345/138 #2 for Newt-Casey345	TBD	TBD
	3152	AMRN	Meremac-St.Francois1Meremac-St.Francois2	TBD	TBD
	3153	AMRN	Clark Xfmr Bland-Franks	TBD	TBD
	3154	AMRN	Meremac-St.Francois Bland-Franks	TBD	TBD
	3157	AMRN	McCredie-Overton345 for Bland-Franks 345	TBD	TBD
x	3159	AMRN	Neoga-Holland-Ramsey 345 Bland-Franks 345	MISO	MISO
	3160	AECI,AMRN	Bland-Franks 345 for McCred-Overton 345	TBD	TBD
x	3161	AMRN, CWLP	Auburn-Chatham 138 flo Latham-Kincaid 345	MISO	MISO
	3162	SIPC,AMRN	Marion-S. Marion 161	TBD	TBD
	3163	SIPC, BREC	Renshaw-Livingston 161	TBD	TBD
	3164	SIPC,BREC	Renshaw-Livingston flo E. W Frankfort-Shawnee 345	TBD	TBD
	3165	SIPC,AMRN	S. Marion-Marion 161	TBD	TBD
x	3201	CE,AEP	11215 DUMONT-WILTON 765KV(AEP-CE)	PJM	PJM
x	3202	CE	17723 BURNHAM-TAYLOR 345KV	PJM	PJM
x	3203	CE	10802 LOCKPORT-LISLE 345 KV RED	PJM	PJM
x	3204	CE	10801 LOCKPORT-LISLE 345 KV BLUE	PJM	PJM
x	3205	CE	16703 PLANO- ELECT JCT 345 KV RED	PJM	PJM
x	3206	CE	16704 PLANO-ELECT JCT 345 KV BLUE	PJM	PJM
x	3207	CE	TSS116 GOODINGS GR 345KV RED BUSTIE	PJM	PJM
x	3208	CE	0621 BYRON-CHERRY VALLEY 345KV BLU	PJM	PJM
x	3209	CE	622 BYRON-CHERRY VALLEY 345KV RED	PJM	PJM
x	3210	CE	10802 Lock-LisR for 10801Lock-LiB+G	PJM	PJM
x	3211	CE	10801 Lock-LisB for 10802Lock-LiR+G	PJM	PJM
x	3212	CE	10802 Lock-Lisl R for 16703 PL-EJ R	PJM	PJM
x	3213	CE	10801 Lock-Lisl B for 16704 PL-EJ B	PJM	PJM
x	3214	CE	10322 Lis-LomR for 10321 Lis-LomB+G	PJM	PJM
x	3215	CE	10321 Lis-LomB for 10322 Lis-LomR+G	PJM	PJM
x	3216	CE	0621 Byron-ChV B for 0622 Byr-ChV R	PJM	PJM
x	3217	CE	0621 Byron-ChV B for 0624 Byr-Wemp	PJM	PJM
x	3218	CE	0622 Byron-ChV R for 0621 Byr-ChV B	PJM	PJM

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3219	CE	0622 Byr-ChV Red for 0624 Byr-Wemp	PJM	PJM
x	3220	CE	16704 Plan-EJ B for 16703 Plan-EJ R	PJM	PJM
x	3221	CE	16703 Plan-EJ Red for 16704 Pl-EJ B	PJM	PJM
x	3222	CE	11601 EFrk-GoodiB for 11602 EF-GG R	PJM	PJM
x	3223	CE	11602 EFrk-GoodiR for 11601 EF-GG B	PJM	PJM
x	3227	CE	0404 Quad-H471 for 15503 Cordo-Nelson	PJM	PJM
x	3228	CE	0403 Quad-Cord-Nelson for 0404 Quad-H471	PJM	PJM
x	3229	CE	11604 Goodi-LockR for 11617GG-LockB	PJM	PJM
x	3230	CE	11617 Goodi-LockB for 11604GG-LockR	PJM	PJM
x	3231	CE	GOODI 345R BT for 1223Dres-EJ B+T83	PJM	PJM
x	3232	CE	11120 EJ-W407 for 10802 Lock-LiR +	PJM	PJM
x	3233	CE	11124 EJ-Lomb for 10801 Lock-LiB +	PJM	PJM
x	3234	CE	2102 Kincaid-Lath for 11215 Dum-Wlt	PJM	PJM
x	3235	CE	2101 Kinc-BrokTp for 11215 Dum-Wilt	PJM	PJM
x	3236	CE,ALTE	17101 Wemp-Pad for 9922 Zion-Arcad	MISO	MISO
x	3237	CE,ALTE	17101 Wemp-Pad for 2221 Zion-PlsPr	MISO	MISO
x	3238	CE,ALTE	17101 Wemp-Pad for 15616 ChV-Silver	MISO	MISO
x	3239	CE,ALTE	17101 Wemp-Pad for Arpin-ÉauClar +G	MISO	MISO
x	3240	CE,WEC	2221 Zion-PlsPr for 9922 Zion-Arcd	PJM	PJM
x	3241	CE,WEC	2221 Zion-PlsP for 17101 Wemp-Pad	PJM	PJM
x	3242	CE,WEC	9922 Zion-Arcad for 2221 Zion-PlsP	PJM	PJM
	3243	CE,WEC	9922 Zion-Arcad for 17101 Wemp-Pad	TBD	TBD
x	3244	CE	Nels Tr84 for 15502 Nels-EJ +Tr82	PJM	PJM
x	3245	CE	15616 Cher-Silv for 15502 Nels-EJ	PJM	PJM
x	3248	CE	12204 Bel-Mar R for 15616 ChV-Silv	PJM	PJM
x	3249	CE	12205 Bel-Mar B for 15616 ChV-Silv	PJM	PJM
x	3250	CE	15502 Nels-EJ for 15616 Cher-Silv	PJM	PJM
x	3251	CE	0404 Quad Cities – NWS&W (H471)	PJM	PJM
x	3252	CE	11622 Elwd-GG R 345 for 1223 Dres-EJ R + Dres Tr 81	PJM	PJM
x	3253	CE	Kewanee(CE)-Kewanee(IP) 138 BT	PJM	PJM
x	3254	CE	Pwr JctB-Powerton 138	PJM	PJM
x	3257	CE,MEC	Quad City-SUB 91 345 KV	PJM	PJM
x	3258	CE,ALTW,MEC	Quad City-Rock Creek (FLO) QC-SUB91	PJM	PJM
x	3259	CE,MEC	Quad-SUB 91 345 for MEC Cordova-SUB 39(Moline) 345kV	PJM	PJM
x	3260	CE	15501 Lee Co-Nelson 345 for 17101 Wemp-Pad 345	PJM	PJM
x	3261	CE	L8012 Pontiac-Wiltn345 for L8014 Pont-Dresd345	PJM	PJM
x	3262	CE	Nelson 345-138 T82 for Nelson 345-138 T84	PJM	PJM
x	3263	CE	Nelson-Dixon B FLO Nelson-Nelson RT	PJM	PJM
x	3264	CE	Nelson-Nelson RT FLO Nelson-Dixon B	PJM	PJM

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	3265	CE	OTDF ChV-Bel Red FLO ChV-SilvLk	PJM	PJM
x	3266	CE, ALTW	Garden Plain-Albany 138 flo Quad Cities-H471 345	PJM	PJM
x	3267	NIPS, CE	Munster-Burnham 345 flo Dumont-Wilton Center 765 + Op G	MISO	MISO
x	3268	NIPS, CE	Munster-Burnham 345 flo Dumont-Wilton Center 765	MISO	MISO
x	3269	NIPS, CE	Sheffield-Burnham 345 flo Dumont-Wilton Center 765	MISO	MISO
x	3270	CE, NIPS	State Line-Wolf Lake 138 flo Burnham-Sheffield 345	MISO	MISO
x	3271	CE, NIPS	State Line-Wolf Lake 138 flo Wilton Center-Dumont 765	MISO	MISO
x	3301	CILC	TAZEWELL – MASON 138 KV -50.0	MISO	MISO
x	3302	CILC	East Springfield-Holland 138 KV	MISO	MISO
x	3303	CILC,CWLP	E SPRINGFIELD-EASTDALE 138 KV	MISO	MISO
x	3304	CILC,CE	POWERTON-TAZEWELL 345 KV	MISO	MISO
x	3306	CILC	Holland-Mason138+Duck Creek-Tazewe 121.2	MISO	MISO
	3307	CWLP, CILC	Eastdale-E. Springfield 138 flo Kincaid-Latham-Pontiac	TBD	TBD
	3308	CILC	Holland-Mason 138 57.7	TBD	TBD
	3309	CILC	Kickapoo-Holland 138	TBD	TBD
x	3310	CE, CILC	Powerton-Tazewell 345 flo Powerton-Goodings Gr. 345 B	MISO	MISO
x	3311	CE, CILC	Powerton-Tazewell 345 flo Powerton-Goodings Gr. 345 R	MISO	MISO
	3350	SIPC	Renshaw-Livingston 161 for Kelso-Joppa 345	TBD	TBD
	3351	IP,SIPC	Campbell Hill-Campbell Hill Tap 138	TBD	TBD
x	3401	IP	SIDNEY XFMR + BUNSONVILLE XFMR	MISO	MISO
	3402	AMRN,IP	CAHOKIA-BALDWIN+COFFEEN-ROXFRD TAP	TBD	TBD
	3403	IP	SIDNEY-MIRA TAP + SIDNEY-SW CAMPUS	TBD	TBD
	3404	IP	STALLINGS XFMR+COFFEEN-ROXFORD TAP	TBD	TBD
x	3405	IP,AEP	BUNSONVILLE-EUGENE + BREED-CASEY	MISO	MISO
	3406	AMRN,IP	CAHOKIA-BALDWIN+STALLING-ROXFD TP	TBD	TBD
	3407	IP	STALLING XFMR + STALLINGS-ROXFORD	TBD	TBD
x	3408	IP	PANA-MOWEAQ T + KINCAID-LATHAM 146.7	MISO	MISO
	3409	IP	PANA-MOWEAQ T + PONTIAC-LATHAM	TBD	TBD
x	3410	IP	SIDNEY XFMR + DUMONT-WILTON	MISO	MISO
	3411	IP	SIDNEY-MIRA + SIDNEY-RANTOUL	TBD	TBD
	3412	IP	FAYET-TILDEN + BALDWN-MT VR345/138	TBD	TBD
x	3413	AMRN,IP	COFFN-ROXFD IP FOR XENIA-MT VRNON	MISO	MISO
x	3414	AMRN,IP	COFFN-ROXFD IP FOR COFFN-COFFN N	MISO	MISO
x	3416	IP	COFFEEN-ROXFORD 345	MISO	MISO
x	3418	IP	COFFEEN-ROXFORD 345 FOR LOSS OF BAKER-BROADFORD 765	MISO	MISO
x	3419	IP,AMRN	Xenia-MtVernon 345 for Coffeen-Roxfd 345	MISO	MISO
x	3420	IP	Coffeen-Roxford Rockport-Jefferson	MISO	MISO
	3421	AMRN	Rush Isl-St Francios 345 for Franks-Salem 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3422	AMRN	Rush Isl-St Francios345 for Wfrank-Mt Vern345	TBD	TBD
	3423	AMRN	Bland-Franks 345 for Lutes-Essx345,Kelso Guid	TBD	TBD
	3424	IP	Salem-W Mt Vernon Xenia-W MT Vernon	TBD	TBD
	3425	IP	Gillespie-Lacleed Tap 138 + Xenia-MtVern 345	TBD	TBD
	3426	IP	Baldwin-Cahokia 345 for Baldw-Stallings,Stal TR	TBD	TBD
	3427	SIPC,IP	Campbell Hill Tap-Campbell Hill 138	TBD	TBD
	3428	IP, MEC	Galesburg 161/138 Xfm #2 flo Elect	TBD	TBD
	3501	WEC	Whitewater-Mukwonago 138 flo King-Arpin 345 kV	TBD	TBD
	3502	WEC	OAK CREEK 345/230 XFMR	TBD	TBD
x	3503	WEC	ALBERS-PARIS 138 KV	MISO	MISO
	3504	WEC	PARIS-ST MARTINS 138 KV	TBD	TBD
	3505	WEC	FREDONIA-Cedarsauk 138 KV	TBD	TBD
	3506	WEC	ARCADIAN 345/138 XFMR	TBD	TBD
x	3507	ALTE,WEC	EDGEWATER-Cedarsauk-Granville 345 KV	MISO	MISO
	3508	WEC	BLUEMOUND-TOSA-W 138 KV	TBD	TBD
	3510	WEC	CONCORD-COONEY 138 KV	TBD	TBD
	3511	WEC	MUKWONAGO-ST MARTINS 138 KV	TBD	TBD
	3512	WEC	LS – WHITEWATER 138 KV	TBD	TBD
	3513	WEC	NLK GENEVA TAP-SUGAR CR 138 KV	TBD	TBD
	3514	WEC,UPPC	NORDIC-PERCH LAKE 138 KV	TBD	TBD
	3515	WEC	JEFFERSON-LAKEHEAD 138 KV	TBD	TBD
x	3517	WEC	ARCADIAN-GRANVILE 345 KV	MISO	MISO
	3518	WEC	BUTLER-GRANVILE+ARCADIAN-GRANVILE	TBD	TBD
	3519	WEC	BUTLER-GRANVILE+WEMPLETOWN-PADDOCK	TBD	TBD
	3520	WEC	Merril-Hil 138 for Wemp-Paddock 345	TBD	TBD
	3522	WEC	Albers-Paris138 for Wemp-Padock 345	TBD	TBD
	3523	WEC	Stiles-Pioneer 138 for N.Appl-WhiteClay138	TBD	TBD
	3524	WEC	Ellington-Hintz + N.Appleton-Rocky Run 345	TBD	TBD
	3525	WEC	Stiles-Amberg 138 for Morgan-Plains 345	TBD	TBD
	3526	WEC	Arcadian TR 345-138 for Arcad-Gran	TBD	TBD
x	3527	WEC	PleasPr-Racine 345 for Wemp-Pad 345	MISO	MISO
	3528	WEC	N Appleton-Wh Clay 138 for Stiles-Pulliam 138 #64451	TBD	TBD
x	3529	WEC,WPS	N. Appleton-Rocky Run 345kV	MISO	MISO
	3530	WEC	Jeffrsn-LakehdCam138 Col-SFL345	TBD	TBD
	3531	WEC	WhtWater-Mukwanago138 Roe-Jeff138	TBD	TBD
	3532	WEC	Ellington-Hintz 138 for N.Appleton-Rocky Run 345	TBD	TBD
	3533	WEC	Whitewater-Mukwonago 138 for SFL-Columbia 345	TBD	TBD
x	3534	WEC	Kenosha-Albers 138 for Wempletown-Paddock 345	MISO	MISO
	3535	WEC	N.Appleton-LostDauphin 138 for Kewaunee 345-138 TR	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3536	WEC	N.Appleton 345/138 T1 for N.Appleton 345/138 T3	TBD	TBD
x	3537	WEC	Kenosha-Lakeview 138 for PleasPr-Zion 345	MISO	MISO
	3538	WEC,WPS	Pulliam4-Stiles 138 (flo) Pulliam5-Stiles 138	TBD	TBD
	3539	WEC	VALLEY-HAYMKT 138+GRANVL1-ARCADN1 345	TBD	TBD
	3540	WEC	VALLEY-HAYMKT 138+BLUMND3-OC CRK7 230	TBD	TBD
	3541	WEC	VALLEY-HAYMKT 138+BLUMND5-OCONNR-6 138	TBD	TBD
	3542	WEC	Amberg-Plains 138 flo Morgan-Plains 345	TBD	TBD
	3543	WEC	Granville-Swan 138 flo Saukville 345/138 Tr 1	TBD	TBD
	3544	WEC	Stiles-Amberg 138 & Stiles-Crivitz 138 flo Morgan-Plains 345	TBD	TBD
	3545	WEC	Amberg-Plains138 FLO Now Tap-Amberg138	TBD	TBD
	3546	UPPC, WEC	Cedar-National138 FLO Cedar-Tilden138	TBD	TBD
	3547	WEC	Granville 345-138 Xfr FLO Wempletown-Paddock345	TBD	TBD
	3548	WEC	Lakehead-Haiwatha 138kV 32.9	TBD	TBD
	3549	WEC	N.Appleton-LostDauphin138 (flo) Kewaunee-East Krok 138	TBD	TBD
	3550	WEC	N.Appleton-WhiteClay138 FLO Stiles-Pulliam138	TBD	TBD
	3551	WEC	N.Appleton 345-138 T1 FLO N.Appleton 345-138 T2	TBD	TBD
	3552	WEC	N.Appleton 345-138 T2 FLO N.Appleton 345-138 T1	TBD	TBD
	3553	WEC	N.Appleton 345-138 T2 FLO N.Appleton 345-138 T3	TBD	TBD
	3554	WEC	N.Appleton 345-138 T3 FLO N.Appleton 345-138 T2	TBD	TBD
	3555	WEC	Plains-Amberg138 FLO Now Tap-Amberg138	TBD	TBD
	3556	WEC	Plains-Amberg138 FLO Morgan-Plains345	TBD	TBD
x	3557	WEC	PleasPrairie-Arcadian138 FLO PleasPrairie-Racine345	MISO	MISO
x	3558	WEC	PleasPrairie-Arcadian345 FLO Zion-Arcanian345	MISO	MISO
	3559	WEC	Stiles-Crivitz115 FLO Morgan-Plains345	TBD	TBD
x	3560	WEC	Whitewater-Mukwonago FLO CherryVal-SilvrLk345	MISO	MISO
	3561	WEC	Whitewater-Mukwonago138 FLO Univer 93.6	TBD	TBD
	3562	WEC,MECS	McGulpin-Straits138 ckt. 3 FLO ckt. 1	TBD	TBD
	3563	WEC, WPS	N.Appleton-LostDauphin138 FLO N.Appleton-Mason St138	TBD	TBD
	3564	WEC,MECS	McGulpin-Straits138 ckt. 1 FLO ckt. 3	TBD	TBD
	3565	WEC	Paris-Burlington 138 (flo) Wempletown-Paddock 345	TBD	TBD
	3566	WEC	N Appleton-Wh Clay 138 flo Stiles-Pulliam 138 #64441	TBD	TBD
	3567	WEC	Flow South	TBD	TBD
	3568	WEC	Amberg-Stiles 138 flo Plains-Morgan 345	TBD	TBD
	3569	WEC	ATC Flow North	TBD	TBD
x	3570	WEC, CE	Pleasant Prairie-Zion 345 flo Cher 125.7	PJM	PJM
x	3571	WEC, CE	Pleasant Prairie-Zion 345 flo Zion-Arcadian 345	PJM	PJM
x	3572	WEC, CE	Pleasant Prairie-Zion 345 flo Zion-Arcadian 345 + Op Guide	PJM	PJM
	3573	WEC, MECS	Straits-McGulpin 138 #1 flo Straits-McGulpin 138 #3	TBD	TBD
	3574	WEC, MECS	Straits-McGulpin 138 #3 flo Straits-McGulpin 138 #1	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3575	WEC	Center-Fiebrantz 138 flo Arcadian- 113.8	TBD	TBD
	3576	WEC	Center-Fiebrantz 138 flo Wempletow 95.7	TBD	TBD
	3577	WEC	Center-Fiebrantz 138 (flo) Arcadia 172.0	TBD	TBD
	3578	WEC	Albers-Paris 138 (flo) Pleasant Prairie-Racine 345	TBD	TBD
	3579	WEC	Stiles-Pioneer 138 (flo) White Clay-Morgan 138	TBD	TBD
	3580	WEC,WPS	White Clay – Morgan 345kV (flo) Stiles – Pulliam 138kV	TBD	TBD
	3581	WEC	Stiles – Pulliam 138kV (flo) White 117.4	TBD	TBD
x	3601	ALTE,WPS	ARPIN – ROCKY RUN 345 KV	MISO	MISO
x	3602	WPS,WEC	ROCKY RUN – N APPLETON 345 KV	MISO	MISO
x	3604	WPS,ALTE	N FOND DU LAC-AVIATION 138 KV	MISO	MISO
	3605	WPS,WEC	MASON ST – N APPLETON 138 KV	TBD	TBD
	3606	WPS,WEC	HIGHWAYV – ROCKLAND 138 KV	TBD	TBD
	3607	WPS	HIGHWAYV – PREBLE 138 KV	TBD	TBD
	3608	WPS	WHITING AVE. – HOOVER 115 KV	TBD	TBD
	3609	WPS	ROCKY RUN-WESTON 345 KV	TBD	TBD
	3611	WPS	KEWAUNEE 345/138 XFMR	TBD	TBD
	3612	WEC,WPS	N APPLETON-FITZGERALD 345KV	TBD	TBD
	3613	WPS	KEWAUNEE XFMR+KEWAUNEE-N APPLETON	TBD	TBD
	3614	WPS	ROCKY RUN-WHITING AVE 115KV	TBD	TBD
	3615	WPS	ROCKY RUN-NORTHPT 115KV	TBD	TBD
	3616	WPS	WESTON-KELLY 115KV	TBD	TBD
	3617	WPS	HIGHWAYV-PREBLE+N APPLTN-WHITE CLAY	TBD	TBD
	3618	WPS	HIGHWAYV-PREBLE+N APPLTN-MASON ST	TBD	TBD
	3619	WPS	Kewaunee 345/138 for PtBeach-N.Appleton 345	TBD	TBD
	3620	WPS	RockyRun-Whiting115 FLO N.Appleton-RockyRun345	TBD	TBD
	3621	WPS	Whiting-Hoover115 FLO N.Appleton-RockyRun345	TBD	TBD
	3622	WPS	Weston 345-115 T1 FLO RockyRun 345-115 T1	TBD	TBD
	3623	WPS, WEC	Kewaunee-N.Appleton xfmr FLO N.Appleton-PtBeach345	TBD	TBD
	3624	WPS, WEC	Kewaunee-PtBeach345 FLO N.Appleton-PtBeach345	TBD	TBD
	3625	WPS, ALTE	Cranberry Loop 115kV	TBD	TBD
	3626	WPS	Lost Dauphin-Red Maple 138 flo Kewaunee-East Krok 138	TBD	TBD
	3627	WPS	Depere-Glory Rd 138 flo Kewaunee-E.Krok 138	TBD	TBD
	3628	WPS	Neevin-Butte de Morte 138kV FLO Fitzgerald 345/138 xfmr	TBD	TBD
	3629	WPS	N. Fond du Lac-Aviation 138kV FLO Fitzgerald 345/138 xfmr	TBD	TBD
	3630	WPS	Rocky Run-Weston 115 flo Rocky Run-Weston 345	TBD	TBD
	3631	WPS	Highway V – Preble 138 (flo) Lost Dauphin – Red Maple 138	TBD	TBD
	3701	ALTW	Poweshiek-Reasnor 161 kV	TBD	TBD
	3702	ALTW	Poweshiek-Reasnor 161 flo Arnold-Hazleton 345	TBD	TBD
	3703	ALTW	Poweshiek-Reasnor161 for Arnold-Tifften	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
Under Discussion	3704	ALTW	Poweshiek-Reasnor 161 for Montezuma-Bondurant 345	TBD	TBD
x	3705	ALTW	Arnold-Hazelton 345 for Wemp-Paddock 345	MISO	MISO
x	3706	ALTW	Arnold – Hazleton	MISO	MISO
	3707	ALTW	Lore-Turkey River 161 (flo) Wempletown-Paddock 345	TBD	TBD
	3708	#N/A	Adams 345/161kV TR9	TBD	TBD
	3710	#N/A	Adams 345-161 for Adams-Hazleton 345	TBD	TBD
x	3711	ALTW	Albany 161-138 for Nelson-Cordo B 345	MISO	MISO
	3713	ALTW	Lakefield 345-161 for Byron-Adams 345	TBD	TBD
	3714	ALTW	Lakefield Jct.-Fox Lk 161 for Arnold-Hazelton 345	TBD	TBD
x	3715	ALTW,CE	Quad Cities-Rock Creek 345/MEC Cordova-Sub 39	PJM	PJM
x	3716	ALTW	Rock Creek 345/161 TR for Quad-Sub 91 345	MISO	MISO
	3717	ALTW	Rock Creek-Dewitt 161 Quad Cities-Sub91 345	TBD	TBD
	3718	ALTW	RockCreek-Dewitt 161 for meccord3-sub39 345kV	TBD	TBD
x	3719	ALTW	Salem 345/161 Quad Cities-Sub 91	MISO	MISO
x	3720	ALTW	Salem 345/161 TR for MEC Cordova-Sub 39 345kV	MISO	MISO
x	3721	ALTW	Salem 345/161 for Quad-Sub 91 TR	MISO	MISO
x	3723	ALTW	Tiffon-D.Arnold 345 for Hills-Montezuma 345kV	MISO	MISO
	3724	ALTW	Arnold-Vinton 161 for D.Arnold-Hazleton 345	TBD	TBD
	3725	ALTW	Sub 56(Davnprt)-E.Calamus161 for Q 141.3	TBD	TBD
	3726	ALTW	Ames-BooneJct 115 for Montezuma-Bo 6.7	TBD	TBD
	3727	ALTW	Lakefield-Fox Lk 161 for Lakefield-LGS 345	TBD	TBD
	3728	ALTW	Dysart-Washburn 161 for D.Arnold-Hazleton 345	TBD	TBD
	3730	ALTW	Bondurant-BooneJct 161 for Lehigh- 106.3	TBD	TBD
	3731	ALTW	Lakefield Jct.-Fox Lake 161 flo Lakefield Jct.-Triboji 161	TBD	TBD
x	3732	ALTW	Arnold-Hazelton 345 (flo) Dorsey-Forbes 500	MISO	MISO
	3733	ALTW	Hazleton-Dundee 161 Eau Claire-Arpin 345	TBD	TBD
	3734	ALTW	E.Calamus-Calamus 115 for Arnold-Tiffin 345	TBD	TBD
	3735	ALTW,WAUE	Wisdom-Triboji 161 flo Raun-Lakefield 345	TBD	TBD
x	3736	ALTW	Salem 345/161 flo Wempletown-Paddock 345	MISO	MISO
	3737	ALTW	Hills 345/161 Xfmr flo Tiffin-Duane Arnold 345	TBD	TBD
	3738	ALTW	8th St-Lore 161 flo Wempletown-Paddock 345	TBD	TBD
	3739	ALTW	8th St.-Lore 161 flo Arnold-Hazleton 345	TBD	TBD
x	3740	ALTW,CE	Albany-Garden Plain 138 flo Quad Cities-H471 345	PJM	PJM
	3741	ALTW	Marshalltown-Fernald 115 (flo) Mon 52.7	TBD	TBD
	3742	ALTW	Lime Creek-Emery 161 flo Lehigh-Webster 345	TBD	TBD
	3743	ALTW	Lore-Turkey River 161 flo Wempletown-Paddock 345 + Op Guide (Summer-only)	TBD	TBD
	3744	ALTW	Vinton-Dysart 161 flo Arnold-Hazelton 345	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	3745	ALTW	Lime Creek-Emery 161 flo Adams-Hazleton 345	TBD	TBD
	3746	ALTW	Salem-Julian Center 161 (flo) Wempletown-Paddock 345	TBD	TBD
	3747	ALTW	Lakefield-Fox lake 161 (flo) Lakefield-Wilmarth 345	TBD	TBD
	3748	ALTW,MEC	Reasnor 161-Des Moines (flo) Monte 93.5	TBD	TBD
x	3749	ALTW	Arnold-Hazelton 345 (flo) Montezuma-Bondurant 345	MISO	MISO
	5008	CSWS	CraAshValLyd	TBD	TBD
	5014	CSWS	ElkXfrTucOku	TBD	TBD
	5017	OKGE	FTSXFR500345	TBD	TBD
	5021	OKGE,WR	KilCreWooWic	TBD	TBD
	5022	KCPL,WR	LacNeoLanWic	TBD	TBD
	5023	KCPL	LacStiLacWgr	TBD	TBD
	5035	KCPL,AECI	MontroClintn	TBD	TBD
	5037	OKGE,CSWS	MusClaMusRss	TBD	TBD
	5050	MPS,KCPL	StjLakIatStr	TBD	TBD
	5051	SPA,AECI	StockMorgan	TBD	TBD
	5052	SPA,AECI	StoMorLacNeo	TBD	TBD
	5053	SPA,AECI	StoMorMorBrk	TBD	TBD
	5063	CSWS	NesOneNesTul	TBD	TBD
	5076	OKGE	FtSmthANOVlt	TBD	TBD
	5077	OKGE,WR	CreKilWicWoo	TBD	TBD
	5085	CSWS	DanMagAnoFts	TBD	TBD
	5090	CLEC,CSWS,EES	DolXfrEldXfr	TBD	TBD
	5099	CSWS,OKGE	PitSemPitSun	TBD	TBD
	5100	SPS	PriSpePriSpe	TBD	TBD
	5194	OKGE	FTSXFR345161	TBD	TBD
	5196	SPS	SPS North – South	TBD	TBD
	5200	KCPL	LacWgrLacSti	TBD	TBD
	5204	WR	SphWmcSumEmc	TBD	TBD
	5207	OKGE	RedArcRedArc	TBD	TBD
	5214	OKGE	WdrCimSprNrw	TBD	TBD
	5215	CSWS	ValLydEldLon	TBD	TBD
	6001	WAUE,OTP,NSP,MP	NDEX	TBD	TBD
	6002	MHEB,WAUE,NSP	MHEX_S	TBD	TBD
	6003	WAUE,MHEB,NSP	MHEX_N	TBD	TBD
	6004	ALTE,WEC,WPS,NSP	MWSI	TBD	TBD
	6006	NPPD	GGS	TBD	TBD
	6007	NPPD	GENTLMN3 345 REDWILO3 345 1	TBD	TBD
	6008	NPPD	GRIS_LNC	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
x	6009	NPPD,MPS,AECI,OPPD	COOPER_S	MAPP	MISO
	6012	NSP,SMP	PRI-BYN	TBD	TBD
	6013	NSP	LKM-WFB	TBD	TBD
	6014	OPPD	FTCAL_S	TBD	TBD
	6015	DPC,NSP	ROCHSTR-ALMA / KING-ECL	TBD	TBD
	6017	SMP,ALTW	LAKEFIELD XFMR / BYRON-ADAMS	TBD	TBD
	6018	OTP,WAUE	CENTER – HESKETT 230	TBD	TBD
	6019	OTP	CENTER – JAMESTOWN 345	TBD	TBD
	6021	NPPD	ENDERS-BEVERLY / GENTL-REDWIL	TBD	TBD
	6022	NPPD	GRISLD-YORK / GRISLD-MCCOOL	TBD	TBD
	6023	NPPD	N.PLATTE-STVL /GENTL-REDWIL	TBD	TBD
	6024	NPPD	RED WILLOW – MINGO	TBD	TBD
	6026	WAUE	JMSTN-FARGO 1 AND JMSTN-FARGO 2	TBD	TBD
	6029	NSP,SMP	ROCHESTER-SILVER LAKE/PRI-BYRON	TBD	TBD
	6030	NPPD,OPPD	Nebraska City-Cooper 345kV	TBD	TBD
	6031	NPPD	GrandIsl-Aurora-Pauline-MarkMoore345kV	TBD	TBD
	6034	MEC,NPPD	RAUN-TEKAMAH 161KV	TBD	TBD
	6056	OTP,WAUE	JMS-PIC JMS-FARGO 1&2 FLO CEN-JMS]	TBD	TBD
	6057	MEC	Sub T-Hills 345kV FLO Sub 93-Sub 92 345kV	TBD	TBD
	6059	NSP,SMP	Silver Lake-Rochester 161kV FLO Byron-Pleasant Valley 345kV	TBD	TBD
	6060	MHEB,NSP	D602F 500KV	TBD	TBD
	6061	MHEB,NSP	R50M 230KV	TBD	TBD
	6062	SMP,NSP	Cascade Creek – Crosstown 161 (flo) King – Eau Claire	TBD	TBD
	6069	DPC,NSP	Alma – Wabaco 161kV (flo) Eau Claire – Arpin 345kV	TBD	TBD
	6072	MHEB	L20D 230kV	TBD	TBD
	6073	MEC,WAUE	Morningside-Plymouth 161kV FLO Raun-Sioux City 345kV	TBD	TBD
x	6074	MEC	Sub 91 345/161kV XFMR FLO Sub 91-Sub 56 345kV	MAPP	MISO
x	6081	MEC	Quad City West 345kV	MAPP	MISO
	6082	#N/A	SUB 92-HILLS FOR LOSS OF LOUISA_SUB T	TBD	TBD
	6083	NSP,SMP	Cascade Creek-Crosstown 161kV FLO Byron – Pleasant Valley 345kV	TBD	TBD
x	6084	MEC	East Moline 345/161 XFMER (flo) Quad Citites – Sub 91	MAPP	MISO
	6085	DPC	Genoa-Coulee FLO Genoa-LaCrosse-Marshland 161kV	TBD	TBD
x	6086	MEC	Montezuma-Bondurant 345kV	MAPP	MISO
	6087	NSP,SMP	Cascade Creek-Crosstown 161kV flo Adams Tramsformer 345/161kV	TBD	TBD
x	6088	DPC,NSP	Genoa-Seneca (flo) Eau Claire-Arpin	MAPP	MISO
	6089	NSP,SMP	Cascade Creek – IBM FLO Byron – Adams	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	6102	MPS	St. Joe – Midway 161kV 88.8	TBD	TBD
	6104	MPS	Iatan – St. Joe 345kV	TBD	TBD
x	6105	ALTW,CE	Quad Cities – Rock Creek	PJM	PJM
	6108	ALTW, DPC	TURKEY RVR-CASSVILLE FLO WEMP-PADDOCK	TBD	TBD
	6110	GREN	McHenry-Ramsey 230 FLO Center-Jamestown 345kV	TBD	TBD
	6111	NPPD,WAUE	GRAND ISLAND XFMR FLO GRAND ISLAND	TBD	TBD
	6112	SMP	Byron-Maple Leaf 161 flo Byron-Pleasant Valley 345	TBD	TBD
	6113	SMP	Byron-Maple Leaf 161 flo Pleasant Valley-Adams 345	TBD	TBD
	6114	DPC	Wabaco-Alma 161 flo Prairie Island-Byron 345	TBD	TBD
	6115	MPS	St. Joe-Midway 161kV flo St. Joe-F 103.5	TBD	TBD
	6116	DPC	Alma-Elk Mound 161 kV flo King-Eau Claire 345kV	TBD	TBD
x	6117	MEC	Sub 92-Hills flo Sub 93-Sub T-Hills	MAPP	MISO
	6118	MEC	Sub 93-Sub 31T flo Quad-Rock Ck 345	TBD	TBD
	6119	NSP	Adams 345/161 Xfmr flo King-Eau Claire Arpin 345	TBD	TBD
	6120	MHEB,WAUE	Glenboro – Rugby 230 kV	TBD	TBD
	6122	MEC	Council Bluffs-Avoca 161kV flo Council Bluffs-Madison County 345kV	TBD	TBD
	6123	MEC	Raun-Sioux City 345kV flo Raun-Lakefield 345kV	TBD	TBD
x	6124	MEC,ALTW	Sub K/Tiffin-Arnold 345kV	MAPP	MISO
	6125	MEC,OPPD	S1226-Tekamah 161kV flo Neal Gener	TBD	TBD
	6126	MEC,OPPD	S1226-Tekamah 161kV flo S3451-Raun 345kV	TBD	TBD
	6127	LES,OPPD	Sub 1214-70th & Bluff 161kV flo Cooper-Nebraska City 345kV	TBD	TBD
	6128	MEC,WAUE	Morningside-Plymouth 161kV flo Raun-Sioux City 345kV	TBD	TBD
	6129	MHEB,NSP,MP	Forbes-Chisago 500kV	TBD	TBD
	6130	NSP,WAUE	Granite Falls-Minnesota Valley 230kV	TBD	TBD
	6131	NSP	King-Eau Claire 345kV	TBD	TBD
	6132	NSP,SMP	Prairie Island-Red Rock #2 345kV flo Prairie Island-Byron 345kV	TBD	TBD
x	6136	CE, MEC	Quad Cities-Sub 91 345 flo Quad Cities-Rock Creek 345	PJM	PJM
	6137	ALTW, DPC	Turkey River-Cassville 161 flo Wempletown-Paddock 345 + Op Guide (Summer-only)	TBD	TBD
	6138	MHEB,WAUE	Glenboro – Rugby North 230kV	TBD	TBD
	6139	WPEK	Judson Large-Greensburg 115kV (flo) Spearville-Mullergren 230kV	TBD	TBD
	6140	WPEK	Medicine Lodge Transformer 138/115	TBD	TBD
	6141	WPEK	Sun City-Medicine Lodge 115	TBD	TBD
	6143	WAUE	Leland Olds KV2A 345/230 for Leland Olds KV1A 345/230	TBD	TBD
	6144	NSP,ALTW	Lakefield – Lakefield Gen 345kV	TBD	TBD
	6145	MPS	Lake Road-Nashua 161 flo Iatan-Stranger Creek 345kV	TBD	TBD
	6146	MEC,NPPD,OPPD	Tekamah-Raun 161kV flo Sub 3451-Raun 345kV	TBD	TBD
	6147	OPPD	Sub 3451-Raun 345kV	TBD	TBD

Reciprocal with PJM	Flowgate ID	Host Control Areas	Description	Owner	Manager
	7004	NYIS	CENTRAL – CAPITAL	TBD	TBD
	7101	IMO	BLIP-(Buchanan Longwood Input)	TBD	TBD
	7102	IMO	QFW-(Queenston Flow West)	TBD	TBD
	7104	IMO	NEGATIVE_BLIP(Negative Buch Lgwd Input)	TBD	TBD
	11883	#N/A	Miami Fort 345/138 Xfmr 9 (flo) Zimmer Unit 1	TBD	TBD
	2969	#N/A	Miami Fort 345/138 Xfmr 9 (flo) Jefferson-Hanging Rock 765	TBD	TBD
	2970	#N/A	Miami Fort 345/138 Xfmr 9 (flo) Rockport-Jefferson 765	TBD	TBD
	2971	#N/A	Smith-Hardin Co 345 (flo) Ghent-West Lexington 345	TBD	TBD
	2972	#N/A	Newtonville-Cloverport 138 (flo) Wilson-Green River 161	TBD	TBD
	6148	#N/A	Genoa-LaCrosse-Marshland flo Genoa-Coulee	TBD	TBD
	6149	#N/A	Raun-Sioux City 345KV	TBD	TBD

Appendix G – Issues and Resolutions

The table on the following pages contains a comprehensive list of issues and questions that were identified from the following sources:

- MISO/PJM/SPP website comments
- MISO/PJM Seams Stakeholders meetings
- NERC OC Meetings
- NERC MISO/PJM Review Team Meetings
- Regional Meetings

The table attempts to list each issue that has been raised, and direct the reader to the documentation where the issue is addressed – or explain why it was not.

ISSUE	DOCUMENTATION/COMMENTS
1. Parallel Flows	
1.1. Congestion Management Procedures	
1.1.1. Why are Market Flows being split into only priorities 6 and 7 of the NERC curtailment priorities.	-All Market Flows within PJM and MISO would be are under their single, respective tariffs – and therefore candidates for Priority 6, network service or Priority 7, Firm. However, the proposal was enhanced to Prioritize flows committed same day to be Priority 2, non-firm hourly for those Flowgates where owners agreed to a reciprocal coordination agreement.
1.1.2. Define steps that will be taken (redispatch first, TLR non-firm second, TLR firm third etcetera) for PJM, MISO, and 3rd party Flowgates.	-This is covered in new section "Process to Respect Flowgate Capabilities"
1.1.3. Tagging in, out, or across markets – are MW impacts properly accounted for?	Interchange transactions are tagged back to marginal units per proposal to provide better granularity than today.
1.1.4. Do Market Flows include transactions in, out, or across market or only all Control Zones NNL plus inter Control Zone flows?	- Market Flows include all flows caused by generators in the market that are not tagged and provided to NERC IDC. Grand-fathered internal transactions are tagged and interchange transactions in, out or across the market will be tagged.
1.1.5. IDC modeling vs LMP modeling of Flowgate impacts	- This proposal provides the mechanism to quantify, prioritize, and marry LMP market impacts on Flowgates to the Tariff priorities in the IDC. The real-time modeling provided by the LMP systems will greatly enhance overall granularity of the IDC.

ISSUE	DOCUMENTATION/COMMENTS
1.1.6. Creation of Flowgates on the fly.	-“Process to Develop Flowgates on the Fly” is provided in this document.
1.1.7. Communications of curtailments back to RCs	-Communication of curtailments through same channels as used today – NERC IDC.
1.1.8. Are generators that are within PJM but not part of the market included in calculating the “Market Flows”?	- Yes, all flows caused by generators in the market will be included in the market flow calculation. The market flow calculation is adjusted for tagged flows so double counting doesn’t occur.
1.1.9. Multiple relief requests, how calculated?	- Once it is determined relief is needed on a Flowgate and that TLR will be used, the Multiple relief requests will be handled sequentially as it is today in the IDC.
1.1.10. Explain calculation of Market Flows	-“Defining Monitored Flows” this document
1.1.11. Market Flow Calculation engine:	-RTO State Estimator/LMP engine will be used for accuracy.
1.1.11.1. LMP (pros/cons?)	- Robust, real time, and well maintained model that is also used to set LMP prices. Granularity down to the real time output of generators and actual load will provide greater accuracy. RTOs need ability to quantify flows/impacts outside IDC to enable RTO to RTO, Market to Market congestion management outside IDC to achieve greater efficiencies without calling TLRs.
1.1.11.2. NERC IDC (pros/cons?)	- Less accurate without major enhancements. Duplicative with RTO requirements for models needed to run markets.
1.1.11.3. Industry oversight of calculations – IDCWG or DFWG? Auditable, repeatable, verifiable calculations?	- RTOs will provide mechanism for NERC to audit calculations. See Appendix K.
1.1.11.4. Synchronicity of models	- Achieved through use of real time ICCP/ISN data for observable areas of market and with SDX data for outlying areas.
1.1.12. Why isn’t the real-time shift of generation under market operations (or more specifically the difference between the day-ahead market dispatch and the real-time dispatch) not being treated similar to non-firm redirects in the hourly market.	- Will be considered non-firm hourly priority with parties willing to reciprocate actions
1.1.13. NNL Calculation:	-“Calculation of NNL” this document
1.1.13.1. Real time – for real time, will PJM be getting 5 second scans? Every 6 minutes? What is the scan-rate?	- Will provide Market Flows to IDC at least every 15 minutes (as requested by OATI and the IDCWG, the RTOs could provide updates as often as every 5 minutes.

ISSUE	DOCUMENTATION/COMMENTS
1.1.13.2. Will the market flow methodology be used to determine the market flow impact on all Flowgates? Will MISO use the same methodology once their market is up? If not, what is the guarantee that comparability will be achieved?	- Will be used for all Coordinated Flowgates as defined in paper. MISO and PJM will use same methods when MISO's market starts and PJM expands.
1.1.13.3. In your (PJM's) realtime model, you are going to run sensitivity studies. How far do your model(s) go out? Are they robust enough to capture flows/impacts in Michigan? Wisconsin? Missouri?	- In order to model the Coordinated Flowgates, PJM EMS model will grow from a 7,000 bus model to a 24,000 bus model. As such, PJM is very confident that its model will be more than robust enough to capture all of its flows on each of the Coordinated Flowgates it impacts.
1.1.13.4. Display "timeline" of this process.	- See examples.
1.1.13.5. How to calculate NNL service for new network resources (e.g., generators)	- MISO and PJM will use existing processes to designate new network resources.
1.1.14. Tagging Issues and Solutions:	
1.1.14.1. Would the IDC ignore those transactions/tags in, out, and through PJM regarding the market coordination Flowgates as they relate to calculating distribution factors and/or impacts in lieu of the values submitted by PJM	-All tag impacts will be calculated/ represented by the IDC just as they are today – regardless of whether viewing a coordination Flowgate or other Flowgate. MISO and PJM will, however, provide better information to IDC as to the source or sink of those transactions.
1.1.14.2. If using the marginal generator to calculate the distribution factors, how would the IDC be aware of the marginal generator?	-Marginal units within PJM and MISO will be communicated to IDC in the form of generation participation factors
1.1.14.3. Why would it be advantageous for the RTO to calculate TDFs vs the IDC?	- This concept was is earlier draft proposal and is no longer being pursued Additionally, both the NERC MISO/PJM Review Team and NERC OC endorsed the concept of the RTOs making these calculations.

ISSUE	DOCUMENTATION/COMMENTS
1.1.14.4. How determined what of Market Flow impacts will be considered 6NN and what will be considered 7-F	See Sections 5 and 6.
1.1.14.5. How to avoid double-counting Firm pt-pt schedules	- Process provides method so “partial path reservations” are not double counted.
1.1.14.6. How will you synchronize timing of MISO and PJM flow calculations (every five minutes) with the IDC calculations?	- Calculations will be performed at least every 15 minutes at an agreed upon time.
1.2. ATC/AFC Coordination	
1.2.1. AFC calculation and consideration of external Flowgates	- MISO and PJM are offering to coordinate AFC/ATC calculations with any external parties wishing to do so. As per the Appendix on MISO/PJM AFC Coordination, the RTOs will each be respecting over 300 Flowgates external to their respective boundaries.
1.2.2. If your firm AFC calculations are based on day-ahead, how firm is day-ahead? If it is not extremely accurate, PJM’s firm Allocation could be taking up room on a Flowgate, while in reality the total MWs flowing current day may only be a fraction of the Allocation that was calculated day-ahead. This could result in keeping people off of Flowgates when there is in fact room on the Flowgate. And currently this could be done for free, because the PJM customer would not have to pay for it unless they used it.	AFC and NNL calculations will allocate firm room on Flowgates in advance to those parties participating in the reciprocal agreements to coordination firm/NNL on those Flowgates. Any unused Flowgate capabilities are released for non-firm near real time.
1.2.3. If there is any capacity left after MISO and PJM have made a determination, what is timeframe for making use of this capacity?	- Non-firm, Priority 6 is made available on a day-head basis and non-firm hourly is made for current day.
1.2.4. Define transmission Allocation/ entitlement	- Process to account for firm and no-firm commitments on Flowgates to help present over subscription of capabilities.
1.2.5. Need to make sure service is granted on the same basis it’s being curtailed.	- Service will be curtailed under the same priority as was granted. Location of source and sink generators are estimated when service is granted. Process provides for mapping service back to zones where generation will be adjusted should service be curtailed.

ISSUE	DOCUMENTATION/COMMENTS
1.2.6. When the market expands, will the market gain firm rights outside the market that they do not own currently? Why should a Control Area gain firm rights that they did not have before – simply because the market expands?	- No, default will be level of firm that they would have had if the market did not expand. If additional firm room is available, Reciprocal Entities that agree to do so will allocate reaming room to prevent over subscription. Additionally, the calculation of NNL permits the RTOs to enhance granularity of determining all of the economic impacts on external Flowgates so that the RTOs can aggressively respond to a TLR.
1.2.7. Are you considering every generator a separate designated resource for all PJM load?	- No, Designated Resources are designated to their customer load. For example, Designated Resources within ComEd that are designated for customer load in ComEd will only count for that load and not entire PJM load.
1.2.8. Define "Historic NNL"	- Process to quantify the firm capabilities, for both network service and point-to-point inside the market, Control Area by Control Area that entities would have had if markets did not start or expand. "Historic" refers to historic or present process to quantify those values but does not refer to the level of firm for some past period.
1.2.9. How would you consider external transactions?	- They will be tagged and consider same as today. However, this proposal provides far more granularity to where actual generators will be moving to support schedule changes (this granularity will be in the form of the list of real-time marginal units).
1.2.10. Is there any coordination on non-firm?	See Sections 5 and 6
1.2.11. Loop flows are still not being accounted for. Therefore, if you calculate the ATC/AFC without accounting for loop flows, won't you oversell the Flowgate?	- Loop flows are estimated and accounted for in processed to help minimizing overselling of the Flowgates.
1.2.12. Need to work out a means for 6NN within PJM to be considered 6NN within MISO, and visa versa.	- Per suggestion of Stakeholders, process is provided to account for Priority 6-NN among all Reciprocal Entities.
1.2.13. In the day-ahead commitment, you (Tom Bowe) said that you will respect the NNL limits as related to the list of Flowgates that you agree on. Won't this falsely limit PJM?	The final draft of the Whitepaper, provides clarification to this question. The RTOs will not bind the Coordinated Flowgates to the NNL value unless the outage coordination and recent TLR activity show the need to limit the Flowgate in the day ahead commitment. The RTOs will further restrict their reciprocal Flowgates to respect one another's anticipated dispatches and schedules.

ISSUE	DOCUMENTATION/COMMENTS
1.2.14. Once an "Allocation of usage" of a Flowgate is determined by MISO and PJM, when additional parties come into the mix in the future (Duke), won't the Allocations have to be re-negotiated/re-calculated?	- Allocations may be recalculated if additional parties wish to join reciprocal process. Same process will be utilized to determine new parties' base usage and "Historic NNL".
1.2.15. If someone wants to purchase transmission for this summer, how will this be handled both before transition and after? How will existing purchased transmission be handled during the "transition"?	For this summer, same as today.
	Transmission service within a market will be converted and utilized according to that market's rules.
1.2.16. Complete and post the ATC/AFC Coordination agreement.	- ATC/AFC Coordination Agreement is an appendix of this paper.
1.2.17. Explain process of AFC Coordination with third/outside parties?	- Any party that wishes to participate can.
1.2.18. Explain ATC coordination across the EI.	- Only those that agree to will participate in the MISO/PJM ATC. AFC Coordination. Outside of that, different processes are used.
1.2.19. Explain conversion of grandfathered firm pt-pt	- grand father firm pt-to-pt will be converted per market rules where they apply or may remain same service and be tagged as today.
2. Contract Tie Capacity	
2.1. One Stop Shopping	- Out of scope of this process
3. Different Definitions/Procedures between RTOs	
3.1. Emergency & Restoration Procedures	Emergency & Restoration Drills held 11/02
3.2. Operating Procedures for Voltage Collapse & Stability	-Included in Attachment A of MISO & PJM Reliability Plans
4. NERC Regional Criteria and Reserve Sharing	
4.1. Define NERC Operating Policy changes, waivers, or certifications that are needed to permit security-constrained dispatch over multiple existing Control Areas and to allow flows to not be tagged between Control Zones. Potential Policy 1, Policy 3, and Policy 9 changes may be required.	Wavers are requested from NERC for Policy 3 and Policy 9.
	Policy 3 – Waiver request permission for PJM and MISO to provide market flow impacts to IDC instead of providing information by E-Tags.
	Policy 9 –Waiver requested to permit prioritization and reduction of market flow impacts on same basis as tagged interchange transactions. Waiver also requests that Market Flows be calculated actual flows rather than only using positive flows of 5% impact or greater. Security Coordination.
4.2. How does a market entity (PJM or MISO) respond to Reserve Sharing events?	Methods will be similar as today and will be defined within each market's rules.
	Reserve Sharing is beyond the scope of this proposal to manage congestion.
4.2.1. Events with ECAR, only (former) ECAR CA's respond?	- This proposal respects and does not change reserve sharing pools and arrangements.

ISSUE	DOCUMENTATION/COMMENTS
4.2.1.1. Studies and transmission margin already in place to handle the transfer of energy across network to needing party	- MISO and PJM have agreed to coordinate TRM/CBM to allow reserves to flow when called upon.
4.2.2. Events within ECAR, all of the market entity (PJM or MISO) generation resources respond?	- This proposal respects and does not change reserve sharing pools and arrangements.
4.2.2.1. This could impact transmission facilities where a transmission margin and associated studies are non-existent and cause overloads or other problems not previously anticipated	- Existing reserve sharing groups are not changed by this proposal.
5. Facilities in Close Electrical Proximity under Different RTOs	
5.1. Outage Maintenance Coordination	- Procedure included as appendix of this document.
5.2. Access & Expansion Planning	- MISO and PJM have agreed to coordinate Access & Expansion Planning. Procedure will be documented by separate agreement.
6. Market flow calculation, reflect ISN and SDX data	- Yes, State Estimator results that are used to calculate Market Flows utilize ISN and SDX data. State Estimators use of real time ICCP/ISN data for observable areas of market and SDX data for outlying areas.
7. Control Area/Control Zone responsibilities?	-Control Area responsibilities haven't changed. However, market operator may perform some of the responsibilities.
	- Control Zones recognize former Control Area boundaries where the market operator performs many of the traditional Control Area responsibilities. Control Zone boundaries are utilized when calculating historic NNL in PJM.
8. GLDF calculation. GLDFs depend on where the load is located. What is the % threshold?	- For Market flow calculation, the load is the entire market. For Historic NNL calculation, the load is the former Control Area. Percent threshold is 0% in order to calculate actual impacts and not only positive impacts of 5% or more.
9. Regarding wide area dispatch and network resources to network loads, Not all loads in PJM are firm network loads. Resource deliverability?	True. Designated resources are designated to their customer load. For example, Designated Resources within ComEd that are designated for customer load in ComEd will only count for that load and not entire PJM load.
10. Will you keep former CAs in the model?	Yes. Only for the purposes of calculating historic NNL, and calculating projected flows between what was once the CA's so that RC's do not lose the information they need to conduct their day-ahead studies.

ISSUE	DOCUMENTATION/COMMENTS
11. Define coordination that will take place between the market entity (PJM or MISO) and the IDC	- MISO and PJM will input market impacts to IDC and will follow curtailment orders received by IDC.
11.1. Define necessary IDC changes	- IDC will be changed to allow Market Flows to be prioritized and uploaded to IDC and curtailed/redispatch on same basis as interchange transactions R-tagged and entered into IDC. MISO and PJM will also provide more granular information to IDC regarding to sources and sinks of interchange transactions flowing in or out of the markets. IDC changes are documented in NERC Change Order 114.
11.2. Will coordination include updates of network model base cases and the Book of Flowgates?	Yes.
12. Industry oversight of PJM impact calculations.	- MISO and PJM will provide audit process to NERC. See Appendix K.
12.1. IDC cost issue	- MISO and PJM will pay for changes needed to implement this proposal in IDC.
12.2. Cost Allocation.	- MISO and PJM split 50/50 NERC costs for changes needed to implement this proposal in IDC.
13. Contingency plans? Critical path analysis.	RTOs committed to reliability.
	Implementation will be delayed until ready.
	Approval of plans, completion of IDC changes, testing/training or processes in IDC training server.
14. Selection process of market/TLR Coordinated Flowgates	-Process/Criteria to Determine Flowgates in this document
14.1. FTR and ARR auction in PJM April, are these shared Flowgates going to be included in the auction	-Yes, immediately prior to market implementation
14.2. How is it determined those Flowgates the market has an effective control of	- Criteria to determine Coordinated Flowgates is used to identify Flowgates ahead of time that market will have effective control of its flow over. See Section XX
14.3. What if there are Flowgates that see a significant flow from the market but the market doesn't have an effective control	- Criteria should screen those out. However, market can pay market/entities outside it market to provide redispatch. MISO will pursue agreements with neighboring entities
14.4. Need to ensure criteria for selecting Flowgates includes all Flowgates actually and significantly impacted by Market Flows.	Agreed, goal of criteria is to identify and include such Flowgates.
	PJM has sent the list of 240+ Coordinated Flowgates to all interested parties. In the two+ months parties have had to review the process only two entities has provided feedback (for a total of 4 additional Flowgates)
14.5. 5% threshold doesn't correct parallel flow problem. Need MW % usage.	- Criteria allows for inclusion of significantly utilized Flowgates with less that 5% impact on a case-by-case basis.
14.6. On the 5% limit, in the study you are referring to, because of the magnitude of the market flow, even 3% of a large amount of energy could easily overwhelm a Flowgate. Why use the 5% threshold – just when coming up with the list of market coordination Flowgates?	Need to use a method to screen Flowgates so that Flowgates where market doesn't have effective control over are not included. For example, Market can't redispatch 1000 MW to remove 1 MW of flow.

ISSUE	DOCUMENTATION/COMMENTS
	5% threshold is needed to develop list of Flowgates because market impacts will be calculated down to 0% on those Flowgates. If 5% screen is not used, Flowgates may be included where market have very ineffective control.
14.7. Develop process where significantly impacted (ex. 20% of Market Flow) Flowgates may be added to list.	- Criteria allows for inclusion of significantly utilized Flowgates with less that 5% impact on a case-by-case basis.
14.8. Need to address how we phase in list of Flowgates based on Market Growth Timeline	Studies will be performed based on areas included in the market for each time frame.
	The List of Flowgates Appendix shows how the initial studies have shown how this list will incrementally grow to support the Market Growth timeline.
14.9. If there is disagreement, who will make the final determination of whether a particular Flowgate is or is not included?	- NERC Operating Reliability Subcommittee or NERC Operating Committee.
14.10. Why not perform a study on all Flowgates in the BOF – but not add them unless they are needed. Then the calculation would already have been completed.	- All Flowgates in NERC Book of Flowgates will be included in initial screening. Criteria for determining Flowgates are exhaustive. Need to have process to add Flowgates on the fly if new Flowgate, not already in the IDC, is needed.
14.11. Why is it so important to come up with a relatively finite list of Flowgates right now. Then attempt to add Flowgates in the future "on the fly".	Threshold is applied when defining list of Flowgates since market flow is calculated down to 0%.
	- Always need to be able to add Flowgates on the fly if new constraint, not in the IDC, is identified.
14.12. Why not just have the market entity send information to the IDC and let it calculate the market impact?	- More accurate and efficient for market entity to calculate flows. Will enable market to market coordination outside of IDC and TLR.
14.13. "We (PJM) will allow MISO to audit us and determine if our redispatch and calculations are accurate and effective."	- MISO will also allow PJM to audit calculations.
14.14. Will all studies and their results be made posted or made public?	- As appropriate respecting confidentiality requirements.
14.15. Are MISO and PJM only considering Flowgates for the list that are within MISO or PJM?	- The RTOs have determined many 3rd party Flowgates per criteria.
15. What happens when MISO Firm and NNL + PJM Firm + NNL + 3rd parties firm and NNL + TRM and CBM > TTC?	

ISSUE	DOCUMENTATION/COMMENTS
15.1. How will day-ahead processes reduce planned flows when oversubscribed?	- No mechanism to ratchet down oversubscribed flows day ahead. Many Flowgate may already be over subscribed, by the current transmission providers. Will conduct Next –Day Reliability Analysis to ensure reliable system next day and identify required actions. Will use real time processes to reduce flows as needed. Additional MISO/PJM AFC coordination may avoid oversubscription of some Flowgates.
16. Sunset Provision	
16.1. Why not implement a sunset date for these procedures of December 1, 2003 – or such time as MISO implements its Day 2 market.	- MISO will utilize these procedures to enable its market to start. Will build upon, enhance, and adjust these procedures as needed with proper approvals.
17. Seams Agreement needs to be completed	- MISO and PJM plan to have a Coordination Agreement, which will include seams agreements.
18. Interaction with ATCo's Attachment K	
18.1. Possible joint redispatch agreement between ATC (and the generators on ATC's system) and PJM?	-May be handled in market-to-market environment. Should PJM's market expansion be delayed, MISO will pursue agreements with neighboring generators to achieve more economical redispatch results.
19. Define "RTO Area Wide Dispatch"	- Market area wide central, security constrained dispatch of generation in market.
20. Parallel Flows are not being paid for	-Clearly a compensation issue that needs to go to FERC.
21. Historic NNL values should not be reflected indefinitely in the future, and an appropriate mechanism to rationalize the historic flows to recognize eventual market conditions should be developed	- Absolutely. A new mechanism will need to be designed.
22. Which of these processes will change or go away once MISO and PJM are both operating their full markets? Which ones will remain in place?	- These procedures will remain in place, be built upon, and enhance for the Market-to-Market Coordination.

Appendix H – Training

The concepts in these proposals should not have a significant impact upon System Operators beyond the Operators of the RTOs. The reason that this impact rests upon the RTOs is that the RTO Operators will need to be trained to monitor and respond to the external Flowgates.

RTO Operator Training Impacts include

1. The ability to recognize and respond to Coordinated Flowgates.
   a. IDC outputs will show schedule curtailments and possible redispatch requirements.
   b. Must be able to enter constraint in systems to provide the redispatch relief within 15 minutes
   c. Must be able to confirm that the required redispatch relief has been provided and data provided to the IDC.
2. Capability to enter Flowgates on the fly.

Other Reliability Coordinator (RC) System Operators Training Impacts include:

1. The ability to take projected net system flows between an RTOs Control Zones versus only tag data to run day-ahead analysis (data to be provided by the IDC).
2. Need to develop a working knowledge of how relief on a TLR Flowgate can come from both schedule changes and redispatch on a select set of Coordinated Flowgates.
3. Can coordinate with an RTO Operator when the RC System Operator has a temporary Flowgate that they believe requires the implementation of the "Flowgate on the Fly" process.

Appendix I – PJM/MISO Generation and Transmission Outage Coordination

PJM and MISO will jointly develop protocols for sharing transmission and generation outage schedule data. PJM and MISO agree to the following with respect to transmission and generation outage coordination:

Exchange of Transmission and Generation Outage Schedule Data

The projected status of generation and transmission availability will be communicated between the RTOs while respecting data confidentiality agreements. All available information regardless of scheduled date will be shared. PJM and MISO shall exchange the most current information on proposed outage information and provide a timely response on potential impacts of proposed outages.

PJM and MISO both have their own different outage scheduling applications. Ideally these applications should both be supplemented with a common process to automate the exchange of this information between the systems to minimize manual duplication of information and to assure that both RTOs have access to the same outage information.

Until this is accomplished, the RTOs will use email as the primary method to communicate new outage requests, and changes to outage requests, to the potentially impacted RTO that has indicated an interest in receiving the facility outage information. The potentially impacted RTO shall respond via email (and voice communication) and identify any proposed outage that is expected to impact the reliable economic operation within their RTO.

The RTO's agree that this information will be shared as soon as the information is available but at least daily and more often as required by system conditions. The RTOs shall jointly develop a common format for the exchange of this information. The information shall include (but not be limited to) owning RTO's facility name; proposed outage start date & time; proposed facility return date & time; date and time when a response is needed from the impacted RTO to modify the proposed schedule; and any other information that may be relevant to the reliability assessment.

Each RTO will also independently provide information on approved and anticipated outages formatted as required for the NERC SDX System.

Evaluation and Coordination of Transmission and Generation Outages

As described above, the RTOs will exchange transmission and generation outage data. Initially each owning RTO shall provide the other RTO a listing of facility names that they will use to identify the facilities in their footprint and the other RTO shall respond by identifying which facilities they are interested in receiving outage information about. Updated facility lists should be exchanged at least twice a year. The RTOs will also exchange lists of operations personnel involved in outage coordination and outage coordination procedures.

The RTOs will utilize network applications to analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each RTO's outage analysis will consider the impact of its critical outages on the other RTO's system reliability, in addition to its own.

On a daily basis, the Operations Planning staff of each RTO shall jointly discuss outages for potential impacts. These discussions should include an indication of either concurrence with the outage or identify significant impact due to the outage as scheduled. Neither PJM nor MISO has the authority to cancel the other party's outage (except RTO to RTO tie lines). However, the RTOs will work together to resolve any identified outage conflicts. Consideration will be given to outage submittal times and outage criticality when addressing outage conflicts. If outage analysis indicates unacceptable system conditions, the RTOs will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of such proposed maintenance. If an operating procedure cannot be developed and a change to the proposed schedule is necessary based on significant impact, the RTO's shall discuss the facts involved and make every effort to act on behalf of the other RTO to effect the requested schedule change. If this change cannot be accommodated, the RTO with the outage shall notify the impacted RTO. A request to adjust a proposed outage date must include, identification of the facility(s) overloaded, and identify a similar time frame of more appropriate dates/times for the outage to be successful.

The RTOs will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known. The RTO's will evaluate the impact of emergency and forced outages on the RTOs' systems and work with one another to develop remedial steps as necessary.

Outage schedule changes, both before or after the work has started, may require additional review. Each RTO will consider the impact of these changes on the other RTO's system reliability, in addition to its own. The RTOs will contact each other as soon as possible if these changes result in unacceptable system conditions and will work with one another to develop remedial steps as necessary.

Appendix J - PJM, MISO, and SPP ATC Coordination Document

Purpose and Background

On December 20, 1999, the Federal Energy Regulatory Commission (FERC) issued its ruling on the voluntary establishment of Regional Transmission Organizations (RTOs). This ruling, Order 2000, establishes a set of minimum characteristics and functions required of all RTOs. One of the functions required of RTOs by Order 2000 is Interregional Coordination. To fulfill this function, FERC requires that the RTO must ensure the integration of reliability practices within an Interconnection and market interface practices among regions. The integration of market interface practices among regions includes the coordination and sharing of data necessary for calculation of TTC and ATC, transmission reservation practices, scheduling practices, and congestion management procedures. The RTO is required to develop mechanisms to coordinate their activities with other regions. While it is not required to include the mechanisms at the time of RTO application, reporting requirements must be proposed by the RTO to provide follow-up details for how the RTO is meeting the coordination requirements.

Representatives from the former Alliance companies, Midwest Independent System Operator (MISO), and Southwest Power Pool (SPP) have been involved in a collaborative process to detail the data exchange requirements and mechanisms, data usage principles, and coordination of methodologies necessary to calculate TTC and ATC values for a seamless market interface.. This document describes the agreements reached to facilitate fulfillment of this specific coordination requirement imposed by Order 2000 on all RTOs. Subsequent to this process, a number of the former Alliance companies decided to join PJM. Therefore, PJM has become a party to this procedure.

I. Data Exchange

The vast Eastern Interconnection is highly integrated and capable of reliably transmitting energy over long distances. The operational control of this Interconnection is distributed among various transmission providers and Control Area operators. The localization of control is accomplished effectively on a regional basis by RTOs, which provide the direct supervision necessary to respond to transmission contingencies and operational emergencies in a swift and effective manner. Typically, these contingencies will impact the operation in the vicinity of the contingency. For example, the status of the transmission system in New England has very little impact on the operation of the transmission systems in the Mid-Continent and Southern regions. However, one should not conclude that each of these transmission systems can or should operate independently. Since the Eastern Interconnection connects all transmission systems within the Interconnection, the conditions within one region can impact the loadings, voltages and stability of others within the Interconnection. The magnitude of this impact is a function of generation status (including the generation serving specific loads), transmission configuration, and load level. Since the operation of one system will impact the operation of neighboring systems, data must be exchanged in order to maintain the reliability of the Interconnection.

The calculation of Total Transfer Capability and Available Transfer Capability is a forecast of transmission capacity that may be available for use by transmission customers. Such use also impacts the loadings, voltages and stability of neighboring systems. Because of this interrelationship, neighboring entities must exchange pertinent data in order for each entity to determine the TTC and ATC values for its own transmission system. This data is also necessary so that one RTO can refuse transmission service, if it is determined that the reservation request under consideration—if implemented—may overload facilities in the adjacent RTO.

The NERC SDX System currently is used to exchange statuses of generators rated greater than 150 MW, outages of all interconnections and other transmission facilities operated at greater than 230 kV, and peak load forecasts. This system has the capability to house daily data for the next seven days, weekly data for the next month and monthly data for the next year. Since this tool is currently being used and is maintained by NERC, the parties to this discussion believe that it would be prudent to use existing tools and methods as much as practical to accomplish the needed data tasks and avoid duplication of effort to the extent possible. Therefore the participating RTOs have agreed to fully populate the SDX System and update the data in the SDX System on a daily basis.

Therefore, the following data must be exchanged for each RTO to adequately determine its own TTC and ATC values and determine the impact of a proposed transmission service request on adjacent systems. Appendix A contains the procedural details of this data exchange.

Generation Outage Schedules from SDX

The projected status of generation availability over the next 13 months will be communicated between the RTOs using the existing NERC SDX System. The RTOs have agreed that this data will be updated at least daily for the full posting horizon and more often as required by system conditions. It is imperative that accurate and complete generation maintenance schedules are reflected in this data exchange. The RTOs have agreed that the ‘return date’ of a generator—either from a scheduled or forced outage— is necessary data for the determination of the TTC and ATC values. Therefore, each RTO has agreed that the generator availability data provided to the other RTOs will be the most current data available. If the status of a particular generator of less than 150 MW is used within an RTO's TTC/ATC calculation, the status of this unit shall also be supplied via the NERC SDX System.

Generation Dispatch Order

In addition to the availability status of each 'significant' generator in a neighboring RTO, the dispatch of the available generation is necessary to accurately model future transmission system conditions. Broad assumptions can be made concerning generation, such as scaling all available generation to meet the generation commitments within an area and then increasing all generation uniformly to model an export, or similarly uniformly decreasing all generation to model an energy import. Excluding nuclear generation or hydro units from this scaling would provide some level of refinement. It was agreed that this simplistic approach may not be adequate to identify transmission constraints and determine rational TTC/ATC values. On the other extreme, economic data could be shared to allow an economic dispatch to be determined for each level of generation commitment. It was recognized that this level of refinement was generally unnecessary, and the data will likely be considered confidential by the generation owners, and therefore unavailable. As a practical alternative, each RTO will provide each neighboring RTO a typical generation dispatch order or generation participation factors of all units on a Control Area basis. With this information, combined with the availability of the units as provided by the SDX System, a reasonably accurate dispatch can be developed as necessary for any modeled condition. The generation dispatch order would be updated as required by changes in unit statuses; however, it is envisioned that a new generation dispatch order would not be necessary more often than prior to each peak load season.

Transmission Outage Schedules from SDX

The projected status of transmission outage schedules over the next 13 months will be communicated between the RTOs using the existing NERC SDX System. The RTOs have agreed that these data will be updated at least daily for the full posting horizon and more often as required by system conditions. It is imperative that accurate and complete transmission facility maintenance schedules are reflected in this data exchange. The RTOs have agreed that the 'outage date' and 'return date' of a transmission facility (either from a scheduled or forced outage) are necessary data for the determination of the TTC and ATC values. Therefore, each RTO has agreed that the available data provided to the other RTOs will be the most current data available. If the status of a particular transmission facility operating at voltages less than 230 kV is critical to the determination of TTC and ATC of an RTO, the status of this facility would also be supplied via the NERC SDX System.

Transmission Interchange Schedules and Reservations

Schedules

The existing transmission reservations and interchange schedules of each neighboring RTO are also required to accurately determine the TTC and ATC values. Since interchange schedules impact the short-term use of the transmission system, the interchange schedules are necessary to determine the remaining capacity of the transmission system as well as determine the net impact of others' activities on the operation of each RTO. The resultant 'loop flow' has a direct impact on the amount of transmission service that can be accommodated by a transmission system. The parties have agreed that the interchange schedules will be made available to neighboring RTOs for their use. Because of the shear volume of this data, it may be more practical to post these data to a FTP site for downloading by neighboring RTOs as required by their own process and schedules. As an alternative, the parties have considered requesting NERC to modify the IDC to allow for selected interrogation by the RTOs. The actual method used to accomplish this data exchange will be determined in future discussions.

Reservations

Beyond the operating horizon, the impacts of existing transmission reservations are also necessary for the calculation of TTC and ATC for future time periods. The actual transmission reservation information will be exchanged among the RTOs for integration into their own TTC/ATC determination process. This information will also be made available via an FTP site. However, since a transmission reservation is a 'right to use' not an obligation to use the transmission system, the certainty of any particular reservation resulting in a corresponding interchange schedule is open to some level of speculation. This is especially true considering that the pro forma tariff allows firm service on a given path to be redirected as non-firm service on any other path. In addition, the ultimate transmission customer may not have, as yet, purchased all transmission reservations on a particular source-to-sink path. Further complicating this dilemma is that the duration or firmness of the 'second half' of the reservation may not be the same as the 'first half'. Therefore, since the portions of a source to sink reservation may not be able to be associated, prior to scheduling, double counting in the ATC determination process is a possibility. Therefore, information exchange regarding transmission reservations is necessary; however, the reservations themselves may not be incorporated into transmission models of the neighboring RTO. Each RTO will develop practices for

modeling reservations, including external reservations, and netting practices for any allowance of counterflows created by reservations in electrically opposite directions. The procedures developed and implemented by each RTO to model intra-RTO reservations, reservations on external RTOs, and reservation netting practices will be shared with all adjoining RTOs.
Each RTO should also create and maintain a list of reservations from their OASIS that should not be considered in ATC calculations. Reasons for these exceptions may include grandfathered agreements that grant access to more transmission than is necessary for the related generation capacity and unmatched intra-RTO partial path reservations. If the RTO does not include it in its own evaluation, it should be excluded in other RTOs' analysis.

Load Data

Peak load data for the period (e.g. daily, weekly and monthly) will continue to be provided via the NERC SDX System. Since, by definition, peak load values may only apply to one hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the next 7-day horizon, it was agreed to either: supply hourly load forecasts OR daily peak load forecasts with a load profile. All load forecasts would be provided on a Control Area basis.

Calculated Firm and Non-firm Available Flowgate Capability (AFC)

The Available Flowgate Capability (AFC) is the applicable rating of the Flowgate less the projected loading across the particular Flowgate less Transmission Reliability Margin and Capacity Benefits Margin. The Firm AFC is calculated with only the appropriate firm transmission service reservations (or interchange schedules) in the model, while the non-firm AFC is determined with both firm and non-firm reservations (or interchange schedules) modeled. Each RTO will accept or reject transmission service requests based upon projected loadings on their own Flowgates as well as the loadings on 'foreign' Flowgates, this data is required to determine if a transmission service reservation (or interchange schedule) will impact Flowgates to an extent greater than the (firm or non-firm) AFC. Therefore, the Firm and Non-firm AFC for all relevant Flowgates will be exchanged among the RTOs. Each RTO will also limit approvals of Transmission Service Requests so as to not exceed the sum of the thermal capabilities of the tie lines that interconnect the RTOs.

Available Flowgate Rating

The Available Flowgate Rating is the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the Flowgate. The Flowgate rating is in units of megawatts. If the Flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions. The RTOs will provide the neighboring RTOs with (seasonal, normal and emergency) ratings as well as the limiting condition (thermal, voltage, or stability). This information will be updated as required by changes on the system, but these ratings are currently fairly static values and do not currently require frequent updating.

Identification of Flowgates

Flowgates that may initiate a TLR event must be considered in the RTO’s TTC and ATC determination process. Foreign Flowgates that have a response factor equal to or greater than the distribution factor cut-off must be included in the evaluating RTO’s model, as practical.

Configuration/facility changes (for EMS model updates)

Transmission configuration changes and generation additions (or retirements) are normally communicated via the NERC MMWG process. The short term TTC/ATC determination processes are (will be) based upon an EMS model of the transmission system. Since frequently comparing the MMWG cases with the RTO’s EMS models would be a significant, if not impractical task, a mechanism must be instituted to ensure that all significant system changes of a neighbor are incorporated in each RTO EMS model. Although this information and a host of very detailed data are included in the MMWG cases, this data exchange mechanism will address the ‘major’ changes that should be included in the EMS based Models in a more timely manner. This type of data change would be similar to the ‘New Facilities’ Listings usually included in Interregional reports; however, explicit modeling information would need to be supplied along with the listing. It is envisioned that this data exchange should occur no less often than prior to each peak load season. In addition, the RTOs agree to exchange EMS models of their transmission systems as mechanisms can be established to facilitate this exchange.

II. Procedures

The three RTOs participating in this seams effort have agreed to ATC coordination procedures designed to minimize the likelihood of over-reserving or over-scheduling of the transmission system. The procedures call for exchanging information that enables each RTO to identify the effects of system conditions in adjoining RTOs on their own Flowgates. These procedures also call for exchanging Flowgate AFCs with adjoining RTOs to recognize limits on foreign Flowgates as well as their own Flowgates as each RTO accepts Transmission Service reservations and/or schedules that transmission service.

These procedures describe the process for exchanging near-term planning information and AFCs. Each RTO will have its own internal procedures for incorporating information provided by the adjoining RTOs in their power flow models and utilizing foreign Flowgate information when granting and scheduling transmission service. How these internal procedures work are not part of the coordination procedures. Each RTO can use different internal procedures and still accomplish acceptable coordination.

The following sections describe the ATC coordination procedures each RTO will follow. The ATC coordination procedure will be integrated by the RTOs into their own internal procedures for creating power flow models for determining AFCs. The ATC coordination procedures can be divided into two distinct activities: 1) calculation and posting of AFCs and 2) granting and scheduling transmission service. Individual descriptions of each activity are detailed below. However, these two activities are inter-dependent. (See figures 1 and 2 below)

Fig. 1 Periodic and Continuous Update of Flowgate AFC

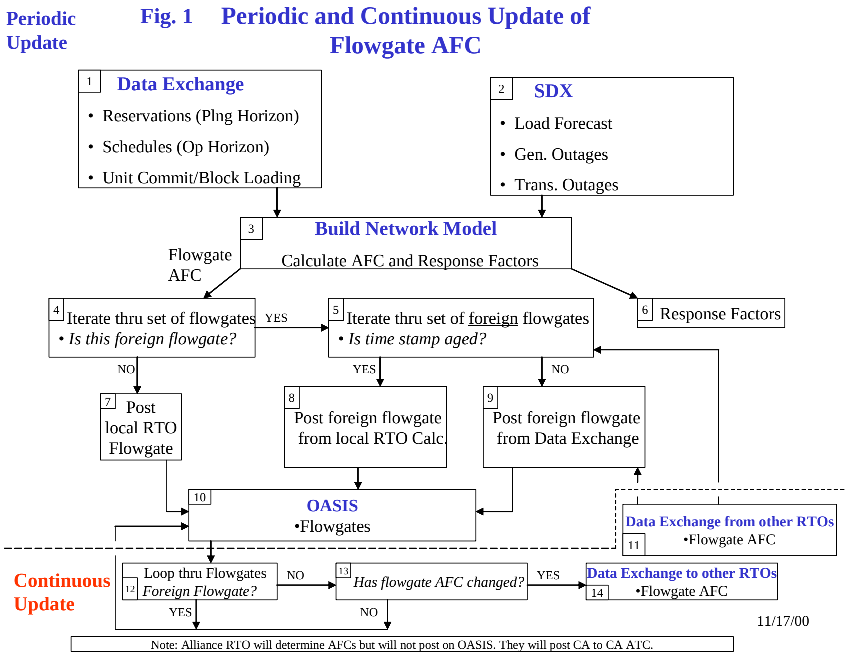
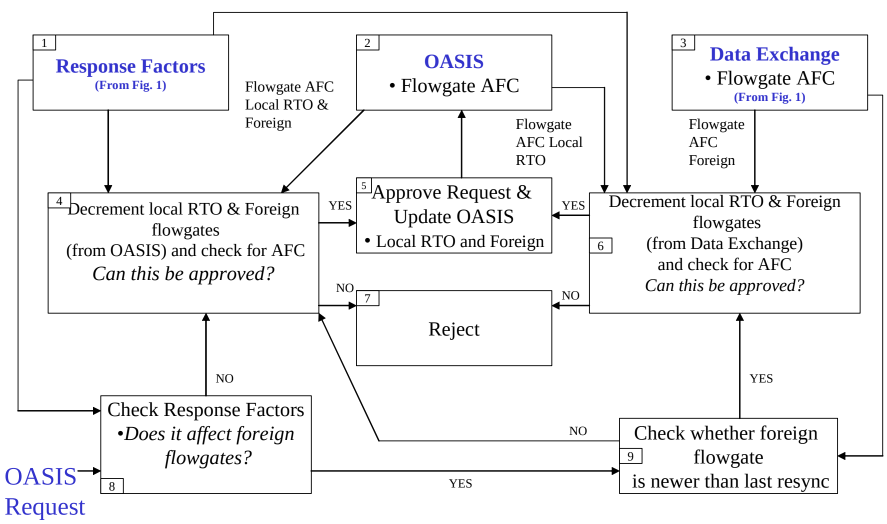


Fig. 2 When Transmission Service Request Is Made



Calculating and Posting ATCs

Coordination of ATCs requires that system conditions in neighboring RTOs will be recognized and included when calculating AFCs. Therefore, each RTO will use AFCs for foreign Flowgates when evaluating transmission service requests. A flow diagram of the process that the RTOs will follow for calculating and posting ATCs is included in Figure1. The flow diagram describes AFC determination. AFC values can be converted to Control Area (CA) to Control Area ATC values by dividing the most limiting Flowgate AFC by its response factor.

The process was developed based on the following assumptions:

- Each RTO will develop its own set of Flowgates and their applicable ratings and margins. Adjoining RTOs will acknowledge foreign Flowgate limitations to the extent the owning RTO operates to its own Flowgate limitations.
- Power flow models will be developed on a periodic basis to calculate AFC using information available via the data exchange from adjoining RTOs.
- AFCs are to be updated (i.e. decrement AFC using response factors and reservations) on a continuous basis but no less frequently than:
  - Once every two (2) hours for hourly and daily AFCs
  - Once a day for monthly AFC
- Each RTO will determine the response factors for local and foreign Flowgates for use by the individual RTO.
- Each RTO will post CA-to-CA ATC and/or Flowgate AFC for both their own Flowgates and adjoining RTO Flowgates. This allows transmission customers to view postings that may impact their ability to obtain transmission service
- Each RTO will compare adjoining RTO Flowgate AFCs they calculate with the AFC exchanged by the RTO responsible for the Flowgate for similar time periods and types of service. Where significant differences are caused by factors other than the recognition of different transmission services sold by each RTO, the RTOs will, either individually or on a joint basis, take steps to improve the AFC calculation process.
- Each RTO will update their own Flowgate AFCs on the data exchange. The data exchange update should be done at the same time the OASIS postings are updated to assure consistency in the data used by others. The participating RTOs will post these data no less often than once per hour or more often if necessary.
- An RTO will use the foreign Flowgate AFCs provided via the data exchange in their respective ATC determination processes. If valid (i.e. 'fresh') foreign AFC values are not available from an RTO, the calculating RTO will default to use the local RTO's current AFC value for the foreign Flowgates.

- The participating RTOs have agreed to monitor their processes and shorten the periodicity if they find overselling of transmission service or underutilization of the transmission system is occurring. (Note: The periodicity that is used to post AFC on the data exchange and the periodicity used by the participating RTOs accessing and utilizing foreign Flowgate information in the ATC determination process is an ATC coordination issue. This time lag represents the amount of time each RTO continues to do business without recognizing recent commitments of other RTOs).
- All participating RTOs shall use the response factor cut-off that the owning/operating RTO uses for their Flowgate in their ATC determination efforts.

The sequence for calculating and posting AFCs is summarized below. Refer to Figures 1 and 2.

1. Each RTO will have its own periodicity for calculating (i.e. full network analysis) and updating AFCs. A RTO may have several periodicities depending on the service being offered (i.e., hourly AFC for the first 7 days may be updated once an hour, daily AFC for days 8 through 31 may be updated once a day and monthly AFC for months 2 through 13 may be updated once a week).
2. Each RTO will utilize data from the data exchange and the SDX as inputs to model development. These power flow models will also reflect system conditions in adjoining RTOs.
3. The power flow models will provide Flowgate base flows used to determine AFC and will be used to calculate response factors for CA-to-CA transactions.
4. Before utilizing calculated AFCs from the power flow models, a check will be made whether it is a foreign Flowgate. If it is a foreign Flowgate, the AFC value from the data exchange will be used unless the time stamp indicates the data exchange supplied data is ‘aged’. If the foreign RTO data is aged then the AFC from the power flow model is used.
5. If it is a local RTO Flowgate, AFC from the power flow model is used for posting on OASIS and sent to the data exchange for use by other RTOs.
6. A continuous function is shown on Figure 1 that checks for changes in AFC on all posted Flowgates. If the Flowgate is a foreign Flowgate, no action is taken. If the Flowgate is a local Flowgate and has changed, the changed AFC is posted on the data exchange. This is intended to capture the effects of periodic calculations of AFC and the effects of changes to AFC when transmission service is granted.

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Craig Glazer, Vice President, Government Policy, PJM Interconnection, L.L.C.

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Granting and Scheduling Transmission Service

Coordination of ATC values is involved in the granting of transmission service in that service should not be sold if it results in projected loading on a Flowgate that exceeds the Flowgate operating security limits. A general flow diagram of the process that the RTOs will follow when granting transmission service is in Figure 2. The process was developed based on the following assumptions:

- It is assumed a request for transmission service will be refused if AFC is not available. A request will not be refused if there are alternatives that can be used to create AFC (bumping lower priority service, offering higher price for same priority service, customer initiated redispatch, etc.).
- The RTOs are updating Flowgate AFCs as transmission service requests are accepted.
- A check will be made of all foreign Flowgates that are impacted by the pending transmission service request to ensure that they have been updated in the data exchange.
- Response factors for all Flowgates are calculated by each RTO.
- This process assumes that other mechanisms are in place to ensure that partial path issues that may result in inadvertent double counting the same transmission service is addressed. These are coordination details that need to be addressed.
- This process addresses only limitations that can be quantified or equated to thermal limits. Other reviews such as voltage, stability and network analysis may be required before granting the service.

The sequence for granting and scheduling transmission service is summarized below.

1. When a request is received, the set of response factors for the specific source and sink will be checked for impacts on foreign Flowgates. If there are no foreign Flowgates with impacts, the request will be processed without further consideration of foreign impacts.
2. If a transmission service request impacts a foreign Flowgate by equal to or greater than the response factor cut-off, the process is to check whether there has been a recent update of the foreign AFC via the data exchange. If the data exchange has been updated the foreign AFC will be decremented accordingly.
3. If the data exchange has not been updated, the process will decrement the RTOs own calculated AFC of the foreign Flowgate.
4. This process is repeated for all impacted Flowgates. If all Flowgate AFCs remain positive after decrementing, the request is approved and its impact will be included in the next OASIS update.

5. If the request results in a projected Flowgate loading exceeding its operating limits, then the request should be denied and the OASIS postings remain unchanged.
6. As described in Calculating and Posting ATCs section, once the evaluating RTO OASIS is updated with AFC changes, these changes will be posted on the data exchange for the RTO's own Flowgates. The newly approved reservation will be available to adjoining RTOs as they calculate their own Flowgate AFCs.

Use Schedules Not Reservations for Horizons where Schedules Exist

Schedules should replace reservations in the power flow model being used to determine AFCs. This may result in additional transmission capacity being available if the schedule is less than the reservation or if the schedule is creating a counter-flow to a constraint.

III. Other Issues

As part of the ATC coordination, there are certain rights and responsibilities that are agreed to be reserved for the owning RTO. These rights include the sole determination of the AFC value to be honored by participating RTO's. The TRM and CBM values for each Flowgate will be determined by the owning RTO.

The modeling of transmission reservations for determination of AFC within each participating RTO remains a concern. Problems with partial path reservations, inadequate tag information, and accuracy in predicting actual energy flow are issues that every RTO must address. The balance between over or under utilization of the transmission system resides with the decision on which transactions to model in determining remaining AFC. As described previously, each participating RTO will share data on transactions and Flowgate impacts of modeled transactions. It will be each RTOs responsibility to determine which reservations and schedules are to be incorporated in their model to determine AFC values for the period in question. Each RTO will commit to standardizing this process as much as practical within RTO operating guidelines.

The congestion management plan that each RTO implements may affect the coordination process for determining inter-regional transfer capability. A reexamination of the treatment of foreign Flowgates may be necessary depending on the congestion management plans.

PJM/MISO/SPP
Flowgate Information Exchange Process

The following types of data will be exchanged among the RTOs for the purpose of setting up more accurate network modeling cases, determining the impact of other's transmission service sales on internal Flowgates, and for the purpose of honoring external Flowgates when selling transmission service.

Reservation Information – Transmission Service sold will be used by each RTO in determining the impact on internal Flowgates of service sold by the other RTOs.

Scheduling Information – Used for the same purpose as reservation information, except in the scheduling time frame.

Flowgate Ratings and Available Capability – When determining whether to accept a new transmission reservation, each RTO will honor the AFC values calculated by the RTO that "owns" the Flowgate.

System Information such as loads, equipment outages, generator availability and generation dispatch order.

Transmission Reservations

1. Transmission reservations that are in confirmed, accepted, or study mode will be exchanged via a file that contains all Transmission Reservations made on the RTO system for a minimum of 13 months and beyond this as necessary.

2. Transmission reservation data will be exchanged via two types of files, a base file and an update file.

3. The base file will be updated once a day and will contain all reservations on the RTO system for a minimum of 13 months and beyond this as necessary. This file should be generated and sent by 2330 each day.

4. Within each day, a file will be generated every hour which contains the new reservations in either confirmed, accepted, or study status within the last hour. The time that this file will be sent will be determined at a later date.

5. All files generated will have as the first record, the date and time the data was last updated. All dates and times will be in GMT or as mutually agreed.

6. Each RTO will use the reservations contained in these files for calculating base flow information.

7. The data to be included in the reservation file is as follows: OASIS number, Transmission Provider, Start Time, Stop Time, MW sold (All segments), Priority, Source/Sink. All times shall be in GMT or as mutually agreed.

Scheduling Information

1. Schedules will be exchanged via a file that contains all schedules for the current and next day.

2. The data to be included in the schedule file is as follows: Tag #, OASIS number(s), Transmission Provider, Start Time, Stop Time, MW schedule, Source/Sink. All times shall be in GMT or as mutually agreed.

3. Schedule Files will be updated as new schedules come in.

Flowgate Ratings and Available Capability

1. Total Flowgate Capability (TFC) and Available Flowgate Capability (AFC) information will be exchanged via a file that contains this data for a RTOs Flowgates for a minimum of 13 months and beyond this as necessary.

2. TFC and AFC data will be exchanged via two types of files, a base file and an update file.

3. The base file will be updated once a day and will contain all TFCs and AFCs on the RTO system for a minimum of 13 months and beyond this as necessary. This file should be generated and sent by 2330 each day.

4. The update file will be continuously updated during the day as new transmission reservations are accepted, confirmed, or placed in study mode. This will be done at the same time as the OASIS posting is made.

5. Once Flowgate values are received, decisions to sell service will be made using internally calculated response factors on the external Flowgates.

6. This file will be considered old when it is not updated as follows: 2 hours for either hourly or daily AFCs, 1 day for monthly AFCs

System Information

1. The NERC SDX System is the vehicle to exchange system information.

2. SDX data will be updated at least daily for all time horizons through month 13.

3. Load Data will supplied as follows: Daily peak forecasts (for 30 days) and monthly peak load forecasts for months 2 through 13. For the next 7 day horizon, hourly load forecasts OR daily peak load forecasts with a load profile will be provided. All of the above load forecasts would be on a Control Areas basis.

4. Transmission outages (including critical lower capability facilities), forced outages and return dates, and generation availability will be provided.

5. Generation dispatch order will be exchanged to determine appropriate generation dispatch for various scenarios.

PJM/MISO/SPP
AFC Rating and AFC File Format

Each Filename would have the name: RTONAME_Flowgateinfo

The format of the file is as follows:

1. The first record of the file should contain the date and time the data was calculated in the following format: mm/dd/yyyy xx:xx:xx

2. Each Record of the file following the first record should indicate Flowgate ratings and values as follows:

   - The first letter of each record indicate the time of the Flowgate record as follows:
   - Y = Year, M = Month, D = Day, and H = Hour

   - The second letter of each record indicates whether the record is a firm or a non-firm record type with F meaning Firm and N meaning Non-Firm

   - Following these two record type indications would be entries indicating the timeframe of the values given in the record, the Flowgate name, the Total Flowgate Capacity (TFC) for each period (with TRM and CBM already excluded), and Available Flowgate Capacity (AFC) for each period.

An example for each time frame is as follows:

YF, yyyy-yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,, AFCX
MF, mm/yyyy-mm/yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
MN, mm/yyyy-mm/yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
DF, mm/dd/yyyy-mm/dd/yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
DN, mm/dd/yyyy-mm/dd/yyyy, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX
HN, mm/dd/yyyy/hh-mm/dd/yyyy/hh, Flowgate_ID, TFC1, TFC2,,,,TFCX, AFC1, AFC2,,,,AFCX

Where:

All Dates and Times are in CST
yyyy = year
mm = month (1=Jan, … 12=December)
dd = Day of the month
hh = Hour of the day (Hour Ending 1 through Hour Ending 24)

Appendix K – Audit Procedures

MISO and PJM Market Flow, NNL, and Economic Dispatch Audit Procedure

MISO and PJM each under go rigorous internal and external audits of their processes (including SAS 70 Type II audits) to ensure they document processes, have proper control checks on their processes, and strictly follow the processes. Employees are required to follow the processes as a condition of employment at each organization. Further, MISO and PJM each are independent organizations and adhere to FERC's requirements for independence.

MISO and PJM will be calculating Market Flow, prioritizing those flows, and providing them to the IDC. The NERC IDC will calculate curtailment and redispatch requirements based, in part, on the MISO and PJM provided inputs. To provide even greater confidence that MISO and PJM are following the established processes for calculating these IDC inputs, MISO and PJM each volunteer to undergo this NERC administered audit process. The audit process will be pattern after the previous NERC Tag Audit. The audit process is as follows:

1. Once per month and after-the-fact, NERC will choose a time and Coordinated Flowgate to audit. The time chosen will typically be during an hour when TLR activity was occurring on one of the Coordinated Flowgates where MISO and/or PJM provide market flow values.

2. PJM and MISO will provide a record of loads, zonal generation, calculation, distribution factors, market flow calculations for the audit time, and resulting values provided to the IDC. Data confidentiality requirements of MISO, PJM, NERC, and FERC will be strictly followed.

3. NERC Staff will compare audit report results with values that were actually provided to the IDC for audited Flowgate and report any discrepancies to the NERC Operating Reliability Subcommittee (ORS).

4. The ORS will monitor this audit process and make recommendations for improvements as necessary.

5. Once three successful monthly audits are completed, the audits will be conducted quarterly.

Appendix L - Determination of Marginal Zone Participation Factors for PJM

In order for the IDC to properly account for tagged transactions, an RTO will need to send data describing the locations of the marginal generators that are either supplying generation to exports or are having energy replaced by imports.

In general, the RTO will be required to define a set of zones that can each be easily aggregated into a common distribution factor that is representative of the zone. This information must be shared and coordinated with the interchange distribution calculator. Following this step, the RTO must then send to the IDC participation factors for those zones (percentages that indicate on a real-time basis how those zones are providing or would provide marginal megawatts). Two sets of data are required:

- An IMPORT set, which indicates the next marginal units to supply replacement energy should the import transactions be curtailed, and
- An EXPORT set, which indicates the last marginal units used to supply the energy exported to other areas.

Marginal Zone Definition

Marginal Zones will be determined through collaboration of the RTO with the NERC Distribution Factor Working Group. As stated above, Marginal Zones should be comprised of generators that have electrically similar characteristics from a distribution factor point-of-view.

Participation Factor Calculation

Raw Marginal Zone Participation Factors are determined relatively simply. The RTO will examine the constraints and pricing information for the entire market footprint and determine the percentages of generation output in each zone that represents next marginal megawatts and last marginal megawatts. These will establish, for imports and exports, a set of participation factors that, when summed, will equal 100%.

If an RTO is comprised of multiple Control Areas, the RTO create a set of marginal zones for each Control Area and perform a Control Area Weighting. The marginal zones for a single Control Area will include all marginal zones for the entire market footprint. For very Control Area, the following weighting factors will be assigned:

- If the CA is Importing on an Inter-CA Schedule and Importing via Interchange:
  - Their factor for imports is equal to their Interchange value (assume all imports are to serve load), but no less than 1
  - Their factor for exports is 1 (they are not exporting)
- If the CA is Exporting on an Inter-CA Schedule and Exporting via Interchange:
  - Their factor for imports is 1 (they are not importing)
  - Their factor for exports is equal to their Interchange value (assume they are serving all exports), but no less than 1

If all Control Area factors are equal, then it is assumed that each zone is importing/exporting and equal share. Otherwise, all factors should be used to determine a Control Area participation factor that can be used to scale the Marginal Zone participation factors.

Next, the RTO should apply a Inter-CA Schedule Transfer Potential weighting. As an Inter-CA schedule approaches its limit (either contractual or reliability-imposed), its ability to move marginal generation across the transfer becomes reduced. Each CA to CA transfer within the market, therefore, must be appropriately reduced as well. The reduction function is as follows:

$$TransferPotential = \frac{\sqrt{Limit - Flow}}{\sqrt{Limit}}$$

This provides a smoothed transition from unconstrained to constrained potential. For flows in the reverse direction, transfer potential is always assumed to be 100%.

These transfer potentials are applied to each set of marginal zone data as appropriate, resulting in a set of marginal zones that reflect the ability of the markets marginal zones to address Control Area balancing.

Appendix M - Flowgate Determination Process

This section is has been added to clarify:

- How initial Flowgates are identified (Figure M-1, Table M-1)
    - Process for Flowgates in the Coordinated Flowgate list
    - Process for Flowgates in the Reciprocal Coordinated Flowgate list
    - Process for Flowgates in the AFC List
- How Flowgates will be added (Figure M-2, Table M-2)
- How often Flowgates are changed (Figure M-2, Table M-2)

Figure M-1
Determine AFC Flowgates,
Coordinated Flowgates, and Reciprocal
Coordinated Flowgates

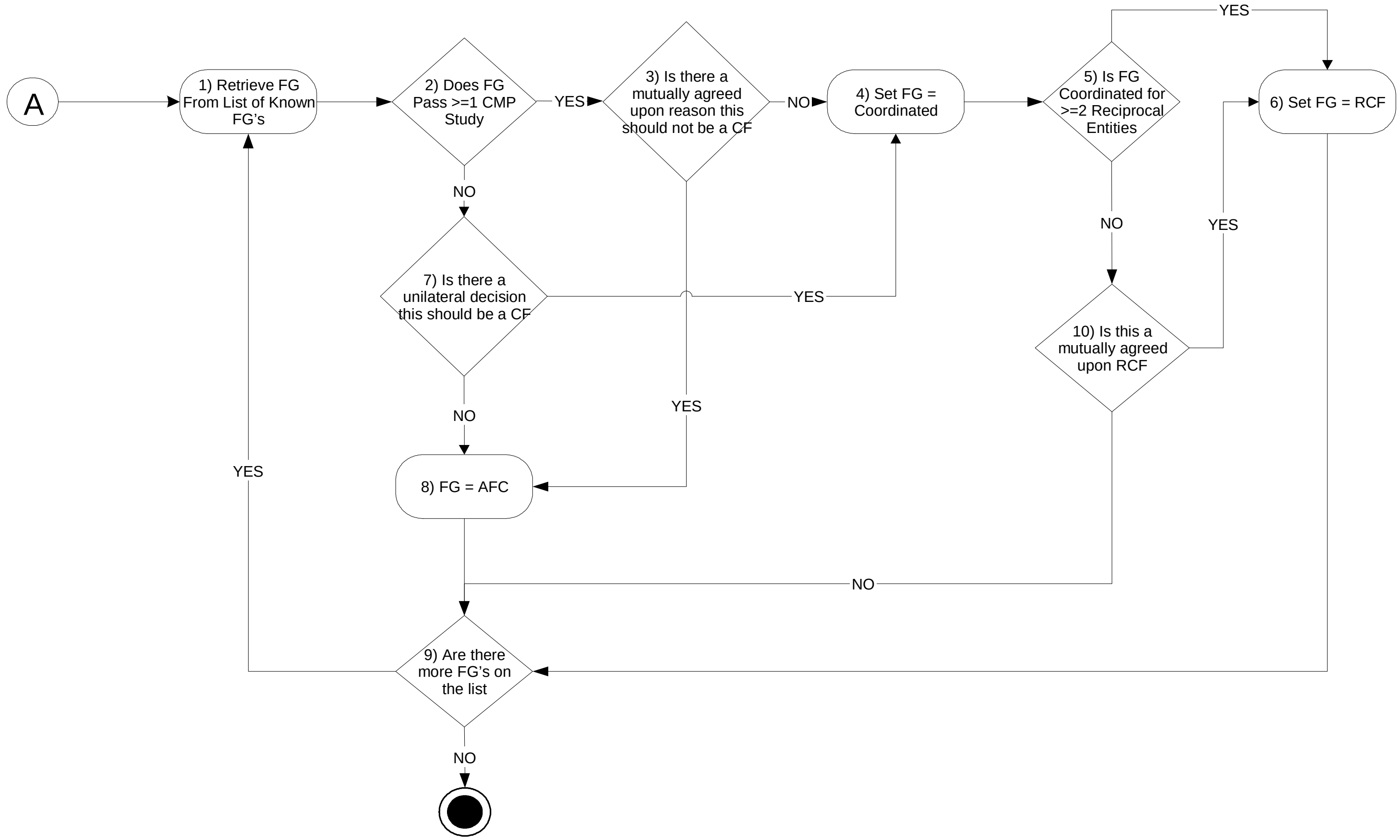

Table M-1				
Step	**Activity**	**Requirements**	**Detailed Description**	**Additional Documentation**
1	Retrieve FG From List Of Known FG's	Retrieve FG from AFC list of FGs, NERC Book of FGs, and any other list of FGs.	• Retrieve the FG from the list of FGs. If a party wants us to consider a temporary FG it would go through the same process.	
2	Determine if FG passes >= 1 CMP Study	The decision determines if the FG passes at least one of the four CMP studies	• If the FG passes any of the studies, determine if there is mutually agreed upon reason why this should not be a coordinated FG. • If the FG does not pass any of the studies, it will be determined if there is a unilaterally decided reason for inclusion as a CF	CM Process -Section 3
3	Is There a Mutually Agreed Upon Reason This Should Not Be A Coordinated FG	Determine if there is a mutually agreed reason, despite passing one of the four tests, why this FG should not be considered Coordinated.	• If there is no mutually agreed reason why this FG should not be considered coordinated, set the FG equal to coordinated. • If there is a mutually agreed reason why this FG should not be considered coordinated, record the reason and set it equal to AFC FG.	

5	Is FG Coordinated for >= 2 Reciprocal Entities	Determine whether the FG is coordinated for two or more reciprocal entities	• If the FG is coordinated for two or more reciprocal entities, it will be added to the CMP process as a reciprocal coordinated FG. • If it is not coordinated for two or more reciprocal entities, determine if it is a mutually agreed upon RCF.	CM Process -Section 6
6	Set FG = RCF	Set the flowgate equal to a reciprocal coordinated flowgate.	• Set the flowgate equal to a reciprocal coordinated flowgate.	
7	Is There a Unilateral Decision This Should Be A Coordinated FG	This decision determines if an entity wants to make this a Coordinated FG for a reason other than the four tests.	• If an entity decides to make this a coordinated FG, set FG = Coordinated. • Otherwise , set the FG = AFC.	
8	Set FG = AFC	The FG would remain an AFC FG.	• The FG would remain an AFC FG.	
9	Are there more FGs on the list?	Determine if there are any more FGs on the list that need to go through the CMP determination process.	• If there are no more FGs that need to go through the determination process, the process ends. • If there are more FGs that need to go through the determination process, retrieve the next one.	
10	Is This a Mutually Agreed Upon RCF	Determine if there is a mutually agreed reason this should be considered	• If there is no mutually agreed reason this should be considered a RCF, leave it as coordinated and check for more	

		a reciprocal coordinated flowgate.	FGs. • If there is a mutually agreed reason this should be considered a RCF, mark it as such.	

Figure M-2
Flowgate Review and Customer Flowgate Request

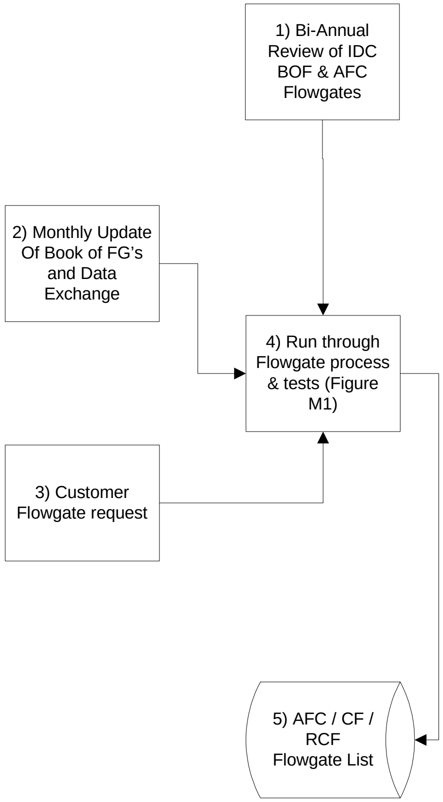

Table M-2				
Steps	**Activity**	**Requirements**	**Detailed Description**	**Additional Documentation**
1	Bi-Annual Review of the BOFs and AFC FGs	Retrieve the FG from the list of FGs for the entity running the process.	• Flowgate review should be done consistent with the IDC summer/winter base case changes, which would occur twice per year instead of Quarterly. Each base case update done at NERC for the IDC will need a certain amount of review just to make sure that current flowgates will continue to function with the new model. The FGs will be run through the process summarized in figure M-1.	
2	Monthly update of the Book of Flowgates and Data Exchange	Take monthly updates from book of flowgates, monthly full files and monthly incremental files and run them through the flowgate process and tests.	• Monthly the parties will perform full flowgate updates and synchronization. In addition the NERC Book of Flowgates is updated once a month. We will run these changes through the process summarized in figure M-1.	
3	Customer FG Requests	Any customer FG requests will also be subject to the tests and process above.	• Any customer FG requests will be run through the process summarized in figure M-1.	

4	Run Through FG Process and Tests	Run through FG Determination Process, Figure M-1	• Any FGs being reviewed or added will be run through the process summarized in figure M-1.	
5	AFC/CF/RCF List	Any FG additions or modifications would need to be committed to the repository of FGs and their qualifications	• Any FG additions or modifications would need to be committed to the repository of FGs, along with their qualifications	

Attachment 3

Interregional Coordination Process

Version 1.8

Midwest ISO & PJM Market–to–Market Interregional Coordination Process Table of Contents

Preface

The purpose of this Interregional Coordination Process ("ICP") is to provide a description of the proposed Market-to-Market coordination process that will be implemented concurrently with the implementation of side-by-side LMP-based energy markets in the PJM and Midwest ISO regions. Specifically, this ICP presents an overview of the market-to-market coordination process, an explanation of the coordination for market pricing at the regional boundaries, a description of the Real-Time and Day-Ahead coordination methodologies, an example to illustrate the Real-Time coordination, and the associated settlements processes.

1 Overview of the Market-to-Market Coordination Process

The fundamental philosophy of the PJM/Midwest ISO interregional transmission congestion coordination process is to set up procedures to allow any transmission constraints that are significantly impacted by generation dispatch changes in both markets to be jointly managed in the security-constrained economic dispatch models of both RTOs. This joint management of transmission constraints near the market borders will provide the more efficient and lower cost transmission congestion management solution, while providing coordinated pricing at the market boundaries.

The market-to-market coordination process builds upon the PJM/MISO market-to-non-market coordination process, as described in the "Congestion Management Process" document ("CMP") filed as part of the Midwest ISO – PJM Joint Operating Agreement. That CMP describes the interregional coordination process between a market region that uses an LMP-based congestion management regime and a non-market region that uses a TLR-based congestion management regime (i.e., a market to non-market interface). As described in the CMP, the set of transmission flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market is identified as the set of Reciprocal Coordinated Flowgates (RCFs). These RCFs are then monitored to measure the impact of market flows and loop flows from adjacent regions. The CMP describes how the market flow impacts will be managed on an interregional basis within the existing NERC IDC to enhance the effectiveness of the NERC interregional congestion management process. The CMP also describes a process for calculating flow entitlement for network and firm transmission utilization in one region on the RCFs in an adjacent region.

The market-to-market coordination process builds on the work already completed, as described above, by adapting the coordination, as appropriate, to the conditions that will prevail after both the PJM and Midwest ISO markets are implemented in the Midwest. In addition, there is a continuing need to define the flow entitlement for network and firm transmission utilization in one region on the RCFs in an adjacent region.

- **Real-Time Energy Market Coordination** -- The market-to-market coordination focuses primarily on Real-Time market coordination to manage transmission limitations that occur on the RCFs in a more cost effective manner. This Real-Time coordination will result in a more efficient economic dispatch solution across both markets to manage the Real-Time transmission constraints that impact both markets, focusing on the actual flows in Real-Time to manage constraints. Under this approach, the flow entitlements on the RCFs do not impact the physical dispatch; the flow entitlements are used in market settlements to ensure appropriate compensation based on comparison of the actual market flows to the flow entitlements.

- **Day-Ahead Energy Market Coordination** -- The Day-Ahead market coordination focuses primarily on ensuring that the Day-Ahead scheduled flows on all RCFs are limited to no more than the Firm Flow entitlements for each RTO. Under certain conditions, an RTO may request that the Day-Ahead flow limit be raised above its Firm Flow entitlement but this is expected to happen only by exception under abnormal conditions.

- **FTR Allocation & Auction Coordination** -- The Financial Transmission Rights (FTRs) allocation and auction processes in both RTOs will model the Firm Flow entitlements on all RCFs.

As stated previously, only a subset of all transmission constraints that exist in either market will require coordinated congestion management. This subset of transmission constraints will be identified as RCFs in a manner similar to the method used in the CMP described above. The list of RCFs will be limited to only those for which at least one generator in the adjacent market has a significant Generation-to-Load Distribution Factor (GLDF), sometimes called "shift factor," with respect to serving load in that adjacent market. NERC rules currently establish that a significant shift factor is five percent or greater). If NERC adopts a lower threshold than 5%, the new threshold will be used to determine whether the generator has a significant GLDF for the purpose of this market-to-market ICP. As a further clarification, PJM and MISO will only be performing market-to-market coordination on RCFs that are under the operational control of PJM, Midwest ISO, or another third party Reciprocal Entity. PJM and MISO will not be performing market-to-market coordination on RCFs that are owned and controlled by third party entities or on flowgates that are only considered to be coordinated flowgates.

2 Interface Bus Price Coordination

Proxy bus prices are calculated by each RTO to reflect the economic value of imports or exports from the neighboring RTO. For example, the proxy bus price for RTO A as calculated by RTO B is driven by the economic dispatch of RTO B, therefore this proxy price will reflect the system marginal price in RTO B, plus any congestion cost adjustment and marginal loss cost adjustment based on the proxy bus location. The coordinated operation of RCFs will tend to force the pricing at the RTO borders to be consistent with the energy prices at generators and load busses near the RTO border points.

In order for the market-to-market coordination to function properly, the proxy bus models for PJM and MISO must be coordinated to the same level of granularity. Therefore, the proxy bus modeling approaches must be similar such that the prices are consistent. This does not necessarily mean the proxy bus prices will be the same, particularly in the initial implementation of Market-to-Market coordination. What is important at the outset is that the proxy buses reflect consistent pricing between the RTOs given the constraints for which each RTO is operating. Consistency means that the proxy bus price one RTO calculates for the other RTO reflects the nature of the congestion on both RTO's systems, such that imports and exports to and from one RTO to the other are provided the correct incentives given their effect on the current binding constraints. A description of the current proxy bus modeling process used by PJM and Midwest ISO is posted on each RTO's OASIS.

As the Market-to-Market coordination process continues to evolve, it may be possible to get to the point that each RTO's proxy bus for the other is defined on the RTO border, and the proxy bus prices are actually the same or consistently close. This will require coordination beyond merely operating for constraints on each other's systems, to include tightly coordinating the economic dispatches themselves, in an iterative process as described in Section 7.

3 Real-Time Energy Market Coordination

When any of the RCFs become binding in the Monitoring RTOs Real-Time security constrained economic dispatch, the Monitoring RTO will notify the Non-Monitoring RTO, requesting that the Non-Monitoring RTO maintain its current market flow. The Monitoring and Non-Monitoring RTOs will provide the economic value of the constraint (i.e., the shadow price) as calculated by their respective dispatch models. Using this information, the security-constrained economic dispatch of the Non-Monitoring RTO will include the transmission constraint; the Monitoring RTO will evaluate the shadow prices within each RTO and request that the Non-Monitoring RTO reduce its market flow if it can do so more efficiently than the Monitoring RTO (i.e., the Non-Monitoring RTO has a lower shadow price than the Monitoring RTO).

An iterative coordination process will be supported by automated data exchanges in order to ensure the process is manageable in a Real-Time environment. The process of evaluating the shadow prices between the RTOs will continue until the shadow prices are sufficiently close that an efficient redispatch solution is achieved. The continual interactive process over the next several dispatch cycles will allow the transmission congestion to be managed in a coordinated, cost-effective manner by the RTOs. A more detailed description of this iterative procedure will be discussed in Section 3.1.

This coordinated dispatch protocol will be performed any time that any RCF becomes binding. This approach will produce the level of coordination that will be required to ensure efficient congestion management across the market seams. This approach also will provide a much higher level of interregional congestion management coordination than that which currently exists between any existing adjacent markets.

3.1 Real-Time Energy Market Coordination Procedures

The following procedure will apply for managing RCFs in the real-time energy market:

1. The RTOs will exchange topology information to ensure that their respective market software is consistent.
2. When any of the RCFs under a Monitoring RTOs control is identified as a transmission constraint violation, the Monitoring RTO will enter the RCF into its security-constrained dispatch software, setting the flow limit equal to the appropriate facility rating.
3. The Monitoring RTO will then notify the Non-Monitoring RTO of the transmission constraint violation and will identify the appropriate RCF that requires mitigation.
4. The Non-Monitoring RTO will enter the RCF into its security-constrained dispatch software, setting the flow limit equal to its current market flow on the RCF.
   (a) This means the Non-Monitoring RTO will attempt to manage the flow on the RCF at its current Market Flow amount or less, such that it will not contribute any additional flow on the limited RCF during this time period.

5. When the RCF first becomes a binding transmission constraint in the Monitoring RTOs Real-Time security-constrained economic dispatch, the Monitoring RTO will transmit the following information to the Non-Monitoring RTO:

   - Constraint Shadow Price ($/MW) - output of the RTOs Real-Time market software.
   - Current Market Flow contribution by the Monitoring RTO on RCF (MW) - output of the Real-Time market software.
   - Amount of MWs requested to be reduced from the current market flow of the Non-Monitoring RTO. This number will change throughout the iterative process to efficiently resolve constraints.

6. The Non-Monitoring RTO will then transmit the following information to the Monitoring RTO:

   - Constraint Shadow Price ($/MW) - Output of the RTOs Real-Time market software. (If the RCF does not result in a binding constraint in the Non-Monitoring RTO's security-constrained economic dispatch, then the shadow price is zero and the Flow Relief is zero for the Non-Monitoring RTO.)
   - Current market flow contribution by the Non-Monitoring RTO on RCF (MW) - Output of the RTOs Real-Time market software.

7. The Monitoring RTO will then perform an analysis to compare the constraint shadow price information received from the Non-Monitoring RTO to its own constraint control information to determine the most economical way to manage the transmission constraint.

8. If required, the Monitoring RTO may request the Non-Monitoring RTO to perform a study to determine additional constraint shadow price information for a requested additional amount of Flow Relief from the Non-Monitoring RTO economic dispatch.

9. Over the next several dispatch cycles the Monitoring RTO may request the Non-Monitoring RTO to adjust its flow limit up or down. The Monitoring RTO will make corresponding changes to its own dispatch with the intent to equalize the constraint shadow prices in the two RTOs. Though the constraint shadow prices will seldom, if ever, be exactly equal, they should be comparable within a reasonable tolerance.

10. Throughout the period that the transmission constraint violation exists, the RTOs will continue to share the flow and constraint shadow price information that is described above. The purpose of these data exchanges will be to maintain the shadow price coordination over time and to retain the pertinent data for Market Settlements.

11. Every 15 to 30 minutes as necessary, the Monitoring RTO will review the constraint shadow price comparison, make required adjustments, and communicate any such adjustments to the Non-Monitoring RTO. This process will continue until the Monitoring RTO determines that the cost of further adjustments to the dispatch of the Non-Monitoring RTO would exceed the cost of relieving the transmission constraint by adjusting the Monitoring RTO's own dispatch.

12. The start and stop times for such Constrained Operation events involving RCFs will be logged for Market Settlements purposes.

3.2 Real-Time Energy Market Settlements

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

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

Payment = (Real-Time Market Flow MW[1] – (Firm Flow Entitlement MW[2] + Approved MW[3])) * Transmission Constraint Shadow Price in Monitoring RTOs Dispatch Solution

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

Payment = ((Firm Flow Entitlement MW[2] + Approved MW[3]) – Real-Time Market FlowMW[1]) * 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).

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1 This value represents the Non-Monitoring RTO's Real Time Market Flow.
2 This value represents the Non-Monitoring RTO's Firm Flow Entitlement.
3 This value represents the Approved MW that resulted from the Day Ahead Coordination.

Issued by: James P. Torgerson, President and CEO, Midwest ISO Effective: April 1, 2005
Craig Glazer, Vice President, Government Policy, PJM Interconnection, L.L.C.

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4 Day-Ahead Energy Market Coordination

The Day-Ahead energy market coordination focuses primarily on ensuring that the Day-Ahead scheduled flows on all RCFs are limited to no more than the Firm Flow entitlements for each RTO. When system conditions can accommodate the change, either RTO may request that the Day-Ahead flow limit be raised above its Firm Flow entitlement. Normally, this protocol will be utilized infrequently and only when the need for additional congestion relief assistance is predictable on a Day-Ahead basis.

The Day-Ahead energy market redispatch protocol may be implemented in the Day-Ahead energy market upon the request of either RTO if the adjacent RTO verifies that such Day-Ahead redispatch is feasible.

An example of the Day-Ahead energy market protocol is as follows:

1. The Requesting RTO specifies the amount of scheduled flow reduction that it is requesting on a specific RCF and communicates the request to the Responding RTO

2. The Responding RTO will then lower the MW limit that it utilizes in its Day-Ahead market on the specified RCF by the specified amount. This means that instead of modeling the RCF constraint at flow entitlement amount, the Responding RTO will model the constraint as the flow entitlement less the requested MW reduction. Therefore, the Responding RTO will schedule less flow on the specified RCF in order to provide Day-Ahead congestion relief for the Requesting RTO. The Requesting RTO may then use the additional MW capability in its own Day-Ahead market.

4.1 Day-Ahead Energy Market Coordination Procedures

The following procedure will apply to the modeling of RCFs in the Day-Ahead energy markets, unless either the Monitoring RTO or the Non-Monitoring RTO requests specific exceptions.

- Each RTO will model all RCFs, for which it is the Reliability Coordinator, in its Day-Ahead market and Day-Ahead reliability analyses, with the limit set equal to the applicable facility limit less the Firm Flow entitlement of the Non-Monitoring RTO.

- Each RTO will model all RCFs, for which it is NOT the Reliability Coordinator, in its Day-Ahead Market and Day-Ahead reliability analysis with the limit set equal to its Firm Flow entitlement for that RCF.

- The Monitoring RTO will include an appropriate loop flow model in its Day-Ahead process. However, this loop flow model will not account for loop flows contributed by deliveries associated with the Non-Monitoring RTO market since these flows are accounted for by the Firm Flow entitlement.

An RCF limit exception is a request to alter the RCF limits, as described above, that will be modeled in the Day-Ahead markets and/or the Day-Ahead reliability analysis. The following procedure will apply for designating RCF limit exceptions:

1. Prior to 0700 EST on the day before the Operating Day, if the Requesting RTO identifies a need to utilize more of an RCF than it is entitled, it may request the Responding RTO to lower its Day-Ahead Market limit below its Firm Flow entitlement by a specified amount for a specified range of hours.

2. If the Responding RTO agrees to provide the limit reduction, it will communicate the approved amount to the Requesting RTO by 0800 EST.

3. The Requesting RTO may increase its limit on the RCF by the specified amount for the specified range of hours.

4.2 Day-Ahead Energy Market Settlements

The market settlements for Day-Ahead congestion relief will be performed in a similar manner to the Real-Time energy market settlements of the coordinated congestion management protocol. The Day-Ahead payment for the RTO that is requesting congestion relief will be calculated as follows:

Requesting RTO Payment to Responding RTO = Approved Day-Ahead Adjustment for RCF * Responding RTOs RCF constraint shadow price.

This payment will be calculated based on the hourly Day-Ahead Market results. If such congestion relief is requested and performed on a Day-Ahead basis, then the Real-Time flow entitlement for the affected hours in the corresponding Real-Time market will be adjusted accordingly.

5 Financial Transmission Rights Allocation/Auction Coordination

The allocation of FTR products in each marketplace must recognize the flowgate entitlement that exists in adjacent markets. The FTR allocation (or Auction) model will contain the same level of detail for adjacent regions as the Day-Ahead market model and the Real-Time market model. Each RTO will allocate (or Auction) FTRs to Network and Firm Transmission customers subject to a simultaneous feasibility test that determines the amount of transmission capability that exists to support the FTRs.

The simultaneous feasibility analysis for each RTO will model that RTO’s flow entitlement on the transmission flowgates in the adjacent region as the market flow limit that must be respected in the FTR allocation and auction processes. The transmission flowgates in each RTO will be modeled in the simultaneous feasibility test at a capability value equal to the flowgate rating minus the flow entitlement that exists for flows from the adjacent market. In this way, the FTR allocation across both RTOs will recognize the reciprocal transmission utilization that exists for Network and Firm transmission customers in both markets.

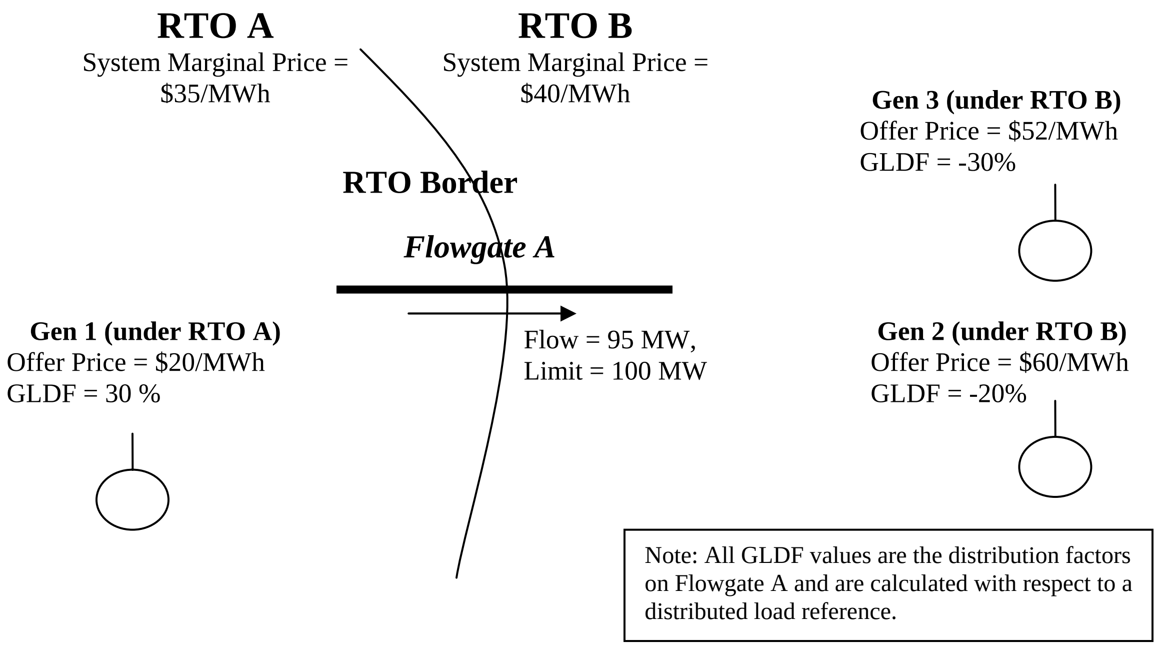
6 Coordination Example

The following example illustrates the Real-Time coordination of an RCF, specifically describing the following five stages:

- Stage 1: Initial Conditions & Energy Prices at Border
- Stage 2: Transmission Constraint Initialization & Energy Prices at Border
- Stage 3: First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Monitoring RTO) & Energy Prices at Border
- Stage 4: First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Non-Monitoring RTO) & Energy Prices at Border
- Stage 5: Ongoing Coordinated Dispatch Cycles

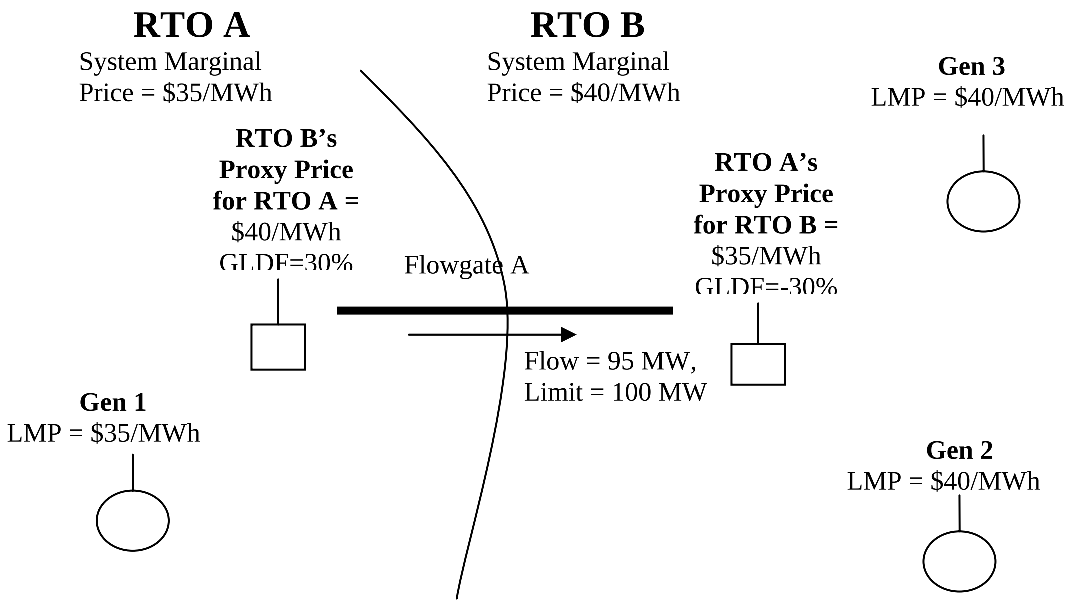
Stage 1 – Initial Conditions

- Marginal Losses are not utilized in this example for ease of understanding
- RTO A is the Non-Monitoring RTO, its system marginal price is $35/MWh
- RTO B is the Monitoring RTO, its system marginal price is $40/MWh
- Generator 1 is on-line and dispatched to full output, its dispatchable range is 100 MW
- Generators 2 and 3 are both off-line; they are both 20 MW quick start CTs
- RCF A has a limit of 100 MW with the actual flow at 95 MW



Stage 1 - Energy Prices at the RTO Border (Proxy Bus Prices)

The proxy bus prices will be calculated for each stage of the congestion management example. These examples illustrate that the proxy bus prices will move in the same direction as the constrained bus prices when the RCF is binding in both RTO security-constrained economic dispatches. The LMPs throughout both RTOs are equal to their System Marginal Price so long as the RTOs are unconstrained (no binding constraint resulting in redispatch of generation). This example also ignores marginal losses to simplify the illustration.



Stage 2 - Transmission Constraint Initialization

The RTO B (Monitoring RTO) dispatch software is projecting that the flow on Flowgate A is increasing and that ***9 MW of flow relief*** will be required. (Note: The 9 MW is derived from RTO B's look-ahead dispatch software along with a parallel path evaluation). The security-constrained dispatch solution for RTO B results in both Generator 2 and Generator 3 being dispatched; the system marginal price for RTO B remains at $40/MWh. Generator 3 is the most cost effective unit to control the constraint.

The Flowgate A constraint shadow price for RTO B will be equal to:

(Gen 2 Offer Price – System Marginal Price for RTO B)/(Generator 2 GLDF on Constraint)

($60/MWh-$40/MWh) /-0.20 = -$100/MW of Flow Relief.[4]

---

[4] The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 2 drives the constraint shadow price because it has the highest offer and the lowest GLDF.

The LMP for Gen 2 will be:

System Marginal Price for RTO B + (Gen 2 GLDF)(RTO B Shadow Price)

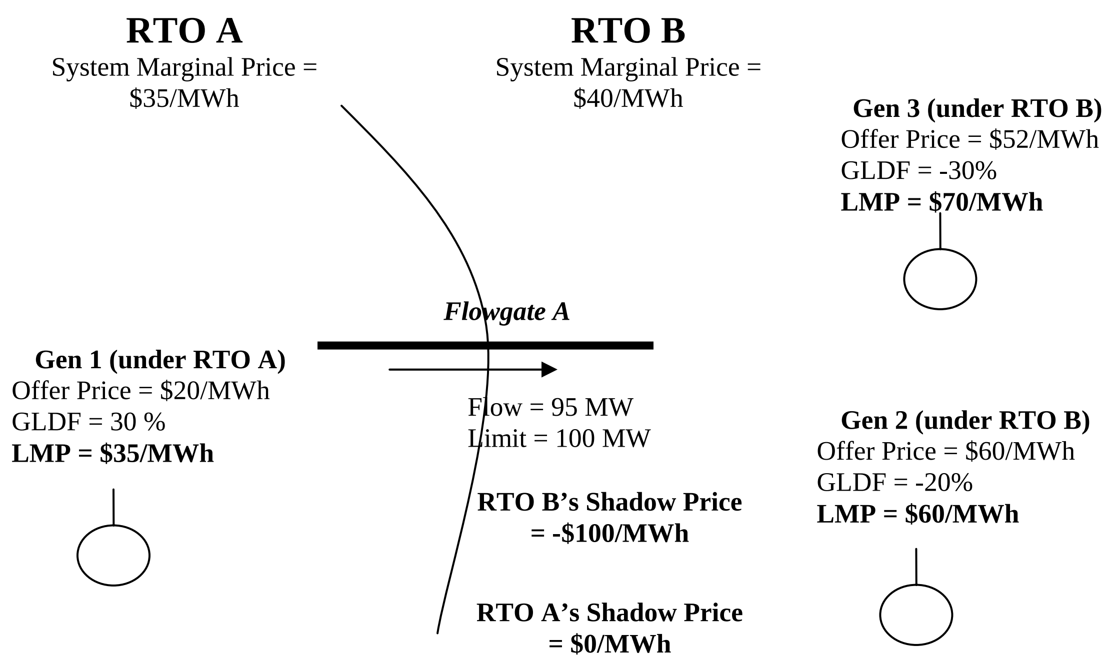
\$40/MWh + (-.2)(-\$100/MWh flow relief) = \$60/MWh

The LMP for Gen 3 will be:

System Marginal Price for RTO B + (Gen 3 GLDF)(RTO B Shadow Price)

\$40/MWh + (-.3)(-\$100/MWh flow relief) = \$70/MWh

The conditions for Stage 2, the initial transmission constrained scenario, are as follows:



Stage 2 - Energy Prices at the RTO Border (Proxy Bus Prices)

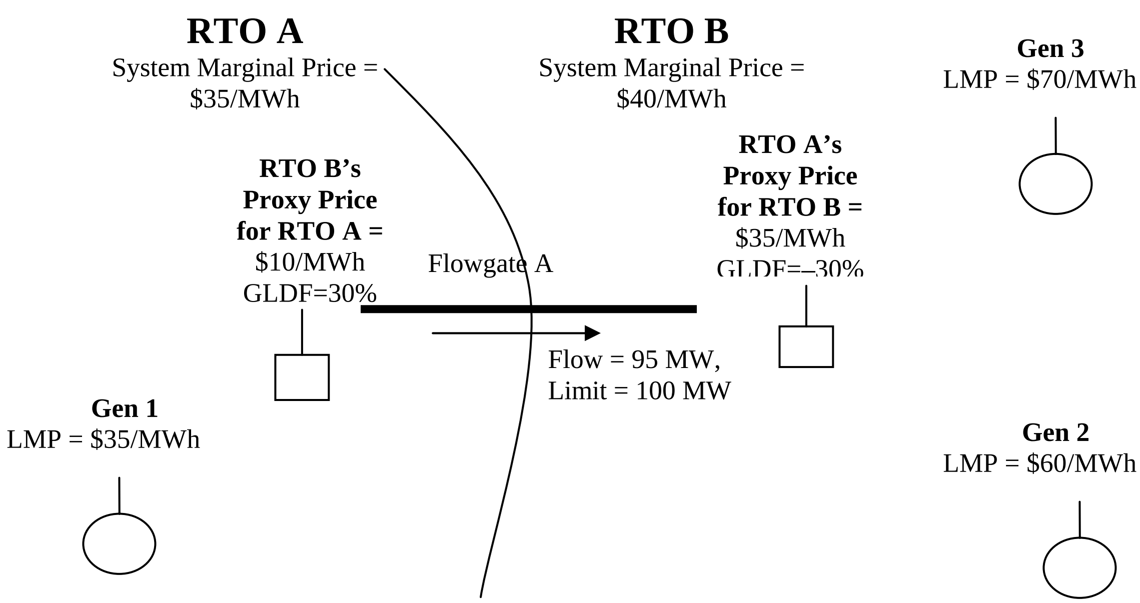
The proxy bus price for RTO A as calculated by RTO B will include the impact of the constraint on Flowgate A.

- Since the constraint is not binding in RTO A in Stage 2, the proxy price for RTO B as calculated by RTO A will remain at the system marginal price of RTO A.
- Since the proxy bus prices for each RTO reflect the value of imports or exports from the neighboring RTO, these proxy prices will be set by the system marginal price in the RTO that is calculating the proxy price.

RTO B's Proxy price for RTO A is as follows:

System Marginal Price for RTO B + (Proxy bus GLDF)(RTO B Shadow Price)

$40/MWh + (.3)(-$100/MWh flow relief) = $10/MWh



Stage 3 – First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Monitoring RTO)

- RTO B notifies RTO A of the transmission constraint Condition on Flowgate A
- RTO A enters the constraint into its security-constrained dispatch software with the current flow equal to the limit. (The current flow equals 35 MW in this case.) Since RTO A's load is growing, the constraint binds. (Assume Firm Flow is 40 MW.)

Flowgate A constraint shadow price for RTO A will be equal to:

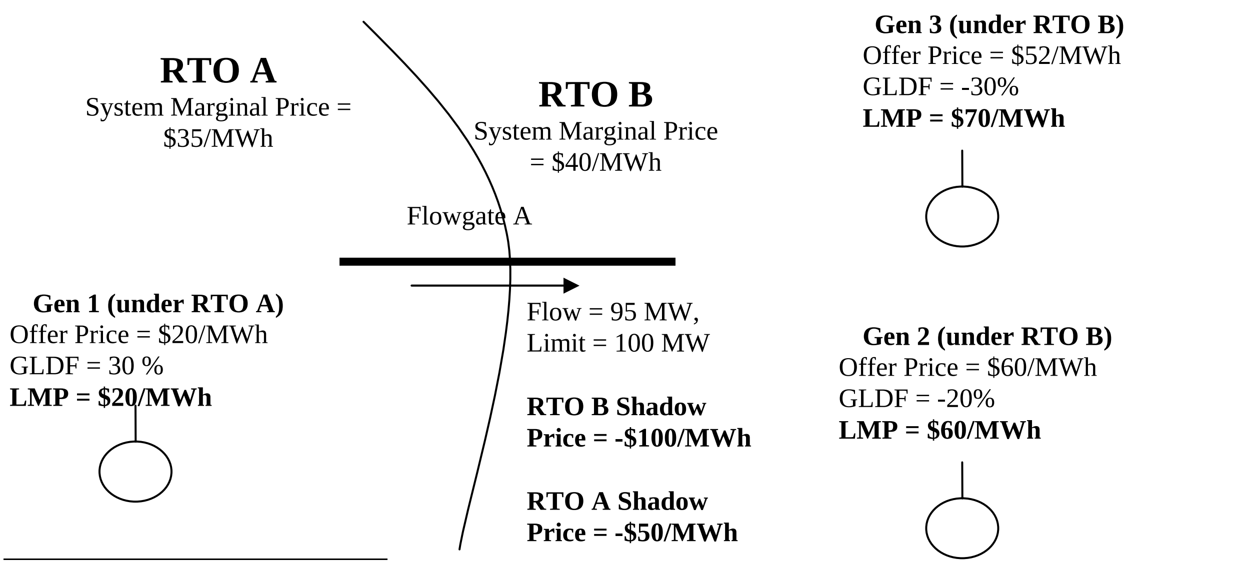
(Gen 1 Offer Price – System Marginal Price for RTO A)/(Gen 1 GLDF on Constraint)

($20/MWh-$35/MWh) /0.30 = -$50/MW of Flow Relief.[5]

The LMP for Gen 1 will be:

System Marginal Price for RTO A + (Gen 1 GLDF)(RTO A Shadow Price)

$35/MWh + (.3)(-$50/MWh flow relief) = $20/MWh



[5] The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 2 drives the constraint shadow price because it has the highest offer and the lowest GLDF.

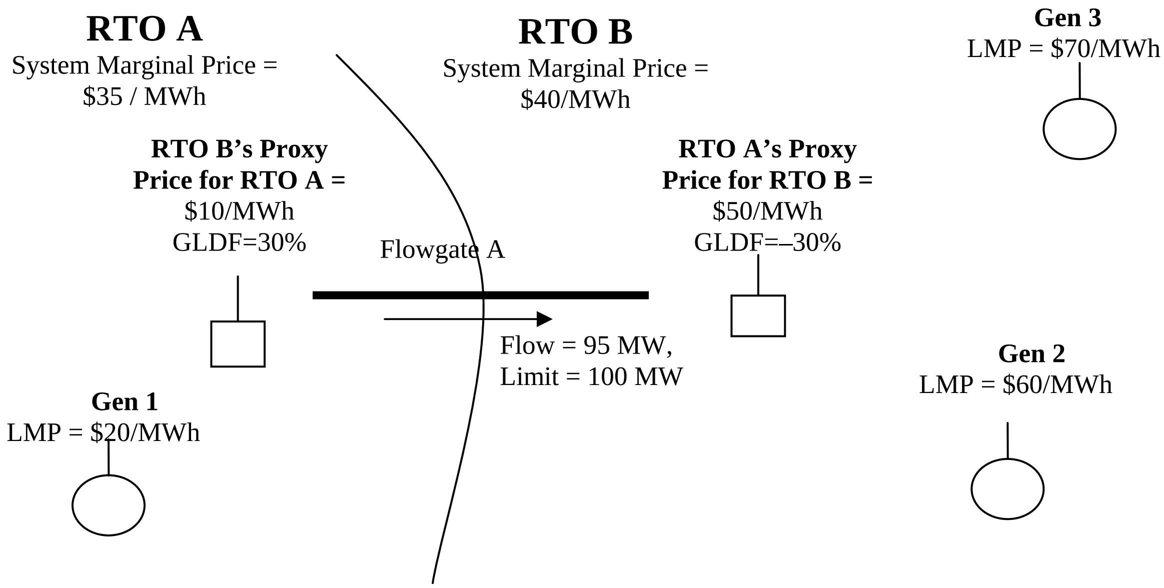
Stage 3 - Energy Prices at the RTO Border (Proxy Bus Prices)

The proxy bus price for RTO A as calculated by RTO B, will include the impact of the constraint on Flowgate A. Since the constraint is now binding in RTO A in stage 3, the proxy price for RTO B as calculated by RTO A will include impact of the constraint on Flowgate A.

RTO A's Proxy price for RTO B is as follows:

System Marginal Price for RTO A + (Proxy bus GLDF)(Shadow Price)

$35/MWh + (-.3)(-$50/MWh flow relief) = $50/MWh



Stage 4 – First Coordinated Interregional RTO Dispatch Cycle (Constraint Binds in Non-Monitoring RTO)

RTO B analyzes the constraint shadow price information and determines that RTO A has a more economical alternative to provide the Flow Relief than is currently being obtained by operating Generator 2 out of merit. The analysis results in RTO B requesting RTO A to provide 4 MW more of Flow Relief to enable Generator 2 to come offline.

RTO A agrees and lowers its limit on Flowgate A to 31 MW in its dispatch software.

RTO B requests Generator 2 to come off-line, because it will no longer be required to control the Flowgate A limit.

The Flowgate A constraint shadow price for RTO B will be equal to:

(Gen 3 Offer Price – System Marginal Price for RTO B)/(Generator 3 GLDF on Constraint)

($52/MWh-$40/MWh) /-0.30 = -$40/MW of Flow Relief.[6]

The LMP for Gen 2 will be:

System Marginal Price for RTO B + (Gen 2 GLDF)(RTO B Shadow Price)

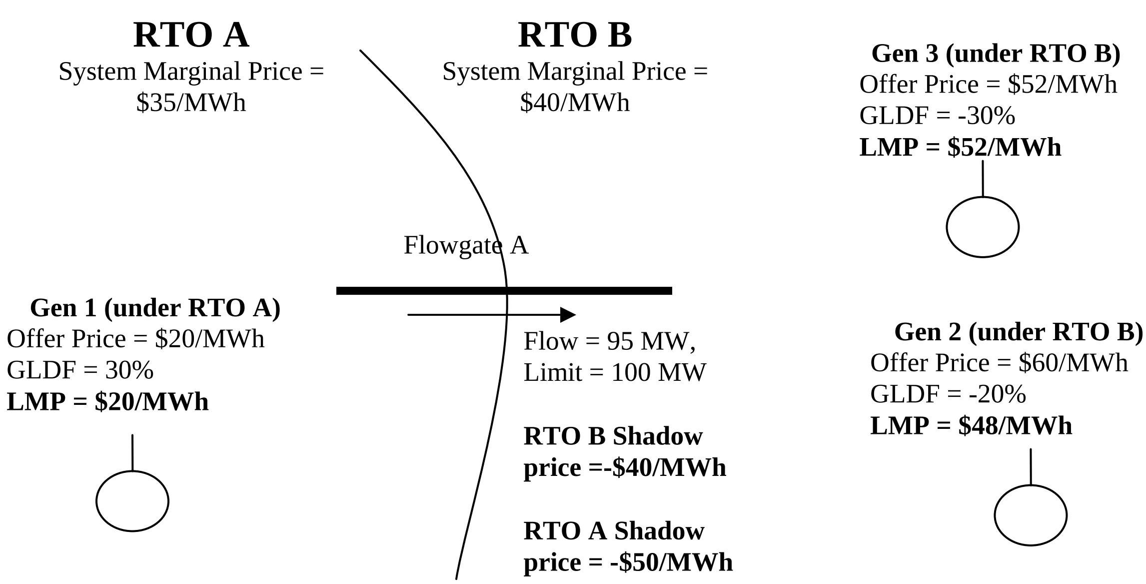
$40/MWh + (-.2)(-$40/MWh flow relief) = $48/MWh

The LMP for Gen 3 will be:

System Marginal Price for RTO B + (Gen 3 GLDF)(RTO B Shadow Price)

$40/MWh + (-.3)(-$40/MWh flow relief) = $52/MWh

The conditions for Stage 4 are as follows:



6 The transmission constraint shadow price is calculated based on the difference between the constrained on generator offer price and the system marginal price. This difference is then divided by the GLDF of the generator on the binding constraint. In this case, Generator 3 drives the constraint shadow price because it is the only unit online for the constraint.

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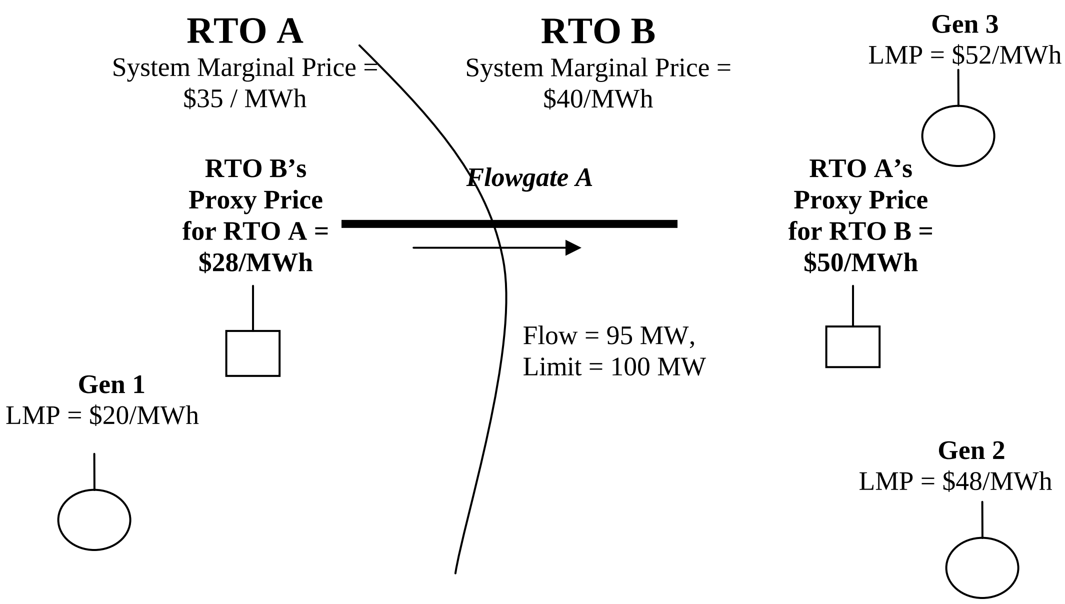
Stage 4 - Energy Prices at the RTO Border (Proxy Bus Prices)

The proxy bus price for RTO A, as calculated by RTO B, will include the impact of the constraint on Flowgate A. Since the constraint remains binding in RTO A in Stage 4, the proxy price for RTO B as calculated by RTO A will include impact of the constraint on Flowgate A.

RTO B's Proxy price for RTO A is as follows:

System Marginal Price for RTO B + (Proxy bus GLDF)(RTO B Shadow Price)

\$40/MWh + (.3)(-\$40/MWh flow relief) = \$28/MWh



Stage 5 – Ongoing Coordinated Dispatch Cycles

As the constrained operations progress, the RTOs will periodically verify that the constrained operations are coordinated by ensuring that the constraint shadow prices are reasonably close for the given constrained scenario.

In this case, the RTO A shadow price is $50/MWh and the RTO B shadow price is $40/MWh, which indicates that the system is optimally coordinated for the given constrained condition.

Settlement calculations

Stages 4 and 5 are the steady state situation integrated over an hour.

Firm Flow entitlement for RTO A on Flowgate A per the example = 40MW

Real-Time Market Flow MW by RTO A on Flowgate A = 31MW (requested by RTO B)

RTO A Shadow Price on Flowgate A = -$50/MWh

Payment (RTO B to RTO A) = ((Firm Flow Entitlement MW + Approved MW) – Real-Time Market Flow MW) * Transmission Constraint Shadow Price in Non-Monitoring RTOs Dispatch Solution

Payment (RTO B to RTO A) = ((40/MWh + 0) -31/MWh)*-$50/MWh

Payment (RTO B to RTO A) = $450

7 Evolution of the Market-to-Market Coordination Process

An evaluation of the feasibility of adding a more automated integrated approach to the Real-Time market redispatch will be performed as part of the implementation process. The Monitoring and Non-Monitoring RTOs, for example, could utilize each other's exchanged shadow prices as maximums for their individual redispatch limits. This would force the shadow prices to converge on each other through an automated iterative process. In addition to the redispatch of units within each market to control the transmission congestion problems at the RTO market borders, the market-to-market congestion coordination process could include adjustment of the interchange between the markets based on the participant load bids and generation offers submitted into each RTO's market. This coordination process would allow the constraints between the two control areas to be efficiently managed. It would also more efficiently manage the dispatch of control area to control area schedules when transmission constraints between the areas are not binding by making full use of the generation offers and load bids in each market. .

Following the implementation of the Real-Time market-to-market congestion coordination process in this ICP, the potential exists to implement an even more tightly integrated PJM/MISO energy marketplace. The evolution of the interregional markets could transition into the implementation of a single energy product and a single FTR product across both market regions.

The most likely next step would be to create an iterative clearing mechanism that would result in full coordination of the Day-Ahead energy markets and Real-Time energy markets by performing joint security-constrained economic dispatch through an iterative approach. This stage would essentially create a single energy marketplace across both RTOs. The iterative dispatch process would require a high level of integration and data transfer between the RTOs on both a Day-Ahead and Real-Time basis. Further evolution could involve implementing a single Day-Ahead energy market and a single real-time energy market across the entire footprints of both markets. This would require a single Day-Ahead market clearing engine and a single Real-Time Market-clearing engine. Both of these steps will require substantial software development. It is expected that an evaluation of the benefits and the feasibility of these steps will be performed to determine how to proceed after the initial market to market coordination is implemented.

Appendix A: Definitions

Any undefined, capitalized terms used in this ICP shall have the meaning: (i) provided in the Joint Operating Agreement between PJM and Midwest ISO, or in the CMP, or (ii) given under industry custom and, where applicable, in accordance with good utility practices.

Monitoring RTO	The RTO that has the primary responsibility for monitoring and control of a specified Reciprocal Coordinated Flowgate
Non-Monitoring RTO	The RTO that does not have the primary responsibility for monitoring and control of a specified Reciprocal Coordinated Flowgate, but does have generation that impacts that RCF by the NERC approved threshold (currently, 5% or greater)
Firm Flow	The estimated impacts of firm Network and Point-to-Point service on a particular Coordinated Flowgate.
Flow Relief	The reduction in the MW flow on an RCF that is caused by the generation redispatch as a result of the binding transmission constraint
Market Flow	The flow in MW on an RCF that is caused by all generation deliveries to load in the RTO footprint.
Reciprocal Coordinated Flowgate (RCF)	A coordinated flowgate for which Reciprocal Entities have generation that has a GLDF on the flowgate at or above the NERC approved threshold (currently, 5% or greater)
Requesting RTO	RTO that is requesting an increase in their Firm Flow Entitlement in the Day-Ahead energy market coordination procedures. A Requesting RTO may be a Monitoring RTO or a Non-Monitoring RTO with respect to a given RCF in Real Time.
Responding RTO	RTO that is responding to a request to reduce their Firm Flow Entitlement in the Day-Ahead energy market coordination procedures. A Responding RTO may be a Monitoring RTO or a Non-Monitoring RTO with respect to a given RCF in Real Time