ATTACHMENT 3

Interregional Coordination Process

Version 2.0

Deleted: 1.8

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

Deleted: Financial Transmission Rights

Formatted: Indent: Left: 0 pt, Hanging: 36 pt

Deleted: Auction

Deleted: Coordination

Deleted: 7

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.

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

Deleted: **FTR**
Deleted: FTRs
Deleted: allocation and

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 to be good functional indicators for the market-to-market coordination, 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 RTOs' 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.

Deleted: to function properly

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 prices for the other is 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.

Deleted: defined on the RTO border,

Deleted: and the proxy bus prices are actually the same or

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 RTO's 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.

Deleted: ¶
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.

4. 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:

Deleted: 5.

- Constraint Shadow Price ($/MW) - output of the RTOs 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.

Deleted: <#>Current Market Flow contribution by the Monitoring RTO on RCF (MW) - output of the Real-Time market software.¶

5. The Non-Monitoring RTO will enter the RCF into its security-constrained dispatch software, setting the flow limit on the RCF equal to its current market flow minus the relief requested by the Monitoring RTO.

   (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.

6. If the Non-Monitoring RTO has sufficient generation to be redispatched, it will redispatch its generation to the control the RCF until one of the following conditions is reached:

   (a) The Non-Monitoring RTO has provided the relief requested by the Monitoring RTO.

   (b) The Non-Monitoring RTO has provided relief at a cost as high as the current shadow price from the Monitoring RTO.

Formatted: Indent: Left: 72 pt, Hanging: 36 pt

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

Formatted: Indent: Left: 36 pt, Hanging: 36 pt

Formatted: Bullets and Numbering

- 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 RTO's Real-Time market software.

Deleted: 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. ¶

Deleted: 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.¶

8. 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 continue to control the RCF respecting the appropriate rating of the facility.

9. As the relief provided by the Non-Monitoring RTO is realized in the RCF, the Monitoring RTO can control the RCF at a lower shadow price since less relief is needed from the Monitoring RTO. The updated shadow price will be sent to the Non-Monitoring RTO. The Non-Monitoring RTO will then control the RCF using the latest shadow price from the Monitoring RTO as the shadow price limit.

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 shadow prices of the two RTOs will eventually converge towards the most cost-effective redispatch solution provided both RTOs have sufficient redispatch capability. The information transferred via these data exchanges will be retained to provide 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.

Deleted: 9

Deleted: 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.

Deleted: ¶

Deleted: purpose

Deleted: of

Deleted: to maintain the shadow price coordination over time and to

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).

---

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.

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 0800 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.

   Deleted: 0700

2. If the Responding RTO agrees to provide the limit reduction, it will communicate the approved amount to the Requesting RTO by 1000 EST.

   Deleted: 0800

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 Annual Revenue Rights (ARR) Allocation/Financial Transmission Rights (FTR) Auction Coordination

Deleted: Financial Transmission Rights

The allocation of ARR and FTR products in each marketplace must recognize the flowgate entitlement that exists in adjacent markets. The ARR allocation and FTR 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 ARRs via Annual ARR Allocation award, and award FTRs via Annual and Monthly FTR Auction to Network and Firm Transmission customers subject to their participation and simultaneous feasibility test that determines the amount of transmission capability that exists to support the ARRs and FTRs.

Deleted: FTR
Deleted: FTR
Deleted: (or
Deleted:)
Deleted: (or Auction)
Deleted: a

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 ARR Allocation and FTR 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 ARR Allocation and the FTR Auction across both RTOs will recognize the reciprocal transmission utilization that exists for Network and Firm transmission customers in both markets.

Deleted: FTR
Deleted: a
Deleted: a
Deleted: FTR
Deleted: a

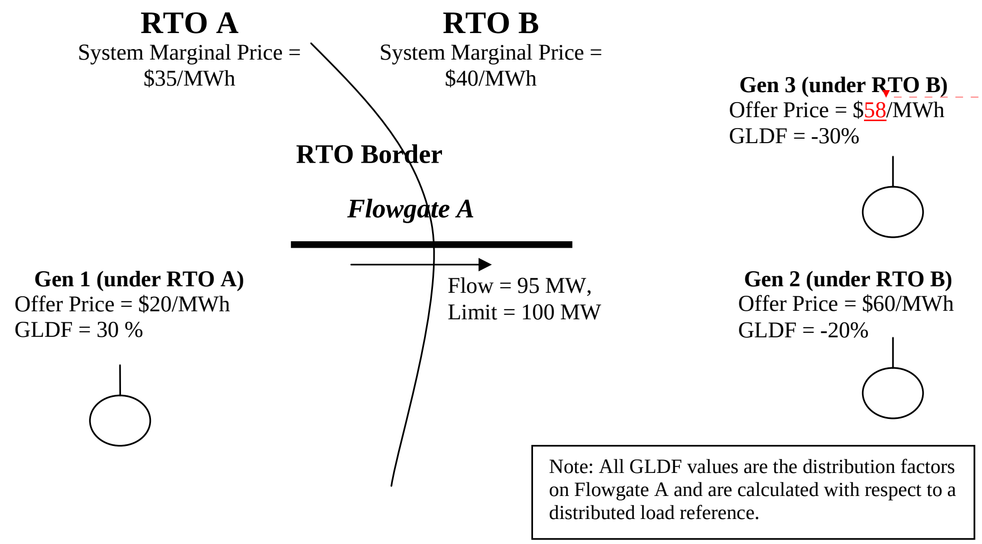
6 Coordination Example

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

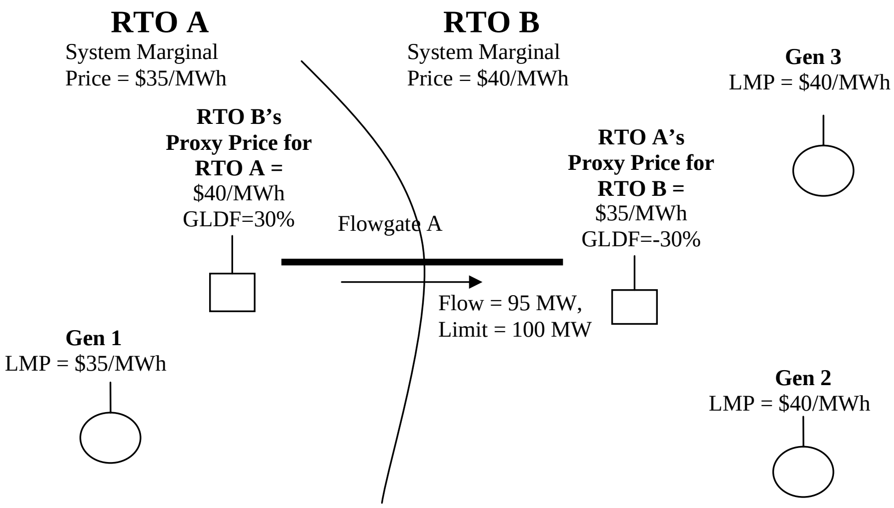
- Marginal Losses are not utilized in this example for ease of understanding
- RTO A is the Non-Monitoring RTO, its system marginal price is $35/MWh
- RTO B is the Monitoring RTO, its system marginal price is $40/MWh
- Generator 1 is on-line and dispatched to full output, its dispatchable range is 100 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



Deleted: 52

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)

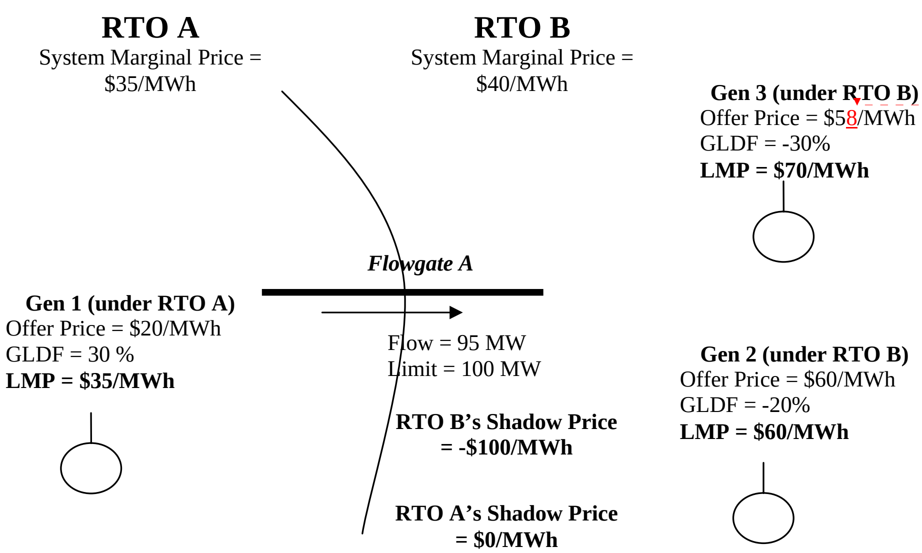
$40/MWh + (-.2)(-$100/MWh flow relief) = $60/MWh

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:



Deleted: 2

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

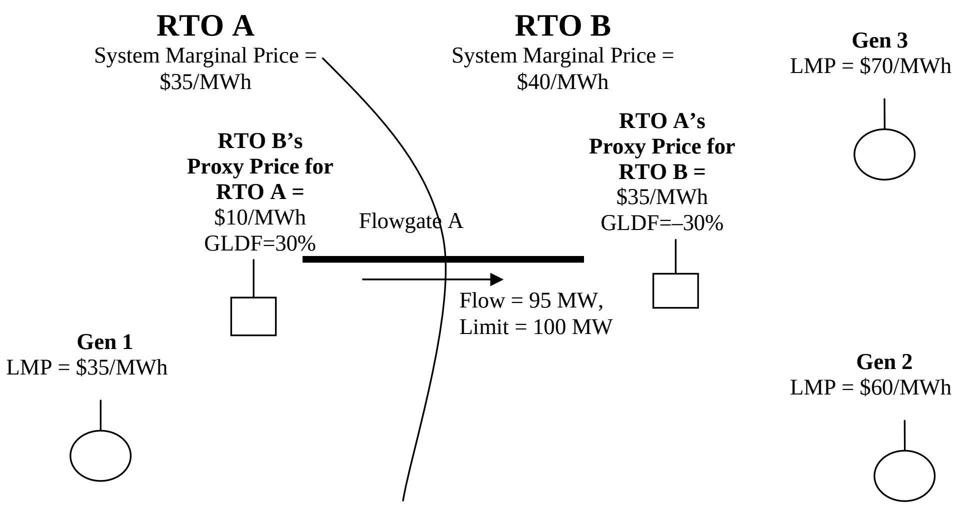
The proxy bus price for RTO A as calculated by RTO B will include the impact of the constraint on Flowgate A.

- 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. Initially RTO B requests RTO A to maintain its current market flow on Flowgate A. RTO B sends its latest shadow price of -$100/MWh to RTO A.
- RTO A enters the constraint into its security-constrained dispatch software with the current flow equal to the limit using -$100/MWh as its shadow price limit. (The current flow equals 35 MW in this case.) Since RTO A's load is growing, the constraint binds with a shadow price less than the -$100/MWh limit. (Assume Firm Flow is 40 MW.)

Deleted: .

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

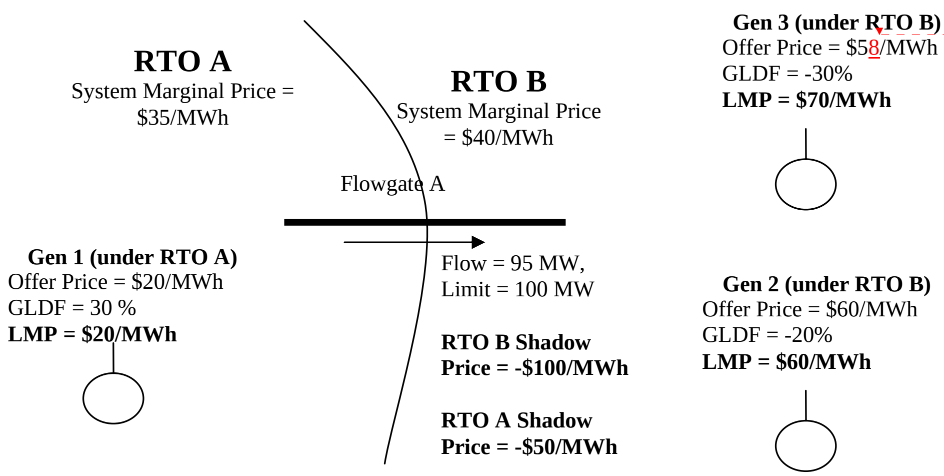
(Gen 1 Offer Price – System Marginal Price for RTO A)/(Gen 1 GLDF on Constraint)

($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



Deleted: 2

[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. The resulting shadow price of -$50/MWh is less than the limit of -$100/MWh from the Monitoring RTO A.

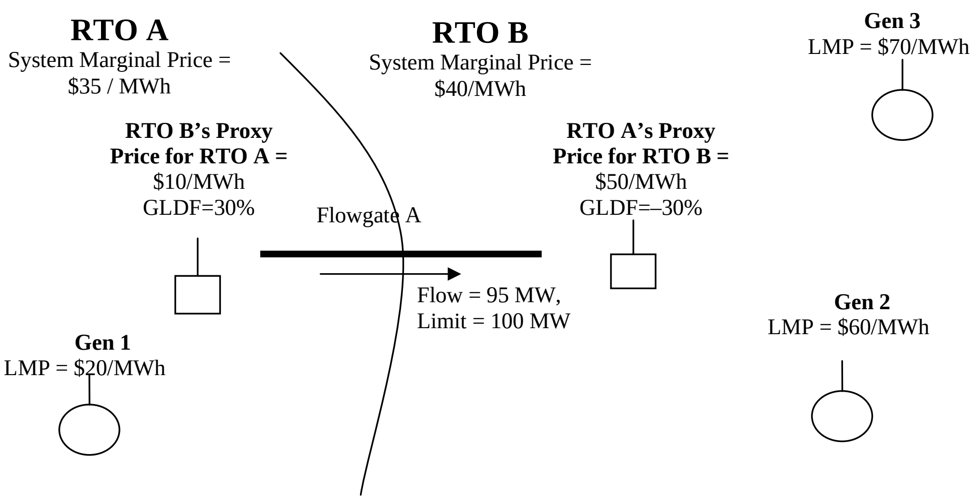
Stage 3 - Energy Prices at the RTO Border (Proxy Bus Prices)

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 is able to reduce its market flow on Flowgate A to the desired 31 MW limit in its dispatch software. RTO A can achieve the requested relief by lowering Gen 1 while observing the shadow price limit from RTO B.

Deleted: agrees and lowers

Deleted: limit

Deleted:

After the flow on Flowgate A is reduced by the redispatch action from RTO A,. 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)

(\$58/MWh-\$40/MWh) /-0.30 = -\$60/MW of Flow Relief.[6]

Deleted: 52
Deleted: 40

The LMP for Gen 2 will be:

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

\$40/MWh + (-.2)(-\$60/MWh flow relief) = \$52/MWh

Deleted: 40
Deleted: 48

The LMP for Gen 3 will be:

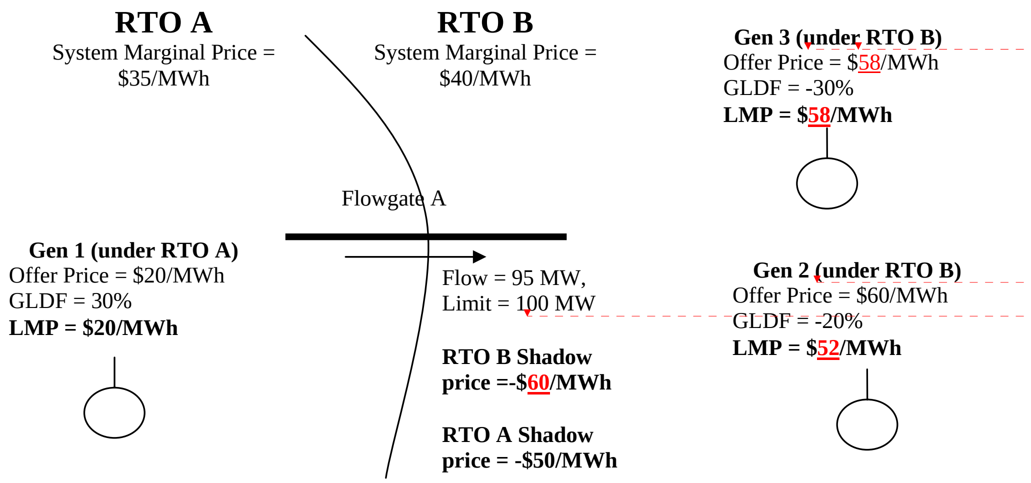
System Marginal Price for RTO B + (Gen 3 GLDF)(RTO B Shadow Price)

\$40/MWh + (-.3)(-\$60/MWh flow relief) = \$58/MWh

Deleted: 40
Deleted: 52

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.

The conditions for Stage 4 are as follows:



Deleted: 52

Deleted: 52

Deleted: 48

Deleted: 40

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

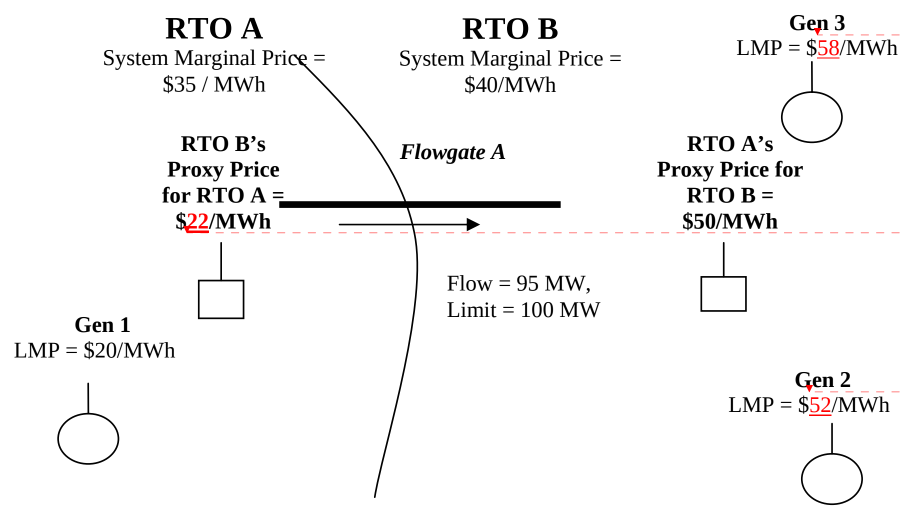
The proxy bus price for RTO A, as calculated by RTO B, will include the impact of the constraint on Flowgate A. Since the constraint remains binding in RTO A in Stage 4, the proxy price for RTO B as calculated by RTO A will include impact of the constraint on Flowgate A.

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)(-$60/MWh flow relief) = $22/MWh

Deleted: 40
Deleted: 28



Deleted: 52
Deleted: 28
Deleted: 48

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 $60/MWh, which indicates that the system is optimally coordinated for the given constrained condition.

Deleted: 40

The RTO B's proxy bus price for RTO A is $22/MWh which is very close to the LMP at Gen 1 bus ($20/MWh) in RTO A. The RTO B's proxy bus for RTO A and the Gen 1 bus both have +30% GLDF on Flowgate A. One of the objectives of the market-to-market coordination is to achieve price convergence for buses with similar GLDFs across the RTO border. Similarly, the RTO A's proxy bus price for RTO B is $50/MWh which is reasonably close to the LMP at Gen 3 bus ($58/MWh) in RTO B. The RTO A's proxy bus for RTO B and the Gen 3 bus both have -30% GLDF on Flowgate A.

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

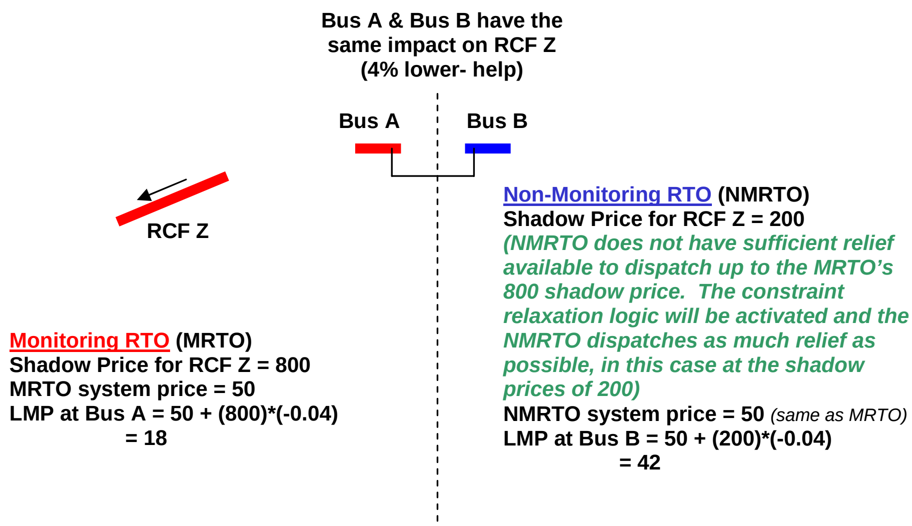
Payment (RTO B to RTO A) = ((40/MWh + 0) -31/MWh)*-$50/MWh

Payment (RTO B to RTO A) = $450

7 When one of the RTOs does not have sufficient redispatch

Under the normal market-to-market implementation, sufficient redispatch for a RCF may be available in one RTO but not the other. When this condition occurs, in order to ensure a physically feasible dispatch solution is achieved, the RTO without sufficient redispatch will activate logic in its dispatch algorithm which redispatches all available generation in the RTO to control the RCF to a “relaxed” limit. Then this RTO calculates the shadow price for the RCF using the available redispatch which is limited by the maximum physical control action inside the RTO. Because the magnitude of the shadow price in this RTO cannot reach that of the other RTO with sufficient redispatch, unless further action is taken, there will be a divergence in shadow prices and the LMPs at the RTO border.

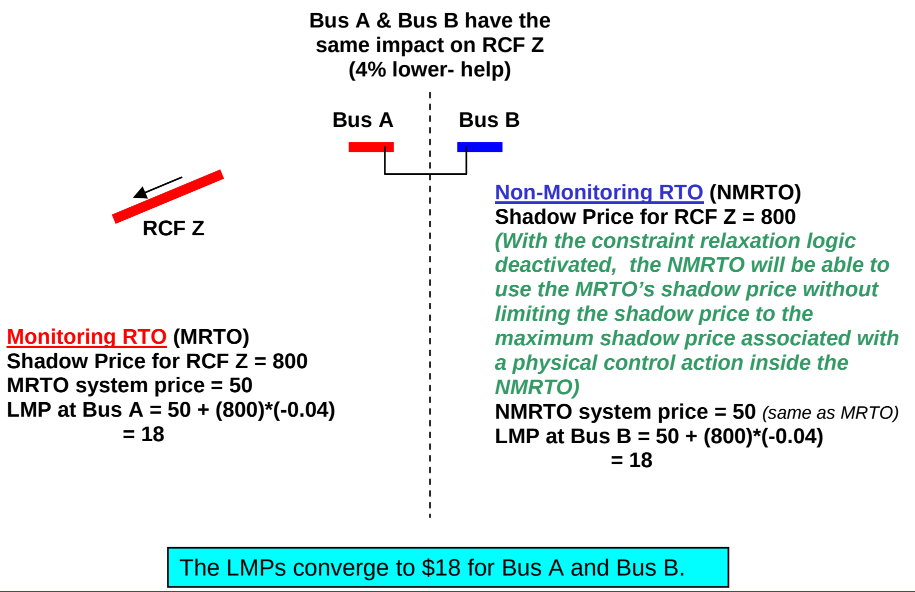
The example below illustrates how the LMPs at the RTO border diverge under this condition:



The LMPs differ by $24 even though Bus A and Bus B are electrically close to each other.

A special process is designed to enhance the price convergence under this condition. If the Non-Monitoring RTO cannot provide sufficient relief to reach the shadow price of the Monitoring RTO, the constraint relaxation logic will be deactivated. The Non-Monitoring RTO will then be able to use the Monitoring RTO's shadow price without limiting the shadow price to the maximum shadow price associated with a physical control action inside the Non-Monitoring RTO. With the RCF shadow prices being the same in both RTOs, their resulting bus LMPs will converge in a consistent price profile.

The following example illustrates how the price convergence can occur:



This process also allows price convergence when the Non-Monitoring RTO has a higher shadow price than the Monitoring RTO

Deleted: 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 softw ... [1]

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

ATTACHMENT 4

CROSS-BORDER GRANDFATHERED PROJECTS

Arrowhead – Gardner Park 345 kV Line

AEP 765 kV Cloverdale Line

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.