Seams Operating Agreement
Between the

Midcontinent Independent System Operator, Inc.
And
Manitoba Hydro

Seams Operating Agreement
Between the
Midcontinent Independent System Operator, Inc.
And
Manitoba Hydro

ARTICLE I
RECITALS

This Seams Operating Agreement ("Agreement") dated this 25th day of September 2006, is hereby executed by and between the Midcontinent Independent System Operator, Inc. ("MISO") MISO and Manitoba Hydro. Manitoba Hydro and the MISO may be individually referred to herein as "Party" or collectively as "Parties."

WHEREAS Manitoba Hydro is a Canadian Crown corporation incorporated pursuant to the provisions of *The Manitoba Hydro Act* (Revised Statutes of Manitoba 1987, chapter H190) that owns and operates electric transmission facilities in the Province of Manitoba, Canada;

AND WHEREAS the MISO is a Delaware non-stock, not-for-profit corporation incorporated pursuant to Title 8, Chapter 1 of the laws of the State of Delaware of the United States of America and established by U.S. transmission facility owners pursuant to the MISO Agreement;

AND WHEREAS the MISO is an RTO that provides operating and reliability functions with respect to electrical transmission systems located in portions of the Midwest United States of America, which are interconnected with the transmission system of Manitoba Hydro;

AND WHEREAS the MISO and Manitoba Hydro entered into a Coordination Agreement on September 27, 2001, to among other things, coordinate congestion management procedures for the transmission facilities comprising the systems of the MISO and Manitoba Hydro ("Combined Systems"); primarily through the use of transmission service curtailments known as TLR;

AND WHEREAS effective April 1, 2005 the MISO operates an energy market based on locational marginal pricing to facilitate energy transactions and to manage transmission congestion primarily through the use of economic redispatch on the MISO system rather than TLR;

AND WHEREAS Manitoba Hydro does not intend to operate an energy market employing economic redispatch in Manitoba as a method of managing transmission congestion;

AND WHEREAS the Parties desire to continue to coordinate congestion management procedures across the market to non-market interface ("seam") between the MISO and Manitoba;

AND WHEREAS Section 6.4 of the Coordination Agreement as amended on January 27, 2005, obligates the parties to enter into good faith negotiations to develop congestion management procedures to coordinate Manitoba Hydro's use of TLR with the MISO's use of economic redispatch;

AND WHEREAS the Parties desire to amend this Agreement to discontinue the practice of joint MISO-Manitoba Hydro impacts, limits and allocations for congestion management purposes and to clarify the methodology for calculating separate Manitoba Hydro impacts, limits and allocations;

AND WHEREAS the Parties on May 26, 2016 amended the Agreement to replace the Congestion Management Process attached hereto as Attachment B and make minor corresponding changes to the Agreement itself;

AND WHEREAS the Parties on December 15, 2016, amended the Agreement to incorporate certain obligations with respect to resource planning; and

NOW, THEREFORE, for the consideration stated herein, and for other good and valuable consideration, the receipt of which hereby is acknowledged, the Parties hereby agree as follows:

ARTICLE II
ABBREVIATIONS, ACRONYMS, DEFINITIONS And RULES of CONSTRUCTION

2.1 Abbreviations and Acronyms.

2.1.1 "ATC/AFC" shall mean Available Transfer Capability/Available Flowgate Capability, as those terms are used in the electric utility industry.

2.1.2 "CBM" shall mean Capacity Benefit Margin.

2.1.3 "CIM" shall mean Common Information Model.

2.1.4 "EFOR" shall mean Equivalent Forced Outage Rate, as defined by NERC.

2.1.5 "EMS" shall mean the Energy Management Systems utilized by the Parties to manage the flow of energy within their regions.

2.1.6 "FERC" shall mean the U.S. Federal Energy Regulatory Commission or any successor agency thereto.

2.1.7 "FTP" shall mean the standardized file transfer protocol for data transfer.

2.1.8 "ICCP/ISN" shall mean those common communication protocols adopted to standardize information transfer.

2.1.9 "IDC" shall mean the NERC Interchange Distribution Calculator used for identifying and requesting congestion management relief.

2.1.10 "MW" shall mean megawatt of power.

2.1.11 "NERC" shall mean the North American Electricity Reliability Council or its successor organization.

2.1.12 "OASIS" shall mean the Open Access Same-Time Information System required by FERC for the posting of market and transmission data on the Internet.

2.1.13 "OATT" shall mean the applicable Open Access Transmission Tariff.

2.1.14 "PMAX" shall mean the maximum generator real power output reported in MWs on a seasonal basis.

2.1.15 "PMIN" shall mean the minimum generator real power output reported in MWs on a seasonal basis.

2.1.16 "QMAX" shall mean the maximum generator reactive power output reported in MVARs at full real power output of the unit.

2.1.17 "QMIN" shall mean the minimum generator reactive power output reported in MVARs at full real power output of the unit

2.1.18 "RCF" shall mean Reciprocal Coordinated Flowgate.

2.1.19 "RTO" shall mean Regional Transmission Organization.

2.1.20 "TLR" shall mean the NERC Transmission Loading Relief Procedures used in the Eastern Interconnection as specified in NERC Operating Policies.

2.1.21 "TRM" shall mean the Transmission Reliability Margin.

2.1.22 "TTC" shall mean Total Transfer Capability.

2.2 Definitions.

2.2.1 "Agreed Interest Rate" shall mean the rate of two percent per annum plus the prime lending rate per annum in effect and applicable to each day of the interest period. The prime lending rate shall be the rate of interest per annum, publicly announced from time to time by the Royal Bank of Canada at its main office in the City of Winnipeg, Manitoba as its preferred lending rate of interest charged to its most creditworthy Canadian customers, whether or not such interest rate is actually charged by said bank to any customer. Notwithstanding the foregoing, in no event shall the Agreed Interest Rate ever exceed the maximum rate of interest allowed under Canadian Law.

2.2.2 "Agreement" shall mean this Agreement.

2.2.3 "Available Flowgate Capability" (AFC) or Available Transfer Capability (ATC) shall mean a measure of the transfer capability remaining on a Flowgate for further commercial activity over and above already committed uses. It is calculated as follows: Flowgate Rating, or TTC, less existing transmission commitments (including retail customer service), less a Capacity Benefit Margin (CBM), less a Transmission Reliability Margin (TRM), unless determined otherwise by NERC reliability standards or a government body with jurisdiction over reliability standards.

2.2.4 "Available Share of Flowgate Capability" (ASTFC) represents the share of total flowgate capacity that a particular entity has been allocated. This share of total flowgate capacity represents the maximum total impact that entity is allowed to have on that Flowgate and is converted to an ASTFC which represents how much Flowgate capability remains available on that Flowgate for use as transmission service.

2.2.5 "Canadian Law" shall mean the substantive common law of Canada as amended by and in addition to Canadian federal statutes and regulations and Manitoba provincial statutes; regulations, orders-in-council and applicable municipal by-laws.

2.2.6 "Capacity Benefit Margin" (CBM) shall mean the amount of firm transmission transfer capability preserved by the transmission provider for load-serving entities (LSEs), whose loads are located on that transmission provider's system, to enable access by the LSEs to generation from interconnected systems to meet generation reliability requirements. Preservation of CBM for an LSE allows that entity to reduce its installed generating capacity below that which may otherwise have been necessary without interconnections to meet its generation reliability requirements. The transmission transfer capability preserved as CBM is intended to be used by the LSE only in times of emergency generation deficiencies.

2.2.7 "Confidential Information" shall have the meaning stated in Section 13.1.1.

2.2.8 "Congestion Management Process" shall refer to the process and procedures set forth in the Congestion Management Process currently in effect between MISO and Manitoba Hydro (Attachment B to this Agreement).

2.2.9 "Control Area(s)" shall mean a system or systems to which a common automatic generation control scheme is applied in order to, among other things, maintain scheduled interchange with other control areas, within the limits of Good Utility Practice and maintain the frequency of the electric power systems within reasonable limits in accordance with Good Utility Practice.

2.2.10 "Coordinated Flowgate" or CF shall have the meaning set forth in the Protocols. A Coordinated Flowgate may be under the operational control of a third party.

2.2.11 "Coordination Agreement" shall mean the Agreement between the Parties dated January 27, 2005, as amended from time to time.

2.2.12 "Critical Facility" shall mean a facility that is identified in a Party's Operating Guide as impacting an Interconnection Reliability Operating Limit.

2.2.13 "Dispatchable Dynamic Schedule" is a mechanism that, in response to an offer made into the market, is utilized by a market entity using its Security Constrained Economic Dispatch 1) to dispatch another operating entity's generator or fleet of generators by establishing generator basepoints to meet its demand via an import dispatchable dynamic schedule that is associated with a NERC tagged transaction or 2) to dispatch its own generator or a fleet of generators by establishing generator basepoints to meet another operating entity's demand via an export dispatchable dynamic schedule that is associated with a NERC tagged transaction.

2.2.14 "Effective Date" shall have the meaning stated in Section 9.1.

2.2.15 "Energy Emergency" shall have the meaning ascribed thereto in the MISO Open Access Transmission and Energy Markets Tariff.

2.2.16 "External Asynchronous Resource (EAR)" is a Resource representing an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is supported within the Transmission Provider Region through Dynamic Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid.

2.2.17 "Firm Flow" shall mean the estimated impacts of firm transactions under Network Integration and Firm Point-to-Point Transmission Service on a particular Coordinated Flowgate.

2.2.18 "Flowgate" shall mean a representative modeling of a facility or group of facilities that may act as a constraint to power transfer on the bulk transmission system.

2.2.19 "Flowgate Rating" shall mean the Total Transfer Capability (TTC) of a Flowgate.

2.2.20 "Good Utility Practice" means any of the practices, methods and acts engaged in or approved by a significant portion of the electric utility industry during the relevant time period, or any of the practices, methods and acts which, in the exercise of reasonable judgment in light of the facts known at the time the decision was made, could have been expected to accomplish the desired result at a reasonable cost consistent with good business practices, reliability, safety and expedition. Good Utility Practice is not intended to be limited to the optimum practice, method, or act to the exclusion of all others, but rather to be acceptable practices, methods, or acts generally accepted in the region.

2.2.21 "Interconnection Reliability Operating Limit" shall have the same meaning as defined by NERC.

2.2.22 "Intellectual Property" shall mean any proprietary right provided under: (i) patent law; (ii) copyright law; (iii) trademark law; (iv) design patent or industrial design law; (v) semi-conductor chip or mask work law; and (vi) any other statutory provision or common law principle that may provide a right in either (a) ideas, formulae algorithms, concepts, inventions or know-how; or (b) the expression of such ideas, formulae algorithms, concepts, inventions or know-how.

2.2.23 "Intermittent Generation" shall mean a resource that cannot be scheduled and controlled to produce the anticipated energy.

2.2.24 "Market" shall mean the market structure contained in the MISO's Transmission and Energy Markets Tariff, as accepted by FERC.

2.2.25 "MISO" shall mean the Midcontinent Independent System Operator, Inc.

2.2.26 "MH-MISO Business Practices" shall mean a set of business practices jointly developed by Manitoba Hydro and The MISO in order to implement this Agreement.

2.2.27 "MMWG" shall mean the NERC Multi-Regional Modeling Working Group. The MMWG is responsible for developing a library of solved power flow models of the Eastern Interconnection for use by the Regions and their member systems in planning and evaluating future systems and current operating conditions.

2.2.28 "M2M Flowgate" shall have the meaning ascribed thereto in Appendix A of Attachment 3 of the Joint Operating Agreement between MISO and PJM Interconnection, LLC and Attachment 2 of the Joint Operating Agreement between MISO and Southwest Power Pool, Inc.

2.2.29 "Network Integration Transmission Service" shall have the same meaning as defined in the transmission tariff of the applicable Party.

2.2.30 "Notice" shall have the meaning stated in Section 14.10.

2.2.31 "Operating Guide" shall mean a written set of operating practices to be followed for transmission and generation operation, including implementing procedures, actions and sequences of actions to be taken to maintain operations within operating reliability criteria.

2.2.32 "Outages" shall mean the unavailability of transmission and/or generation facilities operated by the Parties, as described in Article VII of this Agreement.

2.2.33 "Party" or "Parties" refers to each party to this Agreement or both, as applicable.

2.2.34 "Point-to-Point Transmission Service" shall have the same meaning as defined in the transmission tariff of the applicable Party.

2.2.35 "Protocols" shall refer to the TTC/ATC/AFC Protocol and the Congestion Management Process (Attachments A and B to this Agreement).

2.2.36 "Reciprocal Coordinated Flowgate" (RCF) shall have the meaning set forth in the Protocols. An RCF may be under the operational control of one of the Parties, or may be under the operational control of another Reciprocal Entity, as defined in the Protocols.

2.2.37 "Reliability Coordinator" (RC) shall have the same meaning as defined in the Coordination Agreement between the Parties dated January 27, 2005 as amended from time to time.

2.2.38 "Reciprocal Entity" shall have the same meaning as defined in Attachment B to this Agreement.

2.2.39 "SCADA Data" shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC Policy 4.

2.2.40 "Total Transfer Capability" (TTC) is the amount of electric power that can be moved or transferred reliably from one study area to another study area of the interconnected transmission systems by way of all transmission lines (or paths) between those study areas under specified system conditions.

2.2.41 "TTC/ATC/AFC" Protocol refers to the Protocol governing collection of data related to the calculation of TTC and ATC (Attachment A to this Agreement).

2.2.42 "Transmission Owner" shall mean any entity defined as such under the MISO Open Access Transmission and Energy Markets Tariff.

2.2.43 "Transmission Reliability Margin" (TRM) shall mean the amount of transmission transfer capability necessary to provide reasonable assurance that the interconnected transmission network will be secure. TRM accounts for the inherent uncertainty in system conditions and the need for operating flexibility to ensure reliable system operation as system conditions change.

2.3 Rules of Construction.

2.3.1 No Interpretation Against Drafter. The Parties agree that each Party participated in the drafting of this Agreement and was represented therein by competent legal counsel. No rule of construction or interpretation against the drafter shall be applied to the construction or in the interpretation of this Agreement.

2.3.2 Meanings of Certain Common Words. The word “including” shall be understood to mean “including, but not limited to.” The word “Section” refers to the applicable section of this Agreement and, unless otherwise stated, includes all subsections thereof. The word “Article” refers to articles of this Agreement.

2.3.3 NERC Policies and Standards. All activities required to be carried out pursuant to this Agreement shall be implemented in a manner so as to meet or exceed the applicable NERC policies or standards as revised from time to time, to the extent permitted by Canadian Law. In the event of a conflict between this Agreement and NERC policies or standards (to the extent consistent with Canadian Law), the Parties shall engage in good faith negotiations to reconcile the inconsistency.

2.3.4 Protocol Documents. The TTC/ATC/AFC Protocol and the Congestion Management Process (“Protocols”) are hereby incorporated into this Agreement as Attachments A and B.

2.3.5 Scope of Application. Each Party will perform this Agreement in accordance with its terms and conditions. The MISO will perform this Agreement with respect to each Transmission Owner for which it administers transmission service.

2.3.6 Technical Terminology. Words not otherwise defined in this Agreement that have well known and generally accepted technical meanings are used herein in accordance with such recognized meanings.

ARTICLE III
OVERVIEW OF COORDINATION AND INFORMATION TRANSFER

3.1 Coordination of Operations.

The MISO, as the NERC Reliability Coordinator for Manitoba Hydro, shall perform its functions in accordance with this Agreement, the Coordination Agreement, NERC and regional reliability organization policies and standards (to the extent permitted by Canadian Law), Good Utility Practice and the MH-MISO Business Practices, as developed and modified by the Parties for the term of the Agreement.

3.2 Ongoing Review and Revisions.

The Parties have agreed to the coordination and transfer of data and information under this Agreement to ensure system reliability and efficient transmission service as systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and technology applicable to these systems and to the collection and transfer of data will change from time to time throughout the term of this Agreement. The Parties agree to periodically review, and as appropriate, enter into good faith negotiations to revise the requirements stated herein in response to such changes, including deleting, adding, or revising requirements in the Protocols and MH-MISO Business Practices.

3.3 Meaning of Requirement to Transfer or Provide Data.

The Parties acknowledge that as of the Effective Date of this Agreement the MISO is providing reliability coordination and tariff administration services to Manitoba Hydro pursuant to a Coordination Agreement between the Parties and, therefore, is collecting or is already in possession of certain data contemplated to be provided by Manitoba Hydro to the MISO by this Agreement. Accordingly, the Parties agree that to the extent that such services are still being provided throughout the term of this Agreement and the MISO is already in possession of certain data contemplated by this Agreement, the requirement to provide or transfer such data shall mean that Manitoba Hydro authorizes the use of such data by the MISO, in the form and for the purposes set forth in this Agreement. The Parties intend the collection, use and transfer of data and information under this Agreement to be a cooperative process subject to the confidentiality provisions in this Agreement. In the event that the Coordination Agreement is terminated, the Parties shall enter into good faith negotiations to revise this Agreement as necessary and shall continue to share data as required by applicable reliability standards, or Good Utility Practice.

3.4 Business Practices.

The Parties shall jointly develop MH-MISO Business Practices within a reasonable time following the Effective Date of this Agreement to address the procedures required for the effective implementation of this Agreement.

ARTICLE IV
TRANSFER OF INFORMATION AND DATA

4.1 Transfer of Operating Data.

The Parties shall transfer the following types of data and information:

(1) Real-Time and Projected Operating Data (4.1.1);
(2) SCADA Data (4.1.2);
(3) EMS Models (4.1.3); and
(4) Operations Planning Data (4.1.4).

4.1(a) Each Party shall provide the data identified in items (1) through (4) above to the other Party. MISO shall provide said data with respect to all Transmission Owners for which the MISO administers transmission service, and for Control Areas other than Manitoba Hydro for which the MISO acts as Reliability Coordinator on the Effective Date and during the term of this Agreement.

4.1(b) To ensure the accuracy of all critical operating data, each Party shall designate to the other Party's designated representative a contact to be available twenty-four (24) hours each day, seven (7) days per week, and an alternate contact to act in the absence or unavailability of the primary contact, to respond to any inquiries from the other Party. With respect to each contact and alternate, each Party shall provide the name, telephone number, e-mail address, and fax number. Each Party may change a designee from time to time by Notice to the other Party's designated representative.

4.1(c) The Parties agree to transfer data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. If any required data transfer format has not been agreed upon as of the Effective Date, or if a Party determines that an agreed format should be revised, a Party shall give Notice of the need for an agreed format or revision and the Parties shall jointly seek to complete development of the format within thirty (30) days of such Notice. Upon agreement, development shall be completed as soon as practical.

4.1.1 Real-Time and Projected Operating Data

The Parties shall transfer two categories of operating data, real-time information and projected information, as follows:

(a) The real–time operating information shall consist of:

(i) Generation status of the units, as telemetered or as derived from the unit breaker, in each Party's tariff or footprint;
(ii) Transmission line status, *i.e.*, status of switching devices associated with each end of the line;

(iii) Control Area demands;
(iv) Selected real-time telemetered bus loads where available;
(v) Scheduled use of transmission service reservations; and
(vi) Critical Facility limits.

(b) Projected operating information shall consist of:

(i) Planned hourly generation schedules;
(ii) Generating unit and transmission facilities maintenance schedules;
(iii) The planned operational start-up or change dates for any permanently added, removed or significantly altered transmission segments;
(iv) Points of interconnection between the two Parties that will be permanently removed or added (this information to be shared by the Party responsible for the action shortly before taking such action); and
(v) The planned start-up testing and operational start-up or change dates for any permanently added, removed or significantly altered generation units.

4.1.2 Transfer of SCADA Data

The Parties shall transfer data as set forth below, consistent with NERC requirements for the transfer of data by Control Areas and Reliability Coordinators.

(a) The Parties shall transfer requested SCADA Data via ICCP or ISN.
(b) Each Party shall accommodate, as soon as practical, the other Party's requests for additional existing ICCP/ISN bulk transmission data points, after the request has been submitted.
(c) Each Party shall respond, as soon as practical, to the other Party's requests for additional, unavailable ICCP/ISN bulk transmission data points, but in any event no more than two (2) weeks after the request has been submitted, with an expected availability target date for the requested data.
(d) The Parties shall comply with all governing confidentiality agreements executed by the Parties relating to ICCP/ISN data.
(e) All ICCP data transferred between the Parties shall be transferred via ISN (NERCNet), unless another transfer platform is otherwise agreed upon.

4.1.3 EMS Models

As contemplated in Section 3.3, the Parties shall exchange data between the EMS models once a year in the common information model ("CIM") format adopted by the NERC Data Exchange Working Group, or an otherwise agreed upon format. Updates shall be provided as soon as practicable after new data becomes available. This yearly transfer shall include the ISN data definition files, identification of individual bus loads, seasonal equipment ratings and one-line drawings that will be used to expedite the model conversion process. The periodic updates shall represent the incremental changes that have occurred to the EMS model since the last update.

4.1.4 Operations Planning Data

Upon the written request of a Party, the other Party shall provide the information specified in Sections 4.1.4.1 through 4.1.4.11 inclusive, or any components thereof. Each request shall specify the information sought and, for each category of information, the frequency with which it shall be provided. A Party receiving a request under this Section shall provide the information promptly to the extent the information is available to the Party.

4.1.4.1 – Flowgates:

(i) Flowgate definitions including seasonal TTC, TRM, CBM, and appropriate multipliers;
(ii) Flowgates to be added to OASIS Request Evaluation processes on demand, if needed immediately for reliability;
(iii) List of Coordinated and Reciprocal Coordinated Flowgates between other Reciprocal Entities;
(iv) List of Flowgates to recognize when processing transmission service;
(v) Operating Guides; and
(vi) Firm and non-firm AFC for all Flowgates.

4.1.4.2 - Transmission Service Reservations:

(i) Daily list of all transmission service requests, hourly increment of new requests and status changes on existing requests;
(ii) List of reservations to include and to exclude.

4.1.4.3 - AFC Data:

Each Party currently meets and shall continue to meet a minimum periodicity for calculating and posting AFCs as specified in this Section. The minimum periodicity depends on the service being offered. Each Party shall provide the following AFC data:

(i) Hourly for the first seven (7) days posted at a minimum, once per hour;
(ii) Daily for days eight (8) through thirty-one (31) posted at a minimum, once per day; and
(iii) Monthly for months two (2) through thirty-six (36) posted at a minimum, once per month.

4.1.4.4 - Load Forecast:

(i) Hourly for the first seven (7) days, daily for days eight (8) through thirty-one (31), and monthly for months two (2) through thirty-six (36) submitted once a day;
(ii) Identify whether the load forecast is for Control Area or sub-Control Area (by company within the Control Area) forecast;
(iii) Indicate whether this includes transmission system losses, and if it does, indicate what the percent losses are;
(iv) Identify non-conforming loads, as defined by NERC;
(v) Indicate how municipal entities', cooperatives' and other entities' loads are treated. Indicate whether they are included in the forecast. If so, indicate the total load or net load after removing other entity generation; and
(vi) Data listed in Section 5.1.6. to the extent not provided thereunder.

4.1.4.5 - Generator Data:

(i) Unit owner, bus location in model;
(ii) Seasonal ratings, PMIN, PMAX, QMIN, QMAX;
(iii) Station auxiliaries to extent gross generation has been reported;
(iv) Regulated bus, target voltage and actual voltage;
(v) Planned maintenance; and
(vi) Real-time output (MW & Mvar) with net generation after being reduced for station auxiliaries preferred.

4.1.4.6 – Jointly-Owned Units:

(i) Deemed ownership shares;
(ii) Treatment as pseudo tie or dynamic/static schedules;
(iii) Rules for sharing output between joint owners of those units that affect the operating seam between the Parties; and
(iv) Transmission arrangements between joint owners.

4.1.4.7 - Intermittent Generation:

(i) Accredited capacity;
(ii) Planned maintenance;
(iii) Whether aggregated generation or generation by piece of equipment;
(iv) Whether all output is tagged; and
(v) Estimated EFOR.

4.1.4.8 - Control Area Net Interchange from Reservations and Tags:

(i) Any pre-OATT agreements that do not appear in OASIS; and
(ii) If tags and reservations can no longer be used to develop Control Area or zone net interchange, merit order block loading information shall be required for all generators in the Control Area/zone.

4.1.4.9 - Dynamic Transfers:

(i) List of dynamic transfers;
(ii) Identification of each dynamic transfer as a dynamic schedule or pseudo-tie, as defined by NERC; and
(iii) The information listed in Section 5.1.11.

4.1.4.10 - Controllable Devices:

(i) List of controllable devices that may include: phase shifters, DC lines, and back-to-back AC/DC converters; and
(ii) Operating practices of the controllable devices.

4.1.4.11 - Generation and Transmission Outages:

(i) Generation Outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 5.1.1;
(ii) Transmission Outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 5.1.3; and
(iii) Prompt notification of all forced Outages of both generation and transmission resources.

4.2 Cost of Data and Information Transfer.

Each Party shall bear its own cost of providing information to the other Party pursuant to Section 4.1 for those costs related to reliability coordination. Manitoba Hydro shall have no obligation under this Agreement for costs incurred solely for MISO Market operations.

ARTICLE V
ATC/AFC CALCULATIONS

5.1 ATC/AFC Protocols.

As of the Effective Date, the Parties shall use the NERC System Data Exchange ("SDX") System, or such other mutually agreed system, to transfer the status of generators, Outages of all interconnections and other critical transmission facilities, and peak load forecasts. This system has the capability to house daily data for the next seven (7) days, weekly data for the next month, and monthly data for the next year. The Parties shall comply with the specific criteria for satisfying the requirements of this Article V as specified in the TTC/ATC/AFC Protocol which is Attachment A to this Agreement.

5.1.1 Generation Outage Schedules

Each Party shall provide the other Party with projected status of generation availability over the next twelve (12) months. If information is available, Parties may provide more than twelve (12) months of information regarding the projected status of generation availability. The Parties shall update this data no less than once daily for the full posting horizon and more often as required by system conditions. The data shall include complete generation maintenance schedules and the most current generator availability data, such that each Party is aware of the "return date" of each generator subject to a scheduled or forced Outage.

5.1.2 Generation Merit Order

As necessary to permit a Party to develop a reasonably accurate dispatch for any modeled condition, each Party shall provide the other Party with either a typical generation merit order, the generation participation factors of all generating units or typical planned generation schedules on an affected Control Area basis. Such information shall be updated as required by changes in the status of the applicable generating units or operating conditions; however, such data need not be provided more often than prior to each peak load season.

5.1.3 Transmission Outage Schedules

Each Party shall provide the other Party with the projected status of transmission Outage schedules over the next twelve (12) months or more if available. This data shall be updated no less than once daily for the full posting horizon and more often as required by system conditions. The data shall include current, accurate and complete transmission facility maintenance schedules, including the "Outage date" and "return date" of a transmission facility from a scheduled or forced Outage.

5.1.4 Transmission Interchange Schedules

Each Party shall make available to the other Party its interchange schedules, as required to permit accurate calculation of TTC and ATC/AFC values. Due to the high volume of this data, the Parties shall either post this data to an FTP site for download or shall request NERC to modify the IDC to allow for selected interrogation by the Parties or provide the data on another mutually agreed to system.

5.1.5 Transmission Service Requests

(a) Each Party shall make available, to the other Party, on an FTP site or other mutually agreed to system, all transmission service request information available for integration into each Party's ATC/AFC calculation process. The Parties shall provide transmission service request information from the Parties' respective OASIS Nodes.

(b) Each Party shall develop practices for modeling each Party's transmission service requests, including external third party requests. Each Party shall provide the other Party with the procedures developed and implemented to model intra-Party requests under the Parties' respective Tariffs.

(c) Transactions shall not be included in ATC/AFC determinations if the impacts from the transmission service request are already accounted in a base case model or some other component of the ATC/AFC calculation. Each Party shall create and maintain a list, on an FTP site or other mutually agreed to system, of transmission service requests on their OASIS Node that are not included in their own ATC/AFC determination process so that the transmission service request is excluded in the other Party's analysis.

5.1.6 Load Data

The Parties shall transfer peak load data for each period (*e.g.*, daily, weekly, and monthly). Since, by definition, peak load values may only apply to one (1) hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the first seven (7) day horizon, the Parties shall either supply hourly load forecasts or they shall supply daily peak load forecasts with a load profile.

5.1.7 Calculated Firm and Non-firm Available Flowgate Capability

To determine if a transmission service reservation (or interchange schedule) will impact Flowgates to an extent greater than the (firm or non-firm) AFC and to assure that each Party respects the other Party's Flowgates, the Parties shall transfer Firm and Non-firm AFC for all Flowgates.

Each Party shall accept or reject transmission service requests based upon projected loadings on their own Flowgates as well as the loadings on the other Party's Flowgates so as not to exceed the posted AFC.

5.1.8 Flowgate Rating

The Parties shall transfer Flowgate Ratings (seasonal, normal and emergency) as well as all limiting conditions (thermal, voltage, or stability) with such frequency as determined by NERC. The Parties shall update this information in a timely manner as required by changes on the transmission system.

5.1.9 Identification of Flowgates

As determined in accordance with the Protocols (Attachments A and B), Flowgates that have a response factor equal to or greater than the distribution factor cut-off shall be included in the evaluating Party's model to the extent inclusion is practical. The Parties shall use the response factor cut-off that the owning/operating Party uses for its Flowgate in its AFC determination efforts.

5.1.10 Configuration/Facility Changes (for power system model updates)

(a) The Parties shall ensure that all significant system changes are incorporated in their respective TTC/ATC/AFC calculation models. This data transfer shall occur no less often than prior to each peak load season.

(b) In addition, the Parties agree to transfer TTC/ATC/AFC calculation models of their transmission systems.

5.1.11 Dynamic Schedule Flows.

Each Party agrees to provide the other Party with the actual amount and future projection of dynamic schedule flows commencing no later than sixty (60) days from the Effective Date of this Agreement. All dynamic schedule flows and tags will be submitted in accordance with NERC policy and procedures.

ARTICLE VI
COORDINATION OF FLOWGATES

6.1 Scope of Coordination.

In order to coordinate congestion management proactively, each Party agrees to respect the other Party's determinations of ATC/AFC and curtailment priorities for real-time operations applicable to the Party's Coordinated Flowgates (CFs). Additionally, each Party agrees to respect the allocations of all Reciprocal Entities defined by the reciprocal allocation process set forth in the Congestion Management Process currently in effect between MISO and Manitoba Hydro, Attachment B to this Agreement.

6.2 Application of Attachment B

Except as set forth in the following sections and subsections, MISO and Manitoba Hydro agree to implement the Congestion Management Process identified in Attachment B to this Agreement. Such Congestion Management Process includes, but is not limited to, a separate calculation for MISO and Manitoba Hydro for all processes as defined in Attachment B, including determination of Coordinated Flowgates, impacts, limits and allocations of each Party on Coordinated Flowgates and RCFs, and maintaining ASTFC amounts that are used to approve firm transmission service and are available for allocation sharing and transferring.

6.2.1 Responsibility for Calculations

MISO shall be responsible for all calculations, on Manitoba Hydro’s behalf and acting as Manitoba Hydro’s managing entity, required pursuant to section 6 of the Congestion Management Process in Attachment B of this Agreement.

6.2.2 Management of Flows on Coordinated Flowgates and Reciprocal Coordinated Flowgates

The MISO shall utilize its Unit Dispatch System (UDS), Security-Constrained Unit Commitment (SCUC), and Security Constrained Economic Dispatch (SCED) in effect at the time to manage the portion of the flows on Coordinated Flowgates and RCFs attributable to the MISO. Manitoba Hydro shall utilize the NERC TLR process to manage the portion of the flows on Coordinated Flowgates and RCFs attributable to Manitoba Hydro, except as otherwise provided herein.

6.3 Treatment of MHEX Flowgate.

The Parties agree to the designation of the Manitoba Hydro-owned portion of the MHEX Flowgate as a RCF, pursuant to Section 3.2 of Attachment B to this Agreement, notwithstanding that the Flowgate may not pass the sensitivity studies for Coordinated Flowgates.

Allocation on MHEX Flowgates will be calculated based on ownership and not based on historical impacts. Manitoba Hydro will own 100% of the MHEX Flowgates allocation as the Canadian owner of the Manitoba-United States Interface. The Minnkota Power Cooperative, Inc. and MISO allocations of the MHEX Flowgate (U.S. portion) shall be defined by the Manitoba-U.S. Interface Transmission Capacity Rights Agreement entered into between Northern States Power Company, Minnesota Power, Minnkota Power Cooperative, Inc., and Otter Tail Power Company on July 17, 2015.

6.4 Treatment of External Asynchronous Resource (EAR)

The Parties agree that MISO will include bi-directional EAR as a Dispatchable Dynamic Schedule in its calculation of Market Flow on MISO's Coordinated Flowgates and RCFs and to be used for market-to-market settlement on M2M Flowgates with PJM Interconnection, LLC and Southwest Power Pool, Inc. The EAR tag will be ignored by the IDC when determining tag impacts subject to curtailment during TLR.

6.5 Flowgate Definition

The Parties agree to work towards developing a common methodology to be used by all Reciprocal Entities for determining the transmission elements that constitute a Flowgate within the meaning of Attachments A and B.

6.6 Process and Timing for Reciprocal Coordinated Flowgates.

The Parties shall comply with the process and timing for exchanging ATC/AFC calculations and Firm Flow calculations/allocations with respect to all RCFs as set forth in Attachment A and Attachment B to this Agreement.

6.7 Real-Time Operations Process.

The Parties' capabilities (as set forth in Section 5.4 of Attachment B to this Agreement) and real time actions shall be governed by and in accordance with the Coordination Process for RCFs, set forth in the Protocols.

ARTICLE VII
RESOURCE PLANNING PROVISIONS

7.1 Planning Reserve Margin and Qualifications for Planning Resources

7.1.1. Manitoba Hydro shall establish a planning reserve margin consistent with applicable NERC standards and probabilistic assessment methods, the analytical study methods described in Module E-1 of the MISO Open Access Transmission and Energy Markets Tariff and internal corporate policy. Manitoba Hydro shall establish qualifications for planning resources which are consistent with the registration and qualification procedures in the MISO Open Access Transmission and Energy Markets Tariff and the relevant MISO Business Practices Manuals. The Manitoba Hydro planning reserve margin and qualifications for planning resources will be included in Manitoba Hydro's power resource plan which will be submitted to MISO in a manner and on a schedule that is mutually agreeable to the Parties.

7.1.2 MISO acknowledges that the processes and criteria utilized by Manitoba Hydro for the establishment of their planning reserve margin and for qualifying resources as planning resources, as described in subsection 7.1.1, are comparable to the processes and criteria contained in the Module E-1 of the MISO Open Access Transmission and Energy Markets Tariff and the relevant MISO Business Practices Manuals.

7.2 Procedures for Energy Emergencies

7.2.1 The Parties agree that, in the event of a simultaneous Energy Emergency, the Parties shall follow the joint emergency procedures developed by the Parties in accordance with Section 8.7 of the Agreement, as may be amended by the Parties from time to time, prior to implementing firm end-use load shedding. The joint emergency procedures shall, at a minimum, meet the requirements of any applicable NERC reliability standards, as well as specify the following for each of the Parties:

(a) the conditions required to constitute a simultaneous Energy Emergency;

(b) the calculation and methodology that will be utilized to determine the amount of load curtailment (in MW) including the identification of the applicable capacity resources; and

(c) the procedures for tagging capacity resources that are required to flow during firm end use load shedding.

7.3 Data

7.3.1 In addition to the transfer of information and data obligations of Manitoba Hydro pursuant to this Agreement, Manitoba Hydro agrees to provide the following information to the MISO in connection with the resource planning activities of the Parties:

7.3.1.1 End-use load estimates as such are contained in the Manitoba Hydro power resource plan submitted in a manner and on a schedule that is mutually agreeable to the Parties.

7.3.1.2 Generation Verification Test Capacity (GVTC) and NERC Generation Availability Data System (GADS) data for all resources used to serve firm requirements of Manitoba Hydro submitted in a manner and on a schedule that is mutually agreeable to the Parties.

7.3.1.3 Fixed resource plans as such are contained in the Manitoba Hydro power resource plan submitted in a manner and on a schedule that is mutually agreeable to the Parties.

7.3.2 MISO acknowledges that the submittal of end-use load estimate information by Manitoba Hydro, as described in subsection 7.3.1.1 is submitted in a comparable manner to that of other Load entities in Module E-1 of the MISO Open Access Transmission and Energy Markets Tariff.

7.3.3 MISO acknowledges that the submittal of fixed resource plans by Manitoba Hydro, as described in subsection 7.3.1.3 is a comparable process to that used by Market Participants for Fixed Resource Adequacy Plans in Module E-1 of the MISO Open Access Transmission and Energy Markets Tariff.

ARTICLE VIII
ADDITIONAL COORDINATION PROVISIONS

8.1 Application of Congestion Management Process.

The Parties have agreed to certain Protocols under this Agreement to ensure system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. These Protocols include the Congestion Management Process and the TTC/ATC/AFC Protocols. The Parties expect that these systems and the Protocols applicable to these systems will change and revisions of this Agreement and the Protocols will be required from time to time.

8.2 Operating Objectives, Changes.

The operating objectives of this Agreement can be fulfilled efficiently and economically only if the Parties, from time to time, review and as appropriate revise the requirements stated herein in response to such changes, including deleting, adding, or revising the Protocols (Attachments A and B) and the Business Practices. The Parties agree to cooperate and negotiate in good faith to amend this Agreement as necessary to achieve its objectives.

8.3 Voltage Control and Reactive Power Coordination.

Each Party acknowledges that voltage control and reactive power coordination are essential to maintain reliability. Therefore, the Parties shall establish procedures ("Voltage and Reactive Power Coordination Procedures") by which they shall conduct such coordination. Such Procedures shall be set forth in the MH-MISO Business Practices.

8.4 Outage Coordination.

The Parties shall perform regional transmission and generation outage coordination in order to identify proposed transmission and generation maintenance that would create unacceptable reliability-related system conditions and will work with the facility owners to provide remedial steps to be taken in advance of such proposed maintenance. Either Party may request that the other Party reschedule an Outage to maintain reliability. Outage coordination under this Agreement shall be administered in accordance with the procedures set forth in the MH-MISO Business Practices.

8.5 Compensation for Rescheduled Outages

In the event that a Party agrees to reschedule an Outage at the request of the other Party, the rescheduling Party shall be compensated by the other Party for the reasonable and explicit additional costs incurred as a result of the rescheduling. These costs shall include labour, equipment rental costs, direct and verifiable replacement energy costs, but shall not include lost opportunity costs. Such compensation shall be conditional on FERC approval of comparable compensation provisions related to compensation to MISO facility owners for Outages.

For greater certainty of interpretation, neither Party shall be compensated for rescheduling an Outage at the direction of MISO acting as a Reliability Coordinator.

8.6 Coordinated Planning Process.

The objectives of the planning coordination process are to make certain that appropriate and adequate reviews of transmission planning functions are performed between the MISO and Manitoba Hydro on a collaborative basis to ensure comparability, efficiency and timeliness. Coordination under this Agreement shall be administered in accordance with the procedures set forth in the MH-MISO Business Practices.

8.7 Joint Operation of Emergency Procedures.

A set of emergency operating principles are essential due to the highly interdependent nature of facilities under different authorities. The Parties are committed to reliable operation of the transmission system under normal conditions, and shall work closely together during emergency situations that place the stability of the transmission system in jeopardy. The emergency operating principles are set forth in the MH-MISO Business Practices.

8.8 Transmission Capacity for Reserve Sharing.

Each Party shall make transmission capacity available within the transmission system under its responsibility for generation reserve sharing. The Parties shall reserve the required TRM, or its equivalent, for those transmission owners that are part of a generation reserve sharing pool if the Party belongs to the same generation reserve sharing pool as said transmission owners. The

Party responsible for making transmission capacity available for the reserve sharing obligation shall bear the costs of any redispatch required to make the transmission capacity available.

ARTICLE IX
EFFECTIVE DATE

9.1 The MISO shall file this Agreement with FERC. In that filing, the MISO shall request FERC to approve an Effective Date of the date upon which the Agreement is filed. Notwithstanding the foregoing, the Effective Date of this Agreement shall be the date specified by FERC.

ARTICLE X
COOPERATION AND DISPUTE RESOLUTION PROCEDURES

10.1 Data Review Rights.

Each Party shall keep complete and accurate records relating to the performance of its obligations, as well as any calculations necessary in the performance of such obligations, under this Agreement and shall maintain such data as may be necessary for the purpose of ascertaining that its performance, or calculations in support of such performance, conforms to the standards set forth in this Agreement and any Protocols referred to herein, including, but not limited to, data supporting the calculation of TTC, TRM, ATC/AFC, and RCF allocations. Each Party shall maintain these complete and accurate records for a period of one year from the end of the fiscal year during which the obligations were performed. Within that one year period, either Party may request in writing copies of the records of the other Party to the extent reasonably necessary to verify that the performance, or calculations in support of such performance, conforms to this Agreement and any Protocols referred to herein. The costs of the data review, including costs related to retrieving, compiling, reproducing and analyzing any data requested pursuant to this provision, shall be borne by the Party making the request.

10.2 Condition Precedent to Arbitration.

Prior to initiation of arbitration or legal proceedings, any controversy, claim or dispute regarding an alleged breach of this Agreement shall be first submitted to a designated senior representative of each Party with authority to settle the dispute for resolution on an informal basis. If the controversy, claim or dispute is not resolved within 30 calendar days after referral to the designated representatives, either Party with the consent of the other Party, may proceed to arbitration, in accordance with Sections 10.3 through 10.10 hereof.

10.3 Initiation

Arbitration proceedings must be initiated within 120 calendar days of the date the controversy, claim or dispute was first submitted to the designated officers and shall be initiated by written notice to the other Party setting forth the point or points in dispute. Unless otherwise agreed to in writing by the Parties, failure to initiate arbitration within such 120 day period shall be deemed a waiver of the right to arbitrate that controversy, claim or dispute. Provided however, that any such waiver shall not preclude a Party from initiating arbitration proceedings in respect of a similar claim, controversy or dispute based on facts which arise subsequent to the date the controversy, claim or dispute was first submitted to designated representatives.

10.4 Arbitration Proceedings

For greater clarity and certainty, arbitration shall not be available to anyone who is not a Party to this Agreement, and an agreement by the Parties to arbitrate shall not preclude a Party from seeking contribution, indemnification or damages from the other Party in proceedings instituted by third parties in courts of competent jurisdiction. Unless otherwise agreed or specified herein, the arbitration shall be conducted in the English language in Winnipeg, Manitoba before three arbitrators and shall be conducted in accordance with *The Arbitration Act* of Manitoba (Chapter A120 of the Consolidated Statutes of Manitoba s amended and then in effect). Each Party shall choose one arbitrator and the arbitrators so chosen shall, within twenty (20) days, select a third arbitrator to chair the arbitration panel. All arbitrators shall be competent by virtue of education and experience in the particular matter subject to arbitration. The arbitrators shall require witnesses to testify under oath administered by a duly qualified person. The arbitrators shall have jurisdiction and authority only to interpret, apply or determine compliance with the provisions of this Agreement insofar as shall be necessary to determine the particular matter subject to arbitration. The arbitrators shall not have jurisdiction or authority to add to, detract from, or alter the provisions of this Agreement or any applicable law or rule of civil procedure. The arbitrators shall have the power to order specific performance under any and all provisions of this Agreement and no Party can avoid specific performance based on an argument that the other Party has an adequate remedy at law.

10.5 Jurisdiction

The arbitrators may rule on their own jurisdiction, including any objections with respect to the existence or validity of an agreement to arbitrate. If a Party disputes the authority or jurisdiction of the arbitrators, the Party shall notify the other Party as soon as the matter alleged to be beyond the authority or jurisdiction of the arbitrators is raised during the arbitration proceedings. The arbitrators may rule on the issue as to whether or not they have the authority or jurisdiction in dispute, either as a preliminary question or in an award on the merits.

10.6 Discovery

Each Party shall have the rights of discovery in accordance with the applicable rules of *The Arbitration Act* of Manitoba. All issues subject to discovery shall be determined by order of the arbitrators upon motion made to them by either Party. When a Party is asked to reveal material which the Party considers to be proprietary information or trade secrets, the Party shall bring the matter to the attention of the arbitrators who shall make such protective orders as are reasonable and necessary or as otherwise provided by law.

10.7 Continuation of Performance

Pending the final decision of the arbitrators, the Parties agree to diligently proceed with the performance of all obligations.

10.8 Costs

All fees, costs and expenses of the arbitrators and the Parties incurred in connection with the arbitration shall be allocated between the Parties by the arbitrators. The nature of the dispute and the outcome of the arbitration shall be factors considered by the arbitrators when allocating such fees, costs and expenses. Fees, costs and expenses to be allocated shall include the Party's own employees, expert consultants and legal fees, the costs of exhibits and other incidental costs.

10.9 Arbitration Decisions

The decision of the arbitrators shall be final and binding upon the Parties except that the decision may be appealed solely on a question of law alone or set aside in accordance with the provisions of *The Arbitration Act* of Manitoba.

10.10 Correction and Interpretation of Award; Additional Award

Within 30 calendar days after receipt of an award, a Party, with notice to the other Party, may request the arbitrators to correct in the award any errors in computation, any clerical or typographical errors or any errors of a similar nature, or may request the arbitrators to give an interpretation of a specific point or a part of the request. The interpretation shall form part of the award. The arbitrators may correct any error as herein-before referred to on their own initiative within 30 calendar days after an award. In addition, within 30 calendar days after receipt of an award, a Party with notice to the other party, may request the arbitrators to make an additional award as to claims presented in the arbitration but omitted from the award. If the arbitrators consider the request to be justified, they shall make an additional award within 60 calendar days after receipt of the request. The arbitrators may extend, if necessary, the period of time within which it shall make a correction, interpretation or an additional award.

ARTICLE XI
RELATIONSHIP OF THE PARTIES

11.1 Relationship Between this Agreement and Energy Markets.

The Parties agree that execution of this Agreement will further enable the Parties to address many of the specific tasks that are required for the administration of a functioning market by one or both of the Parties. Specifically, Articles III through VII of this Agreement detail certain assignments that may pertain to the reliability and administration of adjacent energy markets. To ensure efficient handling of tasks hereunder the Parties agree to cooperate in good faith to develop further MH-MISO Business Practices that may be required to facilitate each Party's efforts to administer its respective markets.

ARTICLE XII
ACCOUNTING AND ALLOCATION OF COSTS OF SEAMS OPERATIONS

12.1 Revenue Distribution.

This Agreement does not modify any prior agreement between the MISO and Transmission Owners regarding revenue distribution.

12.2 Billing and Invoicing Procedures.

Manitoba Hydro shall render invoices to the MISO for reimbursement amounts due under this Agreement in accordance with the MH-MISO Business Practices and payment shall be due in accordance with said Business Practices. All payments shall be made in immediately available funds payable to Manitoba Hydro by wire transfer pursuant to instructions set out by the Parties from time to time. Interest on any amounts not paid when due shall be calculated in accordance with the Agreed Interest Rate.

12.3 Access to Information by the Parties.

Each Party grants the other Party, acting through its officers, employees and agents, such access to the books and records of the other as is necessary to audit and to verify the accuracy of charges under this Agreement. Such access shall be at the location of the Party whose books and records are being reviewed pursuant to this Agreement and shall occur during regular business hours.

ARTICLE XIII
RETAINED RIGHTS OF PARTIES

13.1 Parties Entitled to Act Separately.

This Agreement does not create or establish, and shall not be construed to create or establish, any partnership or joint venture between the Parties. This Agreement establishes terms and conditions solely of a contractual relationship, between two entities, to facilitate the achievement of the joint objectives described in the Agreement. The contractual relationship established hereunder implies no duties or obligations between the Parties except as specified expressly herein. All obligations hereunder shall be performed in a manner that complies with each Party's internal requirements; provided, however, this sentence shall not limit payment obligations under Article XII or indemnity obligations under Section 14.3.1 or Section 14.3.2, respectively.

13.2 Agreement to Cooperate.

Manitoba Hydro agrees to cooperate in good faith in the filing by MISO of this Agreement and any Section 205 filings with FERC that may be required to implement the terms of this Agreement.

ARTICLE XIV
ADDITIONAL PROVISIONS

14.1 Confidentiality.

14.1.1 Meaning.

The term "Confidential Information" shall mean: (a) all information, whether furnished before or after the Effective Date, whether oral, written or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "confidential" or "proprietary"; (b) all reports, summaries, compilations, analyses, notes or other information of a Party hereto which are based on, contain or reflect any information that has been marked "confidential" or "proprietary"; and (c) any information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC's Standards of Conduct set forth in 18 CFR § 37 *et seq.* and the Parties' Standards of Conduct on file with the FERC; (d) any information which has been designated Critical Energy Infrastructure Information by an entity in accordance with FERC Regulations 18 C.F.R. §141.300, §388.112, and §388.113; and (e) information about proposed or existing critical infrastructure that: (i) relates to the production, generation, transportation, transmission, or distribution of energy; (ii) could be useful to a person in planning an attack on critical infrastructure; and (iii) does not simply give the location of the critical infrastructure.

14.1.2 Protection.

During the course of the Parties' performance under this Agreement, a Party may receive or become exposed to Confidential Information. Except as set forth herein, the Parties agree to keep in confidence and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing Party. In addition, each Party shall ensure that its employees, its subcontractors and its subcontractors' employees and agents to whom Confidential Information is exposed agree to be bound by the terms and conditions contained herein. Each Party shall be liable for any breach of this Section by its employees, its subcontractors and its subcontractors' employees and agents. Furthermore, each Party shall ensure that its members to whom Confidential Information is exposed agree to be bound by the terms and conditions herein and may not use such Confidential Information for any purpose other than the purposes of this Agreement. This obligation of confidentiality shall not extend to information that, at no fault of the recipient Party, is or was either: (1) in the public domain or generally available or known to the public; or (2) disclosed to a recipient by a third party who had a legal right to do so; or (3) independently developed by a Party or known to such Party prior to its disclosure hereunder; or (4) which is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel. In the latter event, the recipient hereby agrees to provide the issuing Party with prompt Notice of such request or requirement in order to enable the issuing Party to: (a) seek an appropriate protective order or other remedy, (b) consult with the recipient with respect to taking steps to resist or narrow the scope of such request or legal process, or (c) waive compliance, in whole or in part, with the terms of this Section. In the event that such protective order or other remedy is not obtained, or that the issuing Party waives compliance with the provisions hereof, the recipient hereby agrees to furnish only that portion of the Confidential Information which the recipient's counsel advises is legally required and to exercise best efforts to obtain assurance that confidential treatment will be accorded to such Confidential Information.

14.2 Protection of Intellectual Property

(a) All Intellectual Property: (i) owned by a Party on or before the Effective Date of this Agreement; or (ii) developed by a Party after the Effective Date of this Agreement, shall remain the sole property of such Party, and no right, title or interest to such Intellectual Property shall be granted to any other Party.

(b) Except as expressly set forth in a subsequent binding agreement, no Party shall use, convey or disclose the Intellectual Property of another Party without the express written consent of such other Party and nothing herein shall be construed to be a license or other transfer by a Party of any Intellectual Property or interests therein to another Party.

14.3 Indemnity

14.3.1 Indemnity of MISO

Manitoba Hydro shall defend, indemnify and hold the MISO harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against the MISO, only to the extent such Losses arise directly from:

(a) Gross negligence, recklessness, or willful misconduct of Manitoba Hydro or any of Manitoba Hydro's agents or employees, in the performance of this Agreement, except to the extent the Losses arise from: (i) gross negligence, recklessness, willful misconduct or breach of contract or law by the MISO or any of the MISO's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon the MISO or the MISO's agents or employees;

(b) Any claim that Manitoba Hydro violated any copyright, patent, trademark, license, or other Intellectual Property right of a third party in the performance of this Agreement;

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 14.2; and

(d) Any claim that Manitoba Hydro caused physical personal injury due to gross negligence, recklessness, or willful conduct of its agents while on the premises of the MISO.

14.3.2 Indemnity of Manitoba Hydro

The MISO shall defend, indemnify and hold Manitoba Hydro harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against Manitoba Hydro, only to the extent such Losses arise directly from:

(a) Gross negligence or recklessness, or willful misconduct of MISO or any of MISO's agents or employees, in the performance of the Agreement, except to the extent the Losses arise from: (i) gross negligence, recklessness, willful misconduct or breach of contract or law by Manitoba Hydro or any of Manitoba Hydro's agents or employees; or (ii) as a consequence of strict liability imposed as a matter of law upon Manitoba Hydro or Manitoba Hydro's agents or employees;

(b) Any claim that the MISO violated any copyright, patent, trademark, license, or other Intellectual Property right of a third party in the performance of this Agreement;

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 14.2; and

(d) Any claim that the MISO caused physical personal injury due to gross negligence, recklessness, or willful conduct of its agents while on the premises of Manitoba Hydro.

14.3.3 Notification and Settlement of Claims

Each Party shall Promptly notify the other Party of claims, demands or actions that may result in a claim for indemnity. Failure to notify shall not relieve a Party from liability unless and then only to the extent that such failure results in the forfeiture by such Party of a substantial right or defense. No settlement of any claim which may result in a claim for indemnity shall be made by either Party without the prior written consent of the other Party, which consent shall not be unreasonably withheld. A Party shall not be liable under this Agreement in respect of any settlement of a claim unless said Party has consented in writing to such settlement.

14.3.4 Damages Limitation

14.3.4.1 Except for amounts agreed to be paid under Articles VII and IX of this Agreement, no Party shall be liable to the other Party, directly or indirectly, for any damages or losses of any kind sustained due to any failure to perform or negligent performance of this Agreement, unless such failure to perform or negligent performance was malicious or reckless.

14.3.4.2 Except for amounts agreed to be paid by one Party to the other under this Agreement, any liability of a Party to the other Party hereunder shall be limited to direct damages as qualified by the following sentence. No lost profits, damages to compensate for lost goodwill, consequential damages, or punitive damages shall be sought or awarded.

14.4 Effective Date and Termination Provision.

The term of this Agreement commences upon the Effective Date and shall continue so as to coincide with the term of the Coordination Agreement By and Between MISO and Manitoba Hydro (or its successor Agreement), unless terminated earlier by: (1) one Party notifying the other of its intent to terminate, which Notice must be provided no later than twelve (12) months prior to the termination date; (2) upon the mutual agreement by the Parties to terminate the Agreement; (3) FERC or other regulatory order terminating the Agreement; or (4) in accordance with Section 14.13.2.

14.5 Survival Provisions.

The applicable provisions of this Agreement shall continue in effect after termination of this Agreement to provide for final billings and adjustments, dispute resolution, confidentiality and the determination and enforcement of liability and indemnification arising from acts or events that occurred while this Agreement was in effect.

14.6 No Third-Party Beneficiaries or Obligors.

This Agreement is intended solely for the benefit of the Parties and their respective successors and permitted assigns and is not intended to and shall not confer any rights, obligations or benefits on, any third party (other than the Parties' successors and permitted assigns). Provided, that nothing in this Section 13.6 shall affect the rights and obligations of third-party Reciprocal Entities, as defined in Attachment B to this Agreement.

14.7 Successors and Assigns.

This Agreement shall inure to the benefit of and be binding upon the Parties and their respective successors and assigns permitted herein, but shall not be assigned except: (a) with the written consent of the non-assigning Party, which consent may be withheld in such Party's absolute discretion; and (b) in the case of a merger, consolidation, sale, or spin-off of substantially all of a Party's assets. In the case of any merger, consolidation, reorganization, sale, or spin-off by a Party, the Party shall assure that the successor or purchaser adopts this Agreement and the other Party shall be deemed to have consented to such adoption.

14.8 *Force Majeure.*

No Party shall be in breach of this Agreement to the extent and during the period such Party's performance is prevented or delayed due to any cause or causes beyond such Party's control, the effects of which could not have reasonably been foreseen, prevented or overcome, remedied or mitigated in whole or in part by the non-performing Party through the exercise of reasonable care ("force majeure event"). Force majeure events may include, but are not limited to: any act of God, labor disturbance, act of the public enemy, act of terrorism, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or curtailment, order, regulation or restriction imposed by governmental, military or lawfully established civilian authorities. Upon the occurrence of an event considered by a Party to constitute a *force majeure* event, such Party shall use reasonable efforts to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event, provided that this Section shall require no Party to settle any strike or labor dispute. A Party claiming a *force majeure* event shall notify the other Party in writing immediately and in no event later than forty-eight (48) hours after the occurrence of the *force majeure* event. The foregoing notwithstanding, the occurrence of a cause under this Section shall not excuse a Party from making any payment otherwise required under this Agreement.

14.9 Governing Law and Jurisdiction.

This Agreement shall be interpreted, construed and governed by Canadian Law without giving effect to its conflict of law principles. The Parties agree to the exclusive jurisdiction of the Manitoba Court of Queen's Bench and the Manitoba Court of Appeal for the resolution of disputes arising from this Agreement which are not resolved by arbitration pursuant to Article IX hereof and for the appeal or application to set aside an arbitral decision issued pursuant to Article X, or any other judicial remedies.

14.10 Notice.

Whether expressly so stated or not, all Notices, demands, requests and other communications required or permitted by or provided for in this Agreement shall be given in writing to a Party at the address set forth below, or at such other address as a Party shall designate for itself in writing in accordance with this Section, and shall be delivered by hand or reputable overnight courier:

Manitoba Hydro
820 Taylor Avenue
Winnipeg, Manitoba R3C 2P4
Canada
Attention: Vice-President – Transmission

Midcontinent Independent System Operator, Inc.
720 City Center Drive
Carmel, Indiana 46032
Attention: General Counsel

14.11 Execution of Counterparts.

This Agreement may be executed in any number of counterparts, each of which shall be an original but all of which together will constitute one instrument, binding upon the Parties hereto, notwithstanding that both Parties may not have executed the same counterpart.

14.12 Condition Precedent

Performance of the Parties' obligations under this Agreement is subject to the statutory and regulatory requirements of each Party's jurisdiction, including the receipt and continued effectiveness of any statutory or regulatory approvals required by a Party with respect to the implementation of this Agreement.

14.13 Amendment and Renegotiations.

14.13.1 Amendment.

Except as may otherwise be provided herein, neither this Agreement nor any of the terms hereof, may be amended unless such amendment is made in writing, signed by the Parties, and filed and accepted by FERC.

14.13.2 Renegotiations.

If any provision of this Agreement, or the application thereof to any person, entity or circumstance, is held by a court or regulatory authority of competent jurisdiction to be invalid, void, or unenforceable, or if a modification or condition to this Agreement is imposed by a regulatory authority exercising jurisdiction over this Agreement, the Parties shall endeavor in good faith to negotiate such amendment or amendments to this Agreement as will restore the relative benefits and obligations of the signatories under this Agreement immediately prior to such holding, modification or condition. If either Party finds such holding, modification or condition unacceptable and the Parties are unable to renegotiate a mutually acceptable resolution, either Party may unilaterally terminate this Agreement upon thirty (30) days Notice to the other Party.

14.14 Representations and Warranties.

Each Party warrants and represents to the other Party that it and its representatives executing this Agreement possess the necessary corporate and legal authority, right and power to enter into and agree to this Agreement and to perform each and every obligation imposed herein.

14.15 Remedies.

The rights and remedies of the Parties in this Agreement (unless specifically stated otherwise) are not intended to be exclusive but rather are cumulative and in addition to any other right or remedy otherwise available to the Parties at law or in equity. Either Party may exercise one or more of its rights and remedies from time to time, independently, or in combination, without prejudice to any other right or remedy available to it at law or in equity.

IN WITNESS WHEREOF, the Parties have caused this Agreement to be executed by their duly authorized representatives.

MANITOBA HYDRO

By: *_/s/ S. Mailey_*

Name _Shane Mailey_

Title: _VP Transmission_

Date: _March 20, 2017_

MIDCONTINENT INDEPENDENT SYSTEM OPERATOR, INC.

By: *_/s/ Jennifer Curran_*

Name: _Jennifer Curran_

Title: _Vice President, System Planning & Seams Coordination_

Date: _3/21/2017_

ATTACHMENT A

TO

MANITOBA HYDRO-MISO SEAMS OPERATING AGREEMENT

TTC / ATC / AFC

And

Transmission Service Request Evaluation

Coordination

Protocol

1. Purpose

The calculation of TTC and AFC pertains to a forecast of transmission capacity that may be available for use by transmission customers. Use of transmission capacity under one tariff can impact the loadings, voltages and stability of electric transmission systems that must be coordinated with use of transmission capacity under the tariff of a neighboring entity. Because of this interrelationship, neighboring entities must exchange pertinent data for each entity to determine the TTC and AFC values for its own transmission system. The collection of data related to calculation of TTC and AFC is necessary to assure reliable coordination, and also to permit all tariff administrators to determine if, due to lack of transmission capacity, it must refuse a transmission reservation in order to avoid overloading of facilities.

Coordination of transmission service request evaluation practices between tariff administrators is necessary to ensure comparable, reliable and efficient evaluations. Throughout this document the terms “ATC” and “AFC” are used synonymously with respect to flowgates, to describe remaining capability on a flowgate. The term AFC is used throughout this document to mean both AFC and ATC.

1.1 Transmission Interchange Schedules

1.1.1 Purpose

Because interchange schedules impact the short-term use of the transmission system, exchange of schedule data is necessary to determine the remaining capacity of the transmission system as well as to determine the net impact of loop flow.

1.1.2 Requirements

Manitoba Hydro and MISO will make available to each other their respective interchange schedules. Tags utilizing both firm and non-firm transmission service will be used to permit accurate calculation of AFC values and for MISO to estimate parallel path flow impacts in the administration of the MISO day-ahead and real-time energy market. Manitoba Hydro and MISO will evaluate the most economical method to provide this data. MISO will provide marginal zone information it develops for calculating and uploading to the NERC IDC distribution factors on flowgates for schedules sourcing/sinking in the MISO market and sinking/sourcing outside the MISO market and for schedules associated with grandfathered agreement carve-outs within the MISO market footprint. Such data shall include distribution factors of schedules sourcing/sinking in the MISO market and/or sufficient information regarding the marginal zones such that Manitoba Hydro can calculate the distribution factors of schedules sourcing/sinking in the MISO market.

1.2 Transmission Reservations

1.2.1 Purpose

Beyond the operating horizon, the impacts of existing transmission reservations are also necessary for the calculation of AFC for future time periods. Inasmuch as a transmission reservation is a right to use and not an obligation to use the transmission system, there is no certainty that any particular reservation will result in a corresponding interchange schedule. This is especially true considering that the Open Access Transmission Tariffs of the Parties allow firm service on a given path to be redirected on any other path. In addition, the ultimate transmission customer may not have, at a given time, purchased all transmission reservations on a particular source-to-sink path. A further complication is that the duration or firmness of the one portion of the reservation may not be the same as the remaining portion. Since the portions of a source to sink reservation may not be able to be associated prior to scheduling, double-counting in the AFC determination process is a possibility. Reservations on either the Manitoba Hydro or MISO tariffs will be incorporated into transmission models developed by Manitoba Hydro and MISO as outlined in this document to improve coordination.

1.2.2 Relationship to Coordination Agreement

The Parties acknowledge that as of the Effective Date of this Agreement, MISO is providing certain tariff administration services to Manitoba Hydro pursuant to the Coordination Agreement, such as the evaluation of short term transmission service requests under the Manitoba Hydro Open Access Transmission Tariff. Accordingly, the parties acknowledge that Manitoba Hydro's obligations under this Attachment A shall be performed by MISO on behalf of Manitoba Hydro to the extent that MISO performs the applicable services to Manitoba Hydro under the Coordination Agreement.

1.2.3 Requirements

a) Actual transmission reservation information for the Manitoba Hydro transmission tariff will reside on the Manitoba Hydro OASIS node and will be used by MISO as outlined in this document, for integration into MISO's TTC/AFC determination process and for integration into MISO's day-ahead and real-time energy market processes. In addition, Manitoba Hydro shall make available to MISO the transmission reservation data set resulting from Manitoba Hydro's importing and filtering of reservations from other OASIS nodes.

b) MISO shall use Manitoba Hydro's reservation data including both firm and non-firm reservations in its day-ahead and real-time energy market. MISO's market shall include the effects of Manitoba Hydro's firm and non-firm reservations in the calculation of parallel path impacts from Manitoba Hydro on the MISO system.

c) MISO transmission reservation information will reside on the MISO OASIS node and will be used by Manitoba Hydro as outlined in this document, for integration into Manitoba Hydro's TTC/AFC determination process. In addition, MISO shall make available to Manitoba Hydro the transmission reservation data set resulting from MISO's importing and filtering of reservations from other OASIS nodes.

d) Manitoba Hydro and MISO shall require a transmission reservation for all service sourcing in their own footprint, and sinking outside their own footprint except for certain grandfathered agreements, certain MISO Market carve-outs posted on OASIS as of the date of execution of this Agreement and certain generation reserve sharing obligations and other circumstances which would be addressed on a case-by-case basis consistent with the MH-MISO Business Practices.

e) Manitoba Hydro and MISO shall require a transmission reservation for service sourcing outside their own footprint and sinking inside their own footprint, except for certain grandfathered agreements, certain MISO Market carve-outs posted on OASIS as of the date of execution of this Agreement and certain generation reserve sharing obligations and other circumstances which would be addressed on a case-by-case basis consistent with the MH-MISO Business Practices.

f) With respect to importing reservations from other OASIS nodes, Manitoba Hydro and MISO agree to the following principles regarding the filtering of such reservations to prevent double-counting reservations and to prevent decrementing for certain partial-path reservations:

MISO Reservation Filtering Rules:

i. MISO shall include active transmission service requests on its own OASIS node (e.g., those requests that have a status of STUDY, ACCEPTED, COUNTEROFFER, REBID and CONFIRMED).

ii. If MISO can determine that the transmission service sold by another Transmission Provider will require transmission service on the MISO tariff (the request is partial path), MISO will not include the CONFIRMED status reservation from the other Transmission Provider in its data set.

iii. For transmission service between two Transmission Providers where MISO is importing reservations from both Transmission Providers, MISO shall keep the source reservation and discard the sink reservation.

iv. For transmission service between two Transmission Providers where MISO is only importing reservations from one of the Transmission Providers, MISO shall keep the reservation if the Transmission Providers are either the source or the sink.

v. If a Transmission Provider has sold a wheel (the source control area and sink control area are not connected to the Transmission Provider's Transmission System) and MISO is importing reservations from either the source control area or the sink control area, MISO shall discard the wheel reservation.

vi. If a Transmission Provider has sold a wheel and MISO is not importing reservations from either the source control area or the sink control area, MISO shall keep the wheel reservation.

Manitoba Hydro Reservation Filtering Rules:

i. Manitoba Hydro shall include active transmission service requests on its own OASIS node (e.g., those requests that have a status of STUDY, ACCEPTED, COUNTEROFFER, REBID and CONFIRMED.)

g) To provide a balanced approach to AFC calculations which recognizes operating experience, Manitoba Hydro and MISO shall jointly develop, by mutual agreement, and implement practices for modeling reservations, including external reservations, and netting practices for any allowance of counter-flows created by confirmed reservations in electrically opposite directions as outlined below. Such practices shall ensure that interface limits are not exceeded if counter-flow schedules are curtailed.

Manitoba Hydro and MISO reserve the right to modify the above netting and counterflow practices for firm and non-firm AFC postings following operational experience with such practices. Changes to the above practices shall be made with mutual agreement of Manitoba Hydro and MISO considering stakeholder review and input.

1.3 AFC Components

1.3.1 Purpose

The development of AFC components includes several factors including:

- Total Transfer Capability (or "TTC"),
- The base anticipated flow (referred to as "Base Flow") ,
- Transmission Reliability Margin (or "TRM"), and
- Capacity Benefit Margin (or "CBM").

Coordinated approaches for determining these factors with respect to Reciprocal Coordinated Flowgates ("RCFs") are desirable to ensure consistent and comparable AFC components. At a minimum, Manitoba Hydro and MISO agree to the following practices for RCFs between Manitoba Hydro and MISO and may or may not implement these practices for flowgates that are not reciprocal between Manitoba Hydro and MISO.

1.3.2 Requirements

a) With respect to TTC, Manitoba Hydro and MISO shall

i. Develop a process to review and approve TTC calculations for jointly owned flowgates,

ii. Develop a process to review and approve TTC calculations for interdependent flowgates (such as NDEX, MHEX, MWSI) where the flowgate protects both MISO and non-MISO systems and for other flowgates that significantly affect such flowgates, and

iii. Review and, if necessary, update their TTC components on flowgates at the reasonable request of the other party.

b) With respect to Base Flow,

i. MISO shall determine the forecasted market flows on RCFs based on the assumption that the MISO market may cause flows up to their firm capacity allocation on any RCF. MISO shall use in the AFC calculation the market flows based on the results of the projected market flow forecast. If the projected market flow on a flowgate is less than MISO's firm allocation, MISO shall use in the AFC calculations the market flow estimate, not the firm allocation.

ii. Manitoba Hydro shall provide MISO with designated network resource information such as planned generator dispatch based upon assumed flow conditions. Manitoba Hydro shall determine the forecasted generation-to-load flows on RCFs based on the assumption that Manitoba Hydro may cause flows up to its firm capacity allocation on any RCF. Manitoba Hydro shall use in the AFC calculation these forecasted generation-to-load flows. If the projected generation-to-load flow on a flowgate is less than Manitoba Hydro's firm allocation, Manitoba Hydro shall use in the AFC calculations the generation-to-load flow estimate, not the firm allocation.

iii. Both parties will jointly determine processes for honoring flowgate contractual rights,

iv. Both parties will regularly re-examine their generation-to-load assumptions to ensure the assumptions reflect anticipated system conditions taking into account updated generation-to-load impacts. Manitoba Hydro and MISO recognize that multiple base model scenarios may be needed to adequately determine generation-to-load impacts.

c) With respect to TRM and CBM for RCFs between Manitoba Hydro and MISO, the Parties shall apply the TRM and CBM calculation methodology of the applicable NERC reliability region where the RCF is located.

d) All RCFs between Manitoba Hydro and MISO shall include the effects of each other's respective study-status reservations on such flowgates in a commonly agreed upon and consistent manner. Based on certain rules, this would include the decrementing and holding of AFC on RCFs regardless of the tariff (MISO or Manitoba Hydro) by which the request was made. The rules to be applied in this regard include:

i. AFCs will not be decremented for study-status reservations if the other party is on the path of the request,

ii. Manitoba Hydro and MISO shall develop business practices by which shorter term firm service will be made available if flowgate capacity is insufficient to accommodate shorter term service due to the inclusion of study-status reservations and/or conditional confirmed reservations and the System Impact Studies and/or facility improvements required for such requests will not be completed during the term of the short term service being offered, and

iii. Each party will apply its own study-status decrementing policy in decrementing its flowgate AFC's for the other party's study-status reservations.

e) To better coordinate the impacts of roll-over rights on the two tariffs, Manitoba Hydro and MISO shall:

i. Institute a system of tracking reservations with roll-over rights. The requests to include in the tracking mechanism should include all Manitoba Hydro and MISO reservations as well as appropriate third party reservations.

ii. Ensure that all Manitoba Hydro and MISO flowgate AFC Postings include the effects of all confirmed reservations with roll-over rights from the rollover right tracking mechanism described above,

iii. Each Party shall independently evaluate whether rollover rights can be accommodated on partial path reservations under their respective tariffs.

1.4 Evaluation Practices

1.4.1 Purpose

Coordinated approaches in performing planning studies supporting AFC components and studies evaluating transmission service requests are desirable to ensure consistent and comparable AFC component development and transmission service evaluations.

1.4.2 Requirements

a) Manitoba Hydro and MISO shall enter into good faith negotiations to develop by mutual agreement, a method to evaluate the impacts of new network resource additions, new transmission service requests and new transmission system facilities.

b) Manitoba Hydro and MISO shall implement a comparable process with respect to on-the-path and off-the-path evaluation methodologies. The process shall have the capability to evaluate a transmission service request against only designated flowgates. The process shall be consistent with the reservation importing rules employed by the parties. The process shall result in reservations only being evaluated against the other party's flowgates when it is known that the other party is not on the contract path of the reservation and will not otherwise evaluate the request. If a flowgate has been evaluated through request evaluation on one party's tariff and the AFC for that flowgate has already been decremented and held for the partial path service, then that flowgate will not be evaluated again by Manitoba Hydro or MISO provided that the source and sink have not changed, provided that both requests have comparable distribution factors and provided that the evaluation is based on appropriate service priorities (i.e., if the source reservation is non-firm and the reservation under evaluation is firm, then the current reservation evaluation shall be based on firm ATCs for that third-party flowgate). The transmission customer shall be responsible for identifying instances in which the situation described in the previous sentence applies. Note that MISO does not include known partial path requests made on other transmission provider tariffs when decrementing MISO flowgate AFCs.

c) Both parties may use discretion with respect to including counterflow impacts when evaluating long-term firm transmission reservations. Such discretion shall be documented in the system impact study developed in regard to such service.

d) With respect to re-directing transmission service, the on-the-path/off-the-path evaluation procedure noted above is recognized with the following additional provisions. A request to re-direct existing service will be treated as a new request. The following rules shall apply:

i. If the original request was accepted by Manitoba Hydro or MISO only because the request was partial path and the other party (Manitoba Hydro or MISO) was on the original contract path or were the source/sink point for the original reservation:

  a. For any re-direct of such original service on the Manitoba Hydro or MISO system in which the other party is not on the re-directed contract path and is not the source/sink point for the re-directed reservation, the flowgates of the other party will be considered in evaluation of the re-direct service.

  b. For any re-direct of such original service on the Manitoba Hydro or MISO system in which the other party is on the re-directed contract path or is the source/sink point for the re-directed reservation, the other party's flowgates will not be considered in the evaluation of the re-directed service.

ii. If the original request was accepted by Manitoba Hydro or MISO for reasons other than the application of the on-the-path/off-the-path procedure (such reasons could include: (a) the request was accepted because there was adequate AFC on the flowgate when the request was evaluated, or (b) the request had less than the minimum acceptable impact on the flowgates to be evaluated (less than a 5% distribution factor on a PTDF flowgate or less than a 3% impact on an OTDF flowgate):

  a. For a re-direct of such original service in which the other party is not on the re-directed contract path and is not the source/sink point for the re-directed reservation, the other party's flowgates will be considered in the evaluation of the re-direct request.

    i. In such cases, if the distribution factor of the re-directed path on the flowgates is greater than the minimum acceptable distribution factor cutoff values and is less than or equal to the distribution factor of the original path on such flowgates, the service will be accepted.

    ii. If the distribution factor of the re-directed path on the flowgate is greater than the minimum acceptable distribution factor cutoff value and is greater than the distribution factor of the original path, the service will be refused if there is not adequate AFC available to provide the service or mitigation (flowgate re-dispatch or system expansion) is unavailable.

  b. For any re-direct of such original service on the Manitoba Hydro or MISO tariffs in which the other party is on the re-directed contract path or is the source/sink point for the re-directed reservation, the other party's flowgates will not be considered in the evaluation of the re-direct request.

e) By decrementing AFCs for each other's study-status requests and including each other's study-status requests in off-line system impact studies, Manitoba Hydro and MISO will honor each other's queue dates regardless of the tariff in evaluating transmission service. This specifically does not include any pre-empting of service on the other party's tariff.

1.5 Calculated Firm and Non-firm Available Flowgate Capability

1.5.1 Definitions

The firm AFC is calculated with only the appropriate firm transmission service reservations (or interchange schedules) in the model, including recognition of all roll-over transmission service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) and roll-over transmission service rights modeled.

1.5.2 Purpose

Data collection 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 and procedures are necessary to assure that each tariff respects the other tariff's Flowgates as follows.

1.5.3 Requirements

(a) Manitoba Hydro and MISO will develop firm and non-firm AFC for all Flowgates for which they are the flowgate owner or flowgate administrator.

(b) Manitoba Hydro and MISO will accept or reject transmission service requests based upon projected loadings on these Flowgates as well as on RCFs. Manitoba Hydro and MISO firm transmission service request evaluation will honor each other's firm AFC postings on all Flowgates. Manitoba Hydro and MISO non-firm transmission service request evaluations will honor each other's non-firm AFC postings on all Flowgates.

(c) For the purposes of this Agreement, "honoring" each other's AFC postings shall mean using the other Party's AFC calculation in the evaluation of transmission service requests and not accepting transmission service requests that exceed that limit.

ATTACHMENT B

TO

MANITOBA HYDRO-MISO SEAMS OPERATING AGREEMENT

Congestion Management Process

Executive Summary

This Congestion Management Process[1] document provides significant detail in the areas of Market Flow Calculation. These additional details are the result of discussions between multiple Operating Entities.

As Operating Entities expand and implement their respective markets, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional) will interact to ensure that parallel flows and impacts are recognized and controlled in a manner that consistently ensures system reliability. This proposed solution will greatly enhance current Interchange Distribution Calculator (IDC) granularity by utilizing existing real-time applications to monitor and react to Flowgates external to an Operating Entity's footprint.

In brief, the process includes the following concepts:

- *Participating Operating Entities will agree to observe limits on an extensive list of coordinated external Flowgates*
- *Like all Control Areas (CA), Market-Based Operating Entities will have Firm and non-Firm GTL flows upon those Flowgates.*
- *In real-time, Market-Based Operating Entities will calculate and monitor one-hour ahead projected and actual flows.*
- *The IDC will calculate GTL flows for Operating Entities using the State Estimator data provided by the entities.*
- *Market-Based Operating Entities will calculate the actual and the one-hour ahead projected Firm and non-Firm limits for both internal and external Coordinated Flowgates.*
- *Market-Based Operating Entities will constrain their operations to limit Firm GTL flows on the Coordinated Flowgates to no more than the calculated Firm Flow Limit established in the analysis.*
- *Market-Based Operating Entities will provide to the IDC detailed representation of their marginal units, so that the IDC can continue to effectively compute the effects of all tagged transactions regardless of the size of the market area. These tagged transactions will include transactions into the market, transactions out of the market, transactions through the market and tagged grandfathered transactions within the market.*
- *When there is a Transmission Loading Relief (TLR) 3a request or higher called on a Coordinated Flowgate, and the Market-Based Operating Entity's actual/one-hour ahead projected IDC GTL flows exceed the Firm Flow Limits, Market-Based Operating Entities will respond to their relief obligations by redispatching their systems in a manner that is consistent with how non-market entities respond to their share of IDC GTL relief obligations per the IDC congestion management report.*

[1] Capitalized terms that are not defined in this Attachment 2 shall have the meaning set forth in the body, appendices, and attachments of the *MISO-Manitoba Hydro Seams Operating Agreement*.

- *The above processes refer to the "Congestion Management" portion of the paper, which will be implemented by Market-Based Operating Entities.*
- *Additional entities may choose to enter into similar Reciprocal Coordination Agreements that describe how Available Transfer Capability (ATC)/Available Flowgate Capability(AFC), Firm Flows, and outage maintenance will be coordinated on a forward basis.*
- *The complete process will allow participating Operating Entities to address the reliability aspects of congestion management seams issues between all parties whether the seams are between market to non-market operations or market-to-market operations.*

Change Summary

Generate baseline Congestion Management Process (CMP) document based on CMP documents executed by:

- Manitoba Hydro and Midcontinent Independent System Operator, Inc. (MISO)
- Mid-Continent Area Power Pool (MAPP) and MISO
- MISO and PJM Interconnection, L.L.C. (PJM)
- MISO, PJM and Tennessee Valley Authority (TVA)
- MISO and Southwest Power Pool, Inc. (SPP)

The document also includes subsequent changes agreed upon by a majority of the Congestion Management Process Council (CMPC). For items which are specific to a limited number of agreements, the CMP members have used an approach of documenting these unique items in separate appendices rather than in the base document. The CMPC members reserve all rights with respect to the different options identified in the appendices attached hereto without any obligation to adopt or support such options. The CMPC members reserve the right to oppose any position taken by another CMPC member in a FERC filing or otherwise with respect to the choice of options listed in the appendices. Nothing contained herein shall be construed to indicate the support or agreement by the CMPC members to an option presented in the appendices

Revision 1.1 (July 25, 2016)

Generated updated baseline CMP document executed by the following entities:

- Manitoba Hydro and MISO
- Minnkota Power Cooperative, Inc. and MISO
- MISO and PJM
- PJM and TVA
    - Louisville Gas and Electric Company/Kentucky Utilities Company (LG&E/KU) and Associated Electric Cooperative, Inc. (AECI) executed separate agreements with TVA stipulating the CMP provisions executed by PJM and TVA apply to AECI and LG&E/KU as Reciprocal Entities.
- MISO and SPP
- MISO Attachment LL

Section	Revision Description
3.2	Clarified language on inclusion of Coordinated Flowgates in AFC process. Removed consideration of reverse impacts when performing Flowgate studies.
3.2.1	Revised language to better describe how the four Flowgate studies used to identify Coordinated Flowgates are performed.
3.2.6	Added a new section requiring coordination between Parties before making a Flowgate permanent that includes a Tie Line monitored element.
4.1 4.1.1	Revised language to require a Market-Based Operating Entity to consistently account for export and import tagged transactions in the identified calculations using one of the three methodologies set forth in the new Section 4.1.1. Revisions have previously been accepted by FERC in the CMP documents executed between MISO and PJM, MISO and SPP, and PJM and TVA.
6.10	Added a new section listing the requirements that must be satisfied for a Combining Party to incorporate a Non-Reciprocal Entity's load and the associated generation serving that load into the Reciprocal's Entity's Allocation calculations.
Appendix A	Added the following defined terms: Agreement, Combining Party, Non-Reciprocal Entity, Party, Third-Party, and Tie Line.
Appendix B	Revised language addressing how a Market-Based Operating Entity using the Marginal Zone methodology will determine marginal zone participation factors. Revisions have previously been accepted by FERC in the CMP documents executed between MISO and PJM, MISO and SPP, and PJM and TVA.
Appendix C	Clarified in Figure C-1 and Table C-1 the steps on inclusion of Coordinated Flowages in the AFC process.

Revision 1.2 (June 1, 2017)

Per NERC Operating Reliability Subcommittee applied updates necessary for MISO to incorporate External Asynchronous Resources into MISO Market Flows.

Section	Revision Description
3.2	Updated the number of Coordination Flowgate studies from four to five.
3.2.1	Clarified Study 4 applies internal CA/CA permutations and added a new Study 5 specific to External Asynchronous Resources.
3.2.2 3.2.5	Updated the number of Coordination Flowgate studies from four to five.
4.1	Added how the External Asynchronous Resources will be considered in Market

	Flow and the exclusion of the related tags from IDC.
6.2	Updated the number of Coordination Flowgate studies from four to five.
6.8	Specified the priority of the Market Flow will correspond to the priority of the tag.
Appendix A	Added a new definition specific to MISO, External Asynchronous Resources. Updated the number of Coordination Flowgate studies from four to five.
Appendix C	Updated the number of Coordination Flowgate studies from four to five in Table C-1.

Revision 1.3 (June 2, 2022)

Updated to reflect the PFV changes as per NAESB Standard

Table of Contents

Section 1 - Introduction

It is the intention of the Reciprocal Entities to utilize the processes within this document. It is further the intention to develop this process in a way that will allow other regional entities with similar concerns to utilize the concepts within this process to aid in the resolution of their own seams issues.

1.1 Problem Definition

1.1.1 The Nature of Energy Flows

Energy flows are distinctly different from the manner in which the energy commodity is purchased, sold, and ultimately scheduled. In the current practice of “contract path” scheduling, schedules identify a source point for generation of energy, a series of wheeling agreements being utilized to transport that energy, and a specific sink point where that energy is being consumed by a load. However, due to the electrical characteristics of the Eastern Interconnection, energy flows are more dispersed than what is described within that schedule. This disconnect becomes of concern when there is a need to take actions on contract-path schedules to effect changes on the physical system (for example, the curtailment of schedules to relieve transmission constraints).

In the Eastern Interconnection, much of this concern has been addressed through the use of the North American Electric Reliability Corporation (NERC) and/or North American Energy Standards Board (NAESB) TLR process. Through this process, Reliability Coordinators utilize the *IDC* to determine appropriate actions to provide that relief. The IDC bases its calculations on the use of transaction tags: electronic documents that specify a source and a sink, which can be used to estimate real power flows through the use of a network model. In order to change flows, the IDC is given a particular constraint and a desired change in flows. The IDC returns back all source to sink transactions that contribute to that constraint and specifies schedule changes to be made that will effect that change in flows.

In other parts of the Eastern Interconnection, however, the use of centralized economic dispatch results in a solution that does not focus on changing entire transactions (effectively redispatching through the use of imbalance energy), but rather redispatch itself. In this procedure, the party attempting to provide relief does not need to know that a balanced source to sink transaction should be adjusted; rather, they are aware of a net generation to load balance and the impacts of different generators on various constraints. Bid-based security constrained central dispatch based on Locational Marginal Pricing is a regional implementation of this practice.

Currently, these two practices are somewhat incompatible. Due to the electrical characteristics of the Interconnection and geographic scope of the regions, this incompatibility has been of limited concern. However, regional market expansion has begun to draw attention to this operational disjoint, as the expansion itself exacerbates the negative effects of the incompatibility.

1.1.2 Granularity in the IDC

The IDC uses an approximation of the Interconnection to identify impacts on a particular transmission constraint that are caused by flows between Control Areas. This approximation allows for a Reliability Coordinator to identify tagged transactions with specific sources and sinks that are contributing to the constraint. While tagged transactions may specify sources and sinks in a very specific manner, the IDC in general cannot respect this detail, and instead consolidates the impacts of several generators and loads into a homogenous representation of the impacts of a single Control Area. This is referred to as the *granularity* of the IDC. Current granularity is typically defined to the Control Area level; finer granularity is present in certain special situations as deemed necessary by NERC.

1.1.3 Reduced Data and Granularity Coarseness

As centrally dispatched energy markets expand their footprint, two related changes occur with regard to the above process. In some cases, data previously sent to the IDC is no longer sent due to the fact that it is no longer tagged. In others, transactions remain tagged, but the increased market footprint results in an increase in granularity coarseness within the IDC; that is, the apparent Control Area boundary becomes the same as the market boundary so that what had been historically 30 or more Control Areas now appears as one.

In the first change, transactions contained entirely within the market footprint are considered to be utilizing network service (even when the market spans multiple Control Areas). As such, there is no requirement for them to be tagged (or such requirement is waived by NERC), and therefore, no requirement that they be sent to the IDC. This is of concern from a reliability perspective, as the IDC will no longer have a large pool of transactions from which to provide relief, although the energy flows may remain consistent with those prior to the market expansion. In other words, flows subject to TLR curtailment prior to the market expansion are no longer available for that process.

In the second change, the expansion of the footprint itself results in a dilution of the approximation utilized by the IDC. When a market region is relatively small (or isolated), the Control Area to Control Area approximation of that region's impact on transmission constraints is acceptable; actions within the market footprint generally have a similar and consistent impact on all transmission facilities outside the footprint. However, when the market footprint expands significantly, and is co-mingled with non-market Control Areas, the ability to utilize the historic approximation of electrically representative flows fails to effectively predict energy flow. Impacts on external facilities can vary significantly depending on the dispatch of the resources within the market footprint. With regard to the IDC, this information is effectively lost within the expanded footprint, and results in an increase in the level of granularity coarseness, or a "loss of granularity."

1.1.4 Accounting for Loop Flows

The processes for accounting for loop flows caused by uses of the transmission system between Control Areas are different under a market environment. Absent a market, loop flows from Transmission Service reservations between Control Areas are identified and accounted for by importing transmission reservations from surrounding systems. Under a market environment, the market will not have explicit transmission reservations for evolving market dispatch conditions between market Control Areas. Thus, a mechanism for accounting for anticipated Market Flows on non-market systems is necessary.

1.1.5 Conclusion

The net effect of these changes is that reliability must be managed through different processes than those used before the market region's expansion. While relief can still be requested using the current process, both the ability to predict the effectiveness of a curtailment to provide that relief and the general pool of transactions available for curtailment are reduced. This CMP offers a strategy for eliminating this concern through a process that provides more information (finer granularity) to the IDC for the market area. This new congestion management process will ensure that reliability is not adversely affected as markets expand by providing information and relief opportunities previously unavailable to the IDC.

1.2 Process Scope and Limitations

1.2.1 Vision Statement

As Operating Entities become Market-Based Operating Entities, and expand their various markets, one of the primary seams issues that must be resolved is how different congestion management methodologies (market-based and traditional TLR) will interact to ensure parallel flows and impacts are recognized and controlled in a manner that consistently ensures system reliability and equitability. Reliability Coordinators can mandate emergency procedures to maintain safe operating limits, however, without coordination agreements that maintain flow limits in advance, the market would become volatile and the burden for relieving excess flow would ignore the economics of the entities which would be required to redispatch. For these entities, this process will offer a manner in which Market-Based Operating Entities can coordinate parallel flows with Operating Entities that have not yet or do not contemplate implementing markets. This process will provide more proactive management of transmission resources, more accurate information to Reliability Coordinators, and more candidates for providing relief when reliability is threatened due to transmission overload conditions.

1.2.2 Process Scope

This process has been written specifically with the goal of coordinating seams between Reciprocal Entities and their respective neighbors.

1.3 Goals and Metrics

This document focuses on a solution to meet the following goals and requirements:

1. Develop a congestion management process whereby transmission overloads can be prevented through a shared and effective reduction in Flowgate or constraint usage by Reciprocal Entities and adjoining Reliability Coordinators.
2. Agree on a predefined set of Flowgates or constraints to be considered by all Reciprocal Entities, and a process to maintain this set as necessary.
3. Determine the best way to calculate flow due to market impacts on a defined set of Flowgates.
4. Develop Reciprocal Coordination Agreements that establish how each Operating Entity will consider its own Flowgate or constraint usage as well as the usage of other Operating Entities when it determines the amount of Flowgate or constraint capacity remaining. This process will include both operating horizon determination as well as forward looking capacity allocation.
5. Develop a procedure for managing congestion when Flowgates are impacted by both tagged and untagged energy flow.
6. Develop a procedure for determining the priorities of untagged energy flows (created through parallel flows from the market).
7. Agree on steps to be taken by Operating Entities to unload a constraint on a shared basis.
8. Determine whether procedure(s) for managing congestion will differ based on where the Flowgate is located (*i.e.*, inside Reciprocal Entity A, inside Reciprocal Entity B, or outside both Reciprocal Entity A and Reciprocal Entity B).
9. Confirm that the solution will be equitable, transparent, auditable, and independent for all parties.
10. Develop methodology to preserve and accommodate grandfathered transmission rights, contract rights, and other joint-use agreements.
11. Develop methodology to address changes in Total Transfer Capability (TTC), such as future system topology changes, new Designated Network Resources (DNRs), facility uprates/derates, prior outage limitations, etc., with respect to Allocation implications.
12. Develop a methodology for releasing Allocations if other parties do not join the process or if there is ATC going unused.

1.4 Assumptions

The processes set forth in this document were based on the following assumptions:

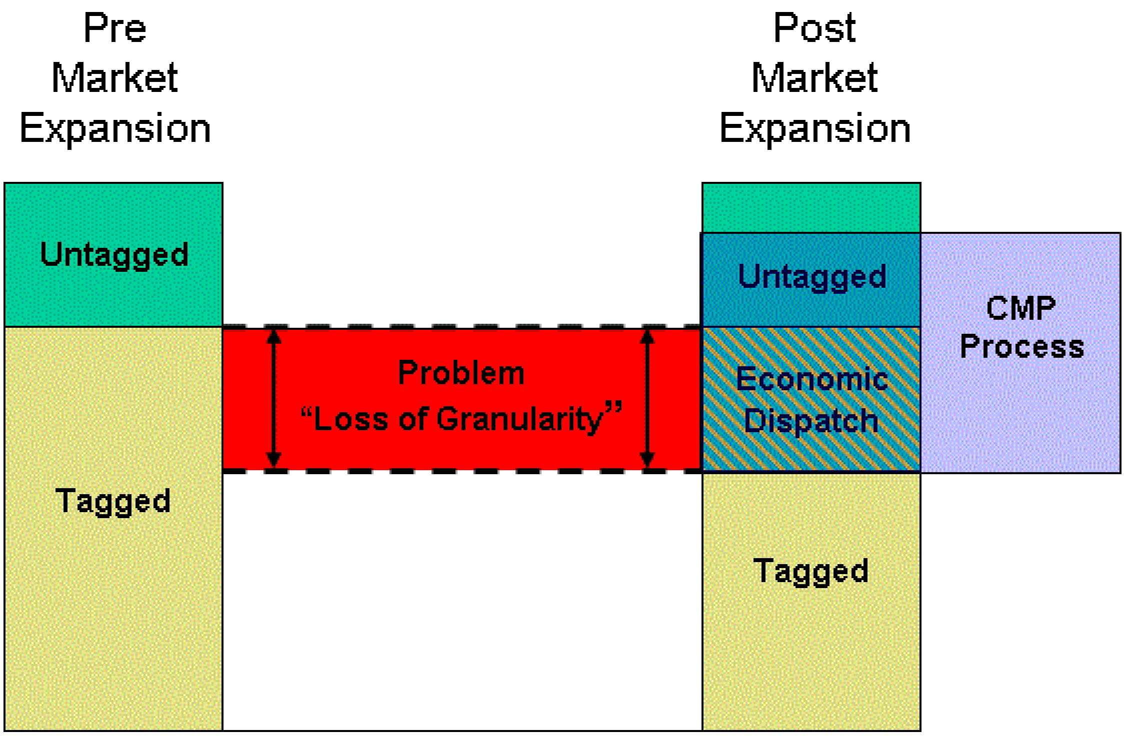
- Point-to-point schedules sinking in, sourcing from, or passing through an Operating Entity will be tagged.

- The IDC or a similar repository of schedules is needed at the Interconnection's current state and for the foreseeable future.
- The Operating Entity's Energy Management System (EMS) has the capability to monitor and respond to real-time and projected flows created by its real-time dispatch.
- The Reliability Coordinator of the area in which a Flowgate exists will be responsible for monitoring the Flowgate, determining any amount of relief needed, and entering the required relief in the IDC.
- The IDC has been modified to accept the submitted values of real-time generation, load, and other real-time data.
- The IDC calculates the impacts of the untagged dispatch (GTL) on the Flowgates for all Operating Entities using Parallel Flow Visualization (PFV).
- The IDC will determine the Firm and non-Firm GTL flow for each Market-Based Operating Entity using the Firm and non-Firm Limits calculated in this agreement.
- The IDC can calculate the total amount of MW relief required by the Operating Entity (schedule curtailments required plus the relief provided by redispatch).

Section 2 - Process Overview

2.1 Summary of Process

In order to coordinate congestion management, a bridge must be established that provides for comparable actions between Operating Entities. Without such a bridge, it is difficult, if not impossible, to ensure reliability and system coordination in an efficient and equitable manner. To effect this coordination of congestion management activities, we propose a methodology for determining both firm and non-firm flows resulting from Market-Based Operating Entity dispatch on external parties' Flowgates.


Pre
Market
Expansion
Post
Market
Expansion
Untagged
Tagged
Problem
"Loss of Granularity"
Untagged
Economic
Dispatch
Tagged
CMP
Process

are the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving load within an Operating Entity's Control Area. (Note: For the purposes of the Reciprocal Coordination process discussed later, Firm Transmission Service (7F) will be combined with the untagged firm component of Market Flows in the calculation of Historic Firm Flow. The Historic Firm Flow is described later in this document**).**

The IDC currently calculates GTL flows for each CA in the Eastern Interconnection and used to determine each Operating Entities curtailment under a TLR. The methodology defined in this document determines how to quantify these GTL flows as Firm and non-Firm for each Market-Based Operating Entity. Market Flow is a calculation similar to GTL, but is no longer used to determine relief obligations in the TLR protocol. However, Market Flow may still be used for congestion management between Market-Based Operating Entities, and thus we continue to define it in this agreement for reference.

GTL flows can be divided into Firm and Non-Firm. Firm GTL flows are considered as firm use of the transmission system for congestion management purposes and will be curtailed on a proportional basis with other firm uses during periods of firm curtailments and are equivalent to Firm Transmission Service. Non-Firm GTL flows are considered as non-firm use of the transmission system for congestion management purposes and will be curtailed on a proportional basis with other non-firm uses during periods of non-firm curtailments and are equivalent to non-firm Transmission Service. As such, Reliability Coordinators can request Market-Based Operating Entities to provide relief under TLR based on these transmission priorities.

By applying the above philosophy to the problem of coordinating congestion management, we can determine not only the impacts of a Market-Based Operating Entity's dispatch on a particular Flowgate; we can also determine the appropriate firmness of those flows. This results in the ability to coordinate both proactive and reactive congestion management between operating entities in a way that respects the current TLR process, while still allowing for the flexibility of internal congestion management based on market prices.

There are two areas that must be defined in order for this process to work effectively:

- **Coordinated Flowgate Definition.** In order to ensure that impacts of dispatch are properly recognized, a list of Flowgates must be developed around which congestion management may be effected and coordination can be established.
- **Congestion Management.** By coordinating congestion management efforts and enhancing the TLR process to recognize both untagged energy flows and data of finer granularity, we can ensure that when TLR is called, the appropriate non-firm flows are reduced before Firm Flows. This coordination will result in a reduction of TLR 5 events, as more relief will be available in TLR 3 to mitigate a constraint. This is accomplished through the calculation of flows due to economic dispatch, as well as by providing marginal unit information to aid in interchange transaction management.

The next sections of this document discuss each of these areas in detail.

Section 3 - Impacted Flowgate Determination

3.1 Flowgates

Flowgates are facilities or groups of facilities that may act as significant constraint points on the system. As such, they are typically used to analyze or monitor the effects of power flows on the bulk transmission grid. Operating Entities utilize Flowgates in various capacities to coordinate operations and manage reliability. For the purpose of this process, there are three kinds of Flowgates: AFC Flowgates, which are defined in Appendix A, Coordinated Flowgates (CFs), which are defined below, and Reciprocal Coordinated Flowgates (RCFs), which are defined in "Reciprocal Operations" Section 6. A diagram illustrating how these three categories of Flowgates are determined is included as Appendix C.

3.2 Coordinated Flowgates

An Operating Entity will conduct sensitivity studies to determine which Flowgates are significantly impacted by the flows of the Operating Entity's Control Zones (historic Control Areas that existed in the IDC). An Operating Entity identifies these Flowgates by performing the following five studies to determine which Flowgates the Operating Entity will monitor and help control. As set forth in Appendix C, a Flowgate passing any one of these studies will be considered a Coordinated Flowgate and AFCs shall be computed for these Flowgates, unless mutually agreed otherwise by the Operating Entities and any Reciprocal Entities for the Flowgate. An Operating Entity shall add a Coordinated Flowgate to its AFC process as soon as practical in accordance with the Operating Entity's processes. Nothing in this section precludes an Operating Entity or Reciprocal Entity from calculating AFCs for any Flowgates.

An Operating Entity may also specify additional Flowgates that have not passed any of the five studies to be Coordinated Flowgates where the Operating Entity expects to utilize the TLR process to manage congestion. For a list of Coordinated Flowgates between Reciprocal Entities, see each Reciprocal Entity's Open Access Same-Time Information System (OASIS) website.

Coordinated Flowgates are identified to determine which Flowgates an entity impacts significantly. This set of Flowgates may then be used in the congestion management processes and/or Reciprocal Operations defined in this document.

When performing the five Flowgate studies, a 5% threshold will be used based on the positive impact. Use of a 5% threshold in the studies may not capture all Flowgates that experience a significant impact due to operations. The Operating Entities have agreed to adopt a lower threshold at the time NERC and/or NAESB implements the use of a lower threshold in the TLR process.

3.2.1 Flowgate Studies

Study 1) – IDC GLDF

(using the IDC tool)

Upon request by an Operating Entity, a study will be performed using the IDC reflecting the topology of the system from the System Data Exchange (SDX) or any industry-accepted system with similar capabilities. The IDC can provide a list of Flowgates for any user-specified Control Area whose Generator to Load Distribution Factor (GLDF) NNL impact is 5% or greater. Using the historic Control Area representation in the IDC, if any one generator has a GLDF that is 5% or greater as determined by the IDC, this Flowgate will be considered a Coordinated Flowgate.

Study 2) – IDC PSS/E Base Case GLDF

(no transmission outages – offline study)

Upon request by an Operating Entity, the Operating Entity to which the request is made will perform a generator analysis to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. To provide better confidence that the Operating Entity has effectively captured the subset of Flowgates upon which its generators have a significant impact, the Operating Entity will perform an offline study utilizing Managing and Utilizing System Transmission (MUST) or other industry-accepted software with similar capabilities. The Operating Entity will perform off-line studies using the IDC PSS/E base case. If any generator has a GLDF that is 5% or greater as determined by this Study 2, this Flowgate will be considered a Coordinated Flowgate. Study 1 above and this Study 2 are separate studies. There is no requirement that a Flowgate must pass both studies in order to be coordinated.

Study 3) – IDC PSS/E Base Case GLDF

(transmission outage - offline study)

Upon request by an Operating Entity, the Operating Entity to which the request is made will perform a Flowgate analysis to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. The Flowgates determined using Study 2 above or Study 4 below that have a 3% to 5% distribution factor will be analyzed in this Study 3 against prior outage conditions. The Operating Entity will perform off-line studies using the IDC PSS/E base case utilizing MUST or other industry-accepted software with similar capabilities. The Operating Entity, in consultation with affected operating authorities, will perform a prior outage analysis, including both internal and external outages by applying one of the following:

1. transmission facilities operated at 100kV and above, in the CA where the Flowgate’s monitored facility(ies) is located and in CAs that are first tier to the CA where the Flowgate’s monitored facility(ies) is located; or

2. transmission facilities operated at 100kV and above within 10 buses from the monitored facility(s).

If any Flowgates with a 3% to 5% distribution factor from Study 2 or Study 4 are impacted by 5% or more from a prior outage condition (Line Outage Distribution

Factor(LODF)) from this Study 3, the Flowgate will be added to the list of Coordinated Flowgates.

Study 4) – IDC Base Case Transfer Distribution Factors

(no transmission outages – offline study)

Upon request by an Operating Entity, the Operating Entity to which the request is made will perform a Flowgate analysis to determine which Flowgates impacted by those CAs will be included in the list of Coordinated Flowgates. The Operating Entity performing this analysis will analyze internal transactions between each historic CA/CA permutation. OTDF Flowgates will be analyzed with the contingent element out of service. The Operating Entity will perform off-line studies using the IDC PSS/E base case utilizing MUST, or other industry-accepted software with similar capabilities to determine the Transfer Distribution Factors (TDFs). Flowgates that are impacted by 5% or greater by Study 4 will be considered a Coordinated Flowgate.

Study 5) – External Asynchronous Resource (EAR)

Upon request by an Operating Entity, MISO shall rerun Study 4 (no outage scenario) to determine the flowgates impacted by its EAR. Additionally, a second study will be performed using the IDC reflecting the topology of the system from the System Data Exchange (SDX) or any industry-accepted system with similar capabilities. Both studies performed under Study 5 shall utilize the following assumptions: 1) the source to sink TDF calculation of the EAR shall be evaluated in the same way IDC would evaluate the impacts of the associated tag (e.g., source and sink of the EAR); and 2) any flowgate that is determined to be impacted by the EAR by 5% or greater will be considered a Coordinated Flowgate.

3.2.2 Disputed Flowgates

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

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

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

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

3.2.3 Third Party Request Flowgate Additions

Each Party shall provide opportunities for Third Parties or other entities to propose additional Coordinated Flowgates and procedures for review of relevant non-confidential data in order to assess the merit of the proposal. The current procedure for the review and maintenance of Coordinated Flowgates is set forth in Appendix C.

3.2.4 Frequency of Coordinated Flowgate Determination

The determination of Coordinated Flowgates will be performed at the initial implementation of the CMP and then on a periodic basis, as described in Appendix C.

3.2.5 Dynamic Creation of Coordinated Flowgates

For temporary Flowgates developed "on the fly," the IDC will calculate GTL relief obligation based on GPS or TSNT method and once market entities submit the Firm Flow Limits the GTL relief obligation will be based on submitted Firm Flow Limits on the new Flowgate. Interchange transactions into, out of, or across the Market-Based Operating Entity will continue to be E-tagged and available for curtailment in TLR 3, 4, or 5. Market-Based Operating Entities will study the Flowgate in a timely manner and begin reporting Flowgate data within no more than two business days (where the Flowgate has already been designated as an AFC Flowgate). This will ensure that the Market-Based Operating Entity has the time necessary to properly study the Flowgate using the five studies detailed earlier in this document and determine the Flowgate's relationship with the Market-Based Operating Entity's dispatch. For internal Flowgates, the Market-Based Operating Entity will redispatch during a TLR 3 to manage the constraint as necessary until it begins reporting the Firm and Non-Firm Limits; during a TLR 5, the IDC will request GTL relief obligation in the same manner as today. Alternatively, for internal and external Flowgates, an Operating Entity may utilize an appropriate substitute Coordinated Flowgate that has similar Market Flows and tag impacts as the temporary Flowgate. In this case, an Operating Entity would have to realize relief through redispatch and TLR 3. An example of an appropriate substitute would be a Flowgate with a monitored element directly in series with a temporary Flowgate's monitored element and with the same contingent element.

If the Flowgate meets the necessary criteria, the Market-Based Operating Entity will begin to provide the necessary values to the IDC in the same manner as Market Flow values are provided to the IDC for all other Coordinated Flowgates. The necessary criteria for adding a Flowgate are defined in Appendix C. If in the event of a system emergency (TLR 3b or higher) and the situation requires a response faster than the process may provide, the Market-Based Operating Entities will coordinate respective actions to provide immediate relief until final review.

3.2.6 Coordination of Tie Line Flowgate Additions.

The Parties shall follow the coordination process outlined in this section for Flowgates that include a Tie Line between the Parties as a monitored element. The provisions in this section shall not apply to any temporary Flowgates.

Procedures:

1. Unless otherwise agreed to by the Parties, the managing entity for a Tie Line Flowgate is the Party that has functional control over the most limiting equipment for the Flowgate.

2. The managing entity for a Tie Line Flowgate shall calculate AFCs, post AFCs, process requests for transmission service, manage real-time congestion, and calculate Allocations for the Tie Line Flowgate.

3. Before the creation of a new Tie Line Flowgate in the IDC, the managing entity for the Tie Line Flowgate must notify the other Party no less than sixty (60) days in advance of the addition of the Tie Line Flowgate in the IDC. The new Flowgate will initially be created as a temporary Flowgate in the IDC by the managing entity. If all other requirements outlined in this Section 3.2.6 are completed during the sixty (60) days following notice, the Flowgate can be made permanent before the sixty (60) day deadline by mutual agreement of the Parties.

4. A Party that identifies a new Tie Line Flowgate through a study shall provide the study assumptions, methodology, and all other relevant data to the other Party in a timely manner.

5. AFC Calculation and Posting AFCs:
    a. The managing entity will calculate and post AFCs for Tie Line Flowgates in accordance with the managing entity's processes (i.e., the managing entity will treat the Flowgates as internal Flowgates).
    b. The managing entity will post AFC files for Tie Line Flowgates for use by other transmission providers.

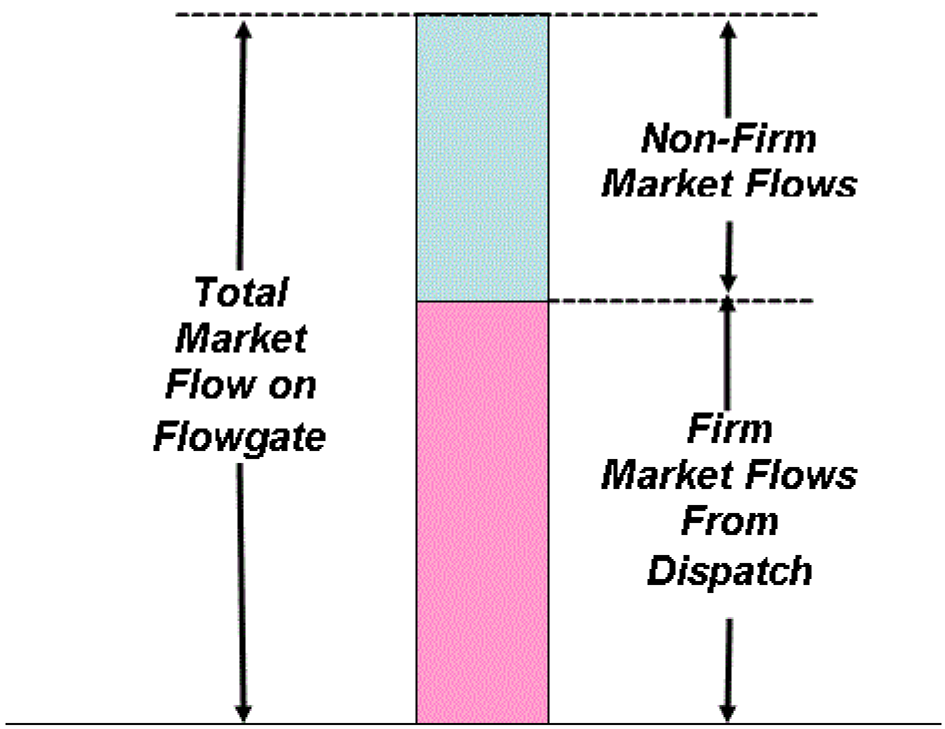
   c. The managing entity will apply AFC factors for Tie Line Flowgates (e.g., TRM, CBM, “a” and “b” multipliers, etc.) using the managing entity’s own processes.

6. Upon the completion of items 1 through 5, the managing entity may create a permanent Tie Line Flowgate.

7. The Party that is not the managing entity will replace the temporary Tie Line Flowgate with the permanent Tie Line Flowgate in its applicable operating system(s).

Section 4 - Market-Based Operating Entity Flow Calculations: Market Flow, Firm Market Flow, and Non-Firm Market Flow

Market Flows on a Coordinated Flowgate can be quantified and considered in each direction. Market Flow is then further designated into two components: Firm Market Flow, which is energy flow related to contributions from the Network and Native Load serving aspects of the dispatch, and Non-Firm Market Flow, which is energy flow related to the Market-Based Operating Entity's market operations.



Note: Market flows equal generation to load flows in market areas.

Each Market-Based Operating Entity will calculate their actual real-time and projected directional Market Flows, as well as their directional Firm and Non-Firm Market Flows, on each Coordinated Flowgate. The following sections outline how these flows will be computed.

4.1 Market Flow Determination

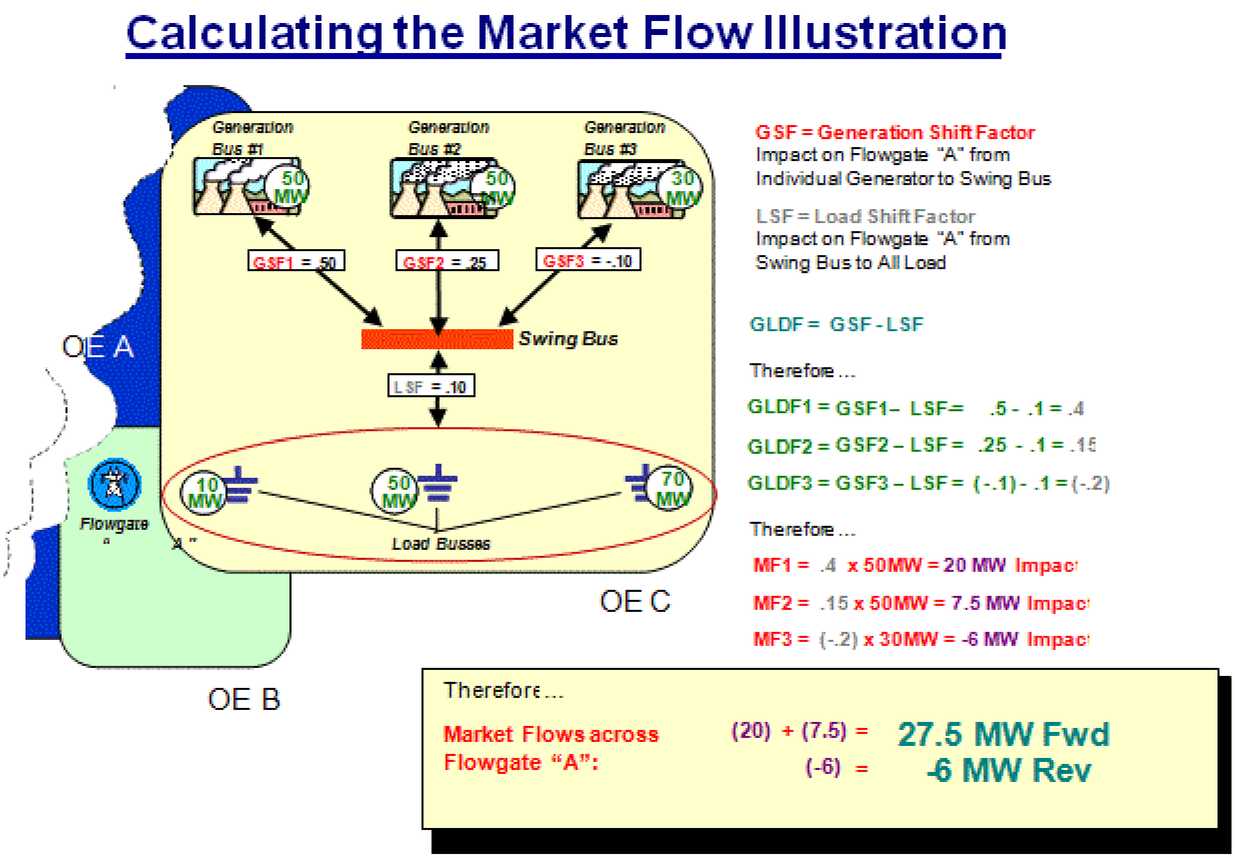
The determination of Market Flows builds on the "Per Generator" methodologies that were developed by the NERC Parallel Flow Task Force. The "Per Generator Method Without Counter Flow" was presented to and approved by both the NERC Security Coordinator Subcommittee (SCS) and the Market Interface Committee (MIC).[1]

Similar to the Per Generator Method, the Market Flow calculation method is based on Generator Shift Factors (GSFs) of a market area's assigned generation and the Load Shift Factors (LSFs) of its load on a specific Flowgate, relative to a system swing bus. The GSFs are calculated from a single bus location in the base case (*e.g.*, the terminal bus of each generator) while the LSFs are defined as a general scaling of the market area's load. The Generator to Load Distribution Factor (GLDF) is determined through superposition by subtracting the LSF from the GSF.

The determination of the Market Flow contribution of a unit to a specific Flowgate is the product of the generator's GLDF multiplied by the actual output (in megawatts) of that generator. The total Market Flow on a specific Flowgate is calculated in each direction; forward Market Flows is the sum of the positive Market Flow contributions of each generator within the market area, while reverse Market Flow is the sum of the negative Market Flow contributions of each generator within the market area.

For purposes of the Market Flow determination, the market area may be either: (1) the entire RTO footprint, as in the following illustration; or (2) a subset of the RTO region, such as a pre-integration NERC-recognized Control Area, as necessary to ensure accurate determinations and consistency with pre-integration flow determinations. Each Market-Based Operating Entity shall choose only one of these two options to calculate its Market Flows. With regard to the second option, the total Market Flow of an RTO shall be the sum of the flows from and between such market areas.

[1] "Parallel Flow Calculation Procedure Reference Document," NERC Operating Manual. 11 Feb, 2003. www.nerc.com



The Market Flow calculation differs from the Per Generator Method in the following ways:

- The contribution from all market area generators will be taken into account.
- In the Per Generator Method, only generators having a GLDF 5% or greater are included in the calculation. Additionally, generators are included only when the sum of the maximum generating capacity at a bus is greater than 20 MW. The Market Flow calculations will use all flows, in both directions, to calculate a Market Flow down to a 5% threshold and to calculate a Market Flow down to a 0% threshold. Forward flows and reverse flows are determined as discrete values.
- The contribution of all market area generators is based on the present output level of each individual unit.
- The contribution of the market area load is based on the present demand at each individual bus.

By expanding on the Per Generator Method, the Market Flow calculation evolves into a methodology very similar to the "Per Generator Method," while providing granularity on the order of the most granular method developed by the IDC Granularity Task Force. Directional flows are required for this process to ensure a Market-Based Operating Entity can effectively select the most effective generation pattern to control the flows on both internal and external constraints, but are considered as distinct directional flows to ensure comparability with existing NERC and/or NAESB TLR processes. Under this process, the use of real-time values in concert with the Market Flow calculation effectively implements one of the more accurate and detailed methods of the six IDC Granularity Options considered by the NERC IDC Granularity Task Force.

Each Market-Based Operating Entity shall choose one of the three methodologies set forth in Section 4.1.1 (Methodologies to Account for Tagged Transactions) below to account for import and export tagged transactions and shall apply it consistently for each of the following calculations:

1. the Market Flow calculation;
2. the Firm Flow Limit calculation;
3. the Firm Flow Entitlement calculation; and
4. the tagged transaction impact calculation which occurs in the IDC.

Market Flows represent the impacts of internal generation (including generators pseudo-tied into the market area and excluding generators pseudo-tied out of the market area) serving internal load (including load pseudo-tied into the market area and excluding load pseudo-tied out of the market area) and tagged grandfathered transactions within the market area. Market Flows shall not include the impacts from import tagged transaction(s) into and export tagged transaction(s) out of the market area where the impacts of the interchange transactions are accounted for by the IDC. A Market-Based Operating Entity shall utilize the IDC to calculate the impacts of import tagged transactions into and export tagged transactions out of the market area that are not captured in the Market Flow calculation. The impact of the EAR shall be included in the Market Flow calculation using the methodology selected in Section 4.1.1 (*Methodologies to Account for Tagged Transactions*); the related tags will be excluded in IDC. For an import EAR, load will be adjusted, and for an export EAR, generation will be adjusted, in accordance with the methodology selected in Section 4.1.1 (*Methodologies to Account for Tagged Transactions*).

Units assigned to serve a market area's load do not need to reside within the market area's footprint to be considered in the Market Flow calculation. Units outside of the market area that are pseudo-tied into the market to serve the market area's load will be included in the Market Flow calculation. However, units outside of the market area will not be considered when those units will have tags associated with their transfers (i.e., where pseudo-tie does not exist).

Additionally, there may be situations where the participation of a generator in the market that is not modeled as a pseudo-tie may be less than 100% (*e.g.*, a unit jointly owned in which not all of the owners are participating in the market). This situation occurs when the generator output controlled by the non-participating parties is represented as interchange with a corresponding tag(s) and not as a pseudo-tie generator internal to each party's Control Area. Except for the generator output represented by qualifying interchange transactions from jointly owned units described in the following paragraph, such situations will be addressed by including the generator output in that Market-Based Operating Entity's Market Flow calculation with the amount of generator output not participating in the market being scaled down within the Market-Based Operating Entity's region or regions in accordance with one of the following three methodologies described and defined below in Section 4.1.1: the Marginal Zone Method, POR-POD Method, or Slice-of-System Method.

When a jointly owned unit, which is also listed as a Designated Network Resource for the Historic Firm Flow calculation, participates in more than one market, and the generator output from that unit between the two markets is represented as interchange with a corresponding tag(s) that is accounted for by the IDC and not as a pseudo-tie generator internal to each market's Control Area, its modeling in the Market Flow calculation will be aligned with that in the Historic Firm Flow calculation. The amount of generator output from that unit scheduled between the two markets will be treated as a unit specific export tagged transaction in the Market Flow calculation of the Market-Based Operating Entity where the generator is located and will be treated as a load-specific import tagged transaction in the Market Flow calculation of the other Market-Based Operating Entity.

- For exports out of one market area associated with the jointly owned unit(s), the generator output of jointly owned unit will be scaled down by an amount which is the lesser of the corresponding export tagged transaction(s) and unit ownership of an owner participating in other market area.

- For imports into the other market area associated with the jointly owned external unit(s), the Control Zone load or bus load(s) will be scaled down by an amount which is the lesser of the corresponding import tagged transaction(s) and unit ownership of an owner participating in the market area.

Import tagged transactions, export tagged transactions, and grandfathered tagged transactions within the market area, must be properly accounted for in the determination of Market Flows.

Below is a summary of the calculations discussed above.

For a specified Flowgate, the Market Flow impact of a market area is given as:

Total Directional "Market Flows" = ∑ (Directional "Market Flow" contribution of each unit in the Market-Based Operating Entity's area), grouped by impact direction

where,

"Market Flow" contribution of each unit in the Market-Based Operating Entity's area =

($GLDF_{Adj}$) (Adjusted Real-Time generator output)

and,

$GLDF_{Adj}$ is the Generator to Load Distribution Factor

Where the generator shift factor (GSF_{Adj}) uses Adjusted Real-Time generator output and the load shift factor (LSF_{Adj}) uses Adjusted Real-Time bus loads.

$GLDF_{Adj} = GSF_{Adj} - LSF_{Adj}$

Adjusted Real-Time generator output is the output of an individual generator as reported by the state estimator solution that has been adjusted for exports associated with joint ownership, if any, and then further adjusted for the remaining exports utilizing the chosen methodology in Section 4.1.1.

Adjusted Real-Time bus load is the sum of all bus loads in the market as reported by the state estimator solution that have been adjusted for imports associated with joint ownership, if any, and then further adjusted for the remaining imports utilizing the chosen methodology in Section 4.1.1.

The real-time and one-hour ahead projected "Market Flows" will be calculated on-line utilizing the Market-Based Operating Entity's state estimator model and solution. This is the same solution presently used to determine real-time market prices as well as providing on-line reliability assessment and the periodicity of the Market Flow calculation will be on the same order. Inputs to the state estimator solution include the topology of the transmission system and actual analog values (*e.g.*, line flows, transformer flows, etc. . .). This information is provided to the state estimator automatically via SCADA systems such as NERC's ISN link.

Using an on-line state estimator model to calculate "Market Flows" provides a more accurate assessment than using an off-line representation for a number of reasons. The calculation incorporates a significant amount of real-time data, including:

- **Actual real-time and projected generator output.** Off-line models often assume an output level based on a nominal value (such as unit maximum capability), but there is no guarantee that the unit will be operating at that assumed level, or even on-line. Off-line models may not reflect the impact of pumped-storage units when in pumping mode; these units may be represented as a generator even when pumping. Additionally off-line models may not reflect the impact of units such as wind generators. A real-time calculation explicitly represents the actual operating modes of these units.
- **Actual real-time bus loads.** Off-line assessments may not be able to accurately account for changes in load diversity. Off-line models are often based on seasonal winter and summer peak load base cases. While representative of these peak periods, these cases may not reflect the load diversity that exists during off-peak and shoulder hours as well as off-peak and shoulder months. A real-time calculation explicitly accounts for load diversity. Off-line assessments may also reflect load reduction programs that are only in effect during peak periods.
- **Actual real-time breaker status.** Off-line assessments are often bus models, where individual circuit breakers are not represented. On-line models are typically node models where switching devices are explicitly represented. This allows for the real-time calculation to automatically account for split bus conditions and unusual topology conditions due to circuit breaker outages.

Additionally, the calculation rate of the on-line assessment is much quicker and accurate than an off-line assessment, as the on-line assessment immediately incorporates changes in system topology and generators. Facility outages are automatically incorporated into the real-time assessment.

In order to provide reliable and consistent flow calculations, entities utilizing this process as the basis for coordination must ensure that the modeling data and assumptions used in the calculation process are consistent. Reciprocal Entities will coordinate models to ensure similar computations and analysis. Reciprocal Entities will each utilize real-time ICCP and ISN data for observable areas in each of their respective state estimator models and will utilize SDX data for areas outside the observable areas to ensure their models stay synchronized with each other and the EIDSN IDC.

4.1.1 Methodologies to Account for Tagged Transactions

A Market-Based Operating Entity shall choose one of the following methodologies to account for export and import tagged transactions in the Market Flow calculation utilized for market-to-market, and shall also use the same methodology to account for export and import tagged transactions in the Firm Flow Limit and Firm Flow Entitlement calculations, as well as calculated tag impacts by the IDC:

1. Point-of-receipt (POR) / point-of-delivery (POD) Method (POR-POD Method) - Export tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for based on the POR of the transmission service reservation, as the transmission service was originally sold, that is listed on the export tagged transaction by proportionally offsetting the MW output of all units (i) in the Market-Based Operating Entity's Control Area, (ii) pre-integration NERC-recognized Control Area(s), or (iii) sub-regions within its Control Area. Import tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for based on the POD of the transmission service reservation, as the transmission service was originally sold, that is listed on the export tagged transaction by proportionally offsetting the MW load of all load buses (i) in the Market-Based Operating Entity's Control Area, (ii) pre-integration NERC-recognized Control Area(s), or (iii) sub-regions within the Control Area; or
2. Marginal Zone Method – Export tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for by adjusting the MW output of the units in the Market-Based Operating Entity's Control Area, regions, or subregions within its Control Area by the total MW amount of all the Market-Based Operating Entity's export tagged transactions excluding tagged transactions associated with jointly owned units participating in more than one market using: (1) marginal zone participation factors, as defined and calculated in Appendix B (*Determination of Marginal Zone Participation Factors*); and (2) the anticipated availability of a generator to participate in the interchange of the marginal zone. Import tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for by adjusting the MW load of the load buses in the Market-Based Operating Entity's Control Area,

regions or subregions within the Control Area, by the total MW amount of all the Market-Based Operating Entity's import tagged transactions excluding tagged transactions associated with jointly owned units participating in more than one market using marginal zone participation factors, as defined and calculated in Appendix B (*Determination of Marginal Zone Participation Factors*); or

3. Slice of System Method – Export tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted for by proportionately adjusting the MW output of each of the units in the Market-Based Operating Entity's Control Area by the total MW amount of all the Market-Based Operating Entity's export tagged transactions excluding tagged transactions associated with jointly owned units participating in more than one market. Import tagged transactions, excluding tagged transactions associated with jointly owned units participating in more than one market shall be accounted by proportionately adjusting the MW load of each of the load buses in the Market-Based Operating Entity's Control Area by the total MW amount of all the Market-Based Operating Entity's import tagged transactions excluding tagged transactions associated with jointly owned units participating in more than one market.

Each Market-Based Operating Entity shall post and maintain a document on its public website that describes calculations and assumptions used in those calculations regarding the chosen methodology and its application to the treatment of import and export transactions to the calculation of Market Flows, Firm Flow Limits, and Firm Flow Entitlements, and tag impacts calculated by the IDC.

4.2 Firm Flow Determination

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

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

1. Utilize a reference base case to determine the Generation Shift Factors for all generators in the current Control Areas' respective footprints to a specific swing bus with respect to a specific Flowgate.
2. Utilize the same base case to determine the Load Shift Factors for the Control Area's load to a specific swing bus with respect to that Flowgate.
3. Utilize superposition to calculate the Generation to Load Distribution Factors (GLDF) for the generators with respect to that Flowgate.

4. Multiply the expected output used to serve native load from each generator by the appropriate GLDF to determine that generator's flow on the Flowgate.
5. Sum these individual contributions by direction to create the directional Firm Flow impact on the Flowgate.

4.3 Determining the Firm Flow Limit

Given the Firm Flow determinations described in the previous section, Market-Based Operating Entities can assume them to be their Firm Flow Limits. These limits define the maximum value of the GTL flows that can be considered as firm in each direction on a particular Flowgate in the IDC, and the maximum value of the Market Flows that can be considered firm on a particular flowgate for market-to-market. Prior to real-time, a calculation will be done based on updated hourly forecasted loads and topology. The results should be an hourly forecast of directional Firm Flows.

4.4 Firm Flow Limit Calculation Rules

The Firm Flow Limits for both 0% GTL flows and 5% GTL flows will be calculated for each Market-Based Operating Entity based on certain criteria and rules. The calculation will include the effects of firm network service in both forward and reverse directions. The process will be similar to that of the IDC but will include one set of impacts down to 0% and another set down to 5%. The down to 0% impacts will be used to determine Firm Flow Limits on 0% GTL flows. The down to 5% impacts will be used to determine Firm Flow Limits on 5% GTL flows. The following points form the basis for the calculation:

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

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

3. Forward Firm Flow Limits for 0% GTL flows will consider impacts in the additive direction down to 0%, and reverse Firm Flow Limits for 0% GTL flows will consider impacts in the counter flow direction down to 0%. Forward Firm Flow Limits for 5% GTL flows will be determined by subtracting impacts between 0% and 5% in the additive direction from the Forward Firm Flow Limit for 0% GTL flows. Reverse Firm Flow Limits for 5% GTL flows will be determined by subtracting the impacts between 0% and 5% in the counter-flow direction from the reverse Firm Flow Limit for 0% GTL flows. Flowgate Firm Flow Limits using a 5% threshold are reported to the IDC for it to assign the Firm and non-Firm GTL flows used in TLR curtailments for each Market-Based Operating Entity. Flowgate Firm Flow Limits using a 0% threshold are reported to the IDC for information purposes.

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

5. If a generator or a portion of a generator is used to make off-system sales that have an OASIS reservation, that generator or portion of a generator should be excluded from the generation-to-load calculation.

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

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

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

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

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

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

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

Section 5 - Market-Based Operating Entity Congestion Management

Once there has been an establishment of the Firm Flow Limit that is possible given Firm Market Flow calculation, that data will be used in the operating environment in a manner that relates to real-time energy flows.

5.1 Calculating Market Flows

On a periodic basis, the Market-Based Operating Entity will calculate directional Market Flows for all market-to-market Coordinated Flowgates. These flows will represent the actual flows in each direction at the time of the calculation.

5.2 Quantify and Provide Data for Firm Flow Limits

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

- Firm Flow Limits for all Coordinated Flowgates in each direction.
- Non-Firm Flow Limits for all Coordinated Flowgates in each direction.

In real-time, any GTL flow in excess of the Firm Flow Limit will be reported as Non-Firm GTL flow (Priority 6-NN) (note that under reciprocal operations, some of this Non-Firm GTL flow may be quantified as Priority 2-NH).

These limits will be provided for both current hour and next hour, and is used in order to communicate to Reliability Coordinators the maximum amount of flows to be considered firm and non-firm on the various Coordinated Flowgates in each direction. When the Firm Flow Limit forecast is calculated to be greater than the GTL flow for current hour or next hour, all GTL flow is firm.

Additionally, as frequently as once an hour, but no less frequently than once every three months, the Market-Based Operating Entity will submit to the Reliability Coordinator sets of data describing the marginal units and associated participation factors for generation within the market footprint. The level of detail of the data may vary, as different Operating Entities will have different unique situations to address. However, this data will at a minimum be supplied for imports to and exports from the market area, and will contain as much information as is determined to be necessary to ensure system reliability. This data will be used by the Reliability Coordinators to determine the impacts of schedule curtailment requests when they result in a shift in the dispatch within the market area.

5.3 Day-Ahead Operations Process

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

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

5.4 Real-time Operations Process - Operating Entity Capabilities

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

The Operating Entities submit various system measurements (load, generator outputs, control device status, etc.) from their state estimators and Unit Dispatch Systems (UDS) to the SDX in real-time. These measurements are used by the IDC to calculate both the actual and projected hour ahead flows (*i.e.*, total GTL and tagged impact flows) on the Coordinated Flowgates. The IDC's calculations of system flows will utilize each Operating Entity's actual unit output, updated at least every 15 minutes on an established schedule.

5.5 Market-Based Operating Entity Real-time Actions

The Market-Based Operating Entity will upload the real-time and one-hour-ahead projected Firm Flow Limits (7-FN) and Non-Firm Flow Limits (6-NN) on these Flowgates to the IDC every 15 minutes, as requested by the IDCWG and OATI (note that under reciprocal operations, some of this 6-NN may be quantified as Priority 2-NH). Firm Flow Limits will be calculated, down to five percent and down to zero percent, and uploaded to the IDC. When the real-time actual flow exceeds the Flowgate limit <u>and</u> the Reliability Coordinator, who has responsibility for that Flowgate, has declared a TLR 3a or higher, the IDC will determine tag curtailments and GTL relief obligations using a tag impact and GTL impact of 5% or greater. The Market-Based Operating Entity will respond to the GTL relief obligation by redispatching their system. Note the Market-Based Operating Entity may provide relief through either: (1) a reduction of flows on the Flowgate in the direction required, or (2) an increase of reverse flows on the Flowgate.

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

The Reliability Coordinator calling the TLR will be able to see the relief provided on the Flowgate in both their EMS and in the IDC, as the IDC GTL calculation will reflect the redispatch of the Operating Entities with relief obligations through their real-time measurements submissions.

Section 6 -Reciprocal Operations

Reciprocal Coordination Agreements can be executed on a market-to-market basis, a market-to-non-market basis, and a non-market-to-non-market basis. While the congestion management portions of this document are intended to apply specifically to Market-Based Operating Entities, the agreement to allocate Flowgate capability is not dependent on an entity operating a centralized energy market. Rather, it simply requires that a set of Flowgates be defined upon which coordination shall occur and an agreement to perform such coordination.

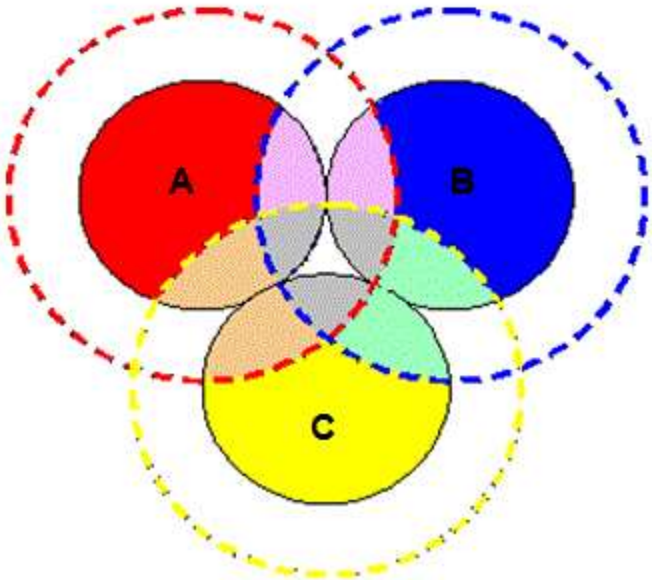
6.1 Reciprocal Coordinated Flowgates

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

6.2 The Relationship Between Coordinated Flowgates and Reciprocal Coordinated Flowgates

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

- It will meet the criteria for Coordinated Flowgate status for both the Reciprocal Entities,
- It will be under the functional control of one of the two Reciprocal Entities, and
- Both Reciprocal Entities have executed Reciprocal Coordination Agreements either with each other or with a Third Party Reciprocal Entity.



As shown in the illustration above, Operating Entity A, Operating Entity B and Operating Entity C each have their own set of Coordinated Flowgates (represented by the blue, yellow and red dotted-line circles). Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A's, Operating Entity B's or Operating Entity C's service territory (the gray area), they will be considered Reciprocal Coordinated Flowgates between all three entities. Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A's or Operating Entity B's service territory (the purple area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity B and Operating Entity A only. Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity B's or Operating Entity C's service territory (the green area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity B and Operating Entity C only. Where those sets of Coordinated Flowgates overlap AND they are in either Operating Entity A's or Operating Entity C's service territory (the orange area), they will be considered Reciprocal Coordinated Flowgates between Operating Entity A and Operating Entity C only.

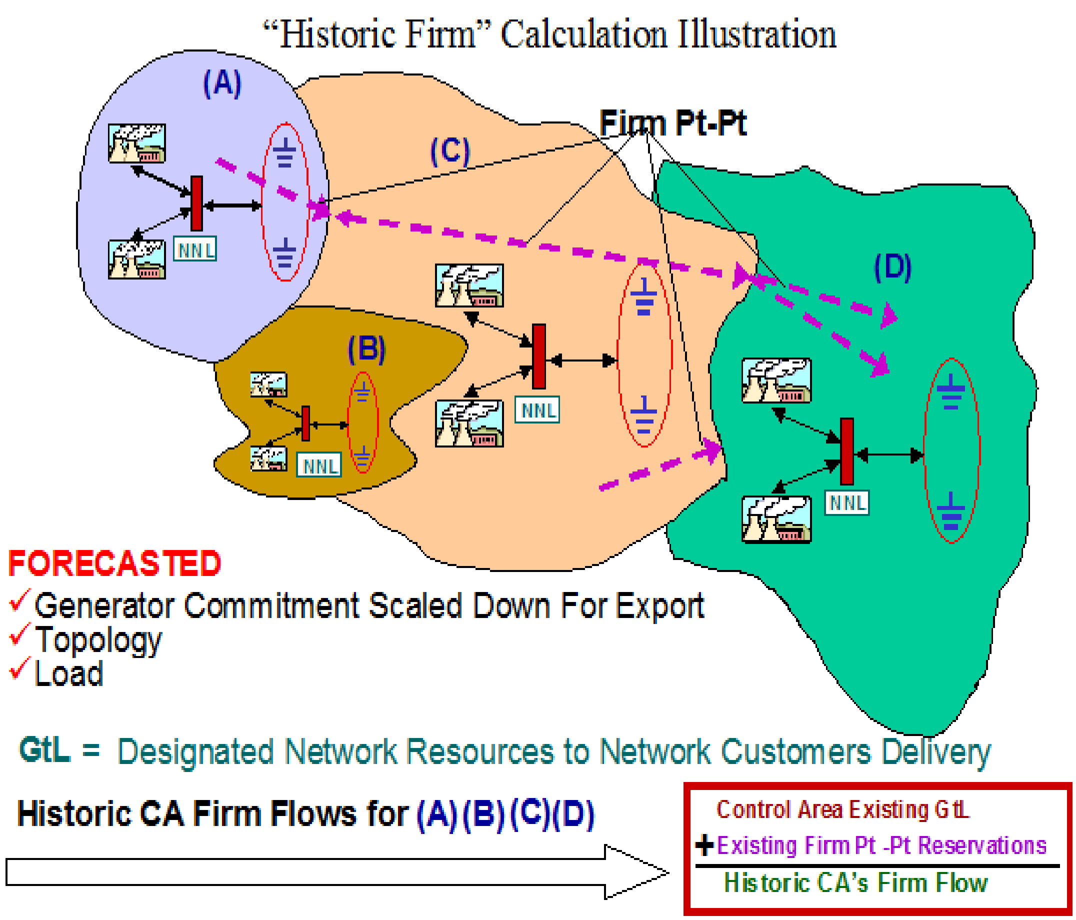
To the extent that entities other than Market-Based Operating Entities may enter into a Reciprocal Coordination Agreements, they may offer to coordinate on Flowgates that are Coordinated Flowgates (*i.e.*, have passed one of the five tests defined within this document or otherwise been deemed to be a Coordinated Flowgate).

6.3 Coordination Process for Reciprocal Flowgates

The following process and timing will be used for coordinating the ATC/AFC calculations and Firm Flow Limit calculations/Allocations between Reciprocal Entities. Further, the process quantifies and limits Priority 6 – NN service on the Reciprocal Coordinated Flowgates, as well as determines priority 2-NH service. All Reciprocal Entities' Firm Flow Limits will be calculated on the same basis.

6.4 Calculating Historic Firm Flows

As a starting point for identifying Allocations, an understanding must be developed of what Firm Flows would be in the historic Control Area structure. In other words, there must be a quantification of the Firm Flows that would have occurred if all Control Areas maintained their current configuration and continued to: (1) serve their native load with their Designated Network Resources, and (2) import and export energy at historical levels based upon Firm Transmission Service reservations as of the Freeze Date, which is currently set as April 1, 2004. This flow is referred to as Historic Firm Flow.



Reciprocal Entities will utilize the IDC Base Case model, or a mutually agreed upon alternative model as the reference base case for these calculations.

6.5 Recalculation of Initial Historic Firm Flow Values and Ratios

The Firm Transmission Service and Designated Network Resource to customer load defined by the Historic Firm Flow calculation will be updated in the recalculation of Historic Firm Flow utilizing any new Designated Network Resources, updated customer loads, and new transmission facilities. The original historic Control Areas will be retained for the recalculation of Historic Firm Flow. New Designated Network Resources will be included in the recalculation to the extent these new Designated Network Resources have been arranged for the exclusive use of load within the historic Control Areas and to the extent the total impact of all Designated Network Resources does not exceed the historic Control Area impact of Designated Network Resources as of a “Freeze Date” (defined as April 1, 2004). Any changes to Designated Network Resources and/or the transmission system that increase transmission capability will be assessed in accordance with the Reciprocal Entities AFC Coordination procedures prior to the increasing of Historic Firm Flow related to those systems.

The initial Historic Firm Flow calculated values and resulting Allocation ratios will be recalculated as seasonal cases are produced. This recalculation will utilize the same Firm Transmission Service reservations that were used in the initial Historic Firm Flow calculation. The same Firm Transmission Service reservations are used so that Market-Based Operating Entities that have their Firm Transmission Service internalized, grant fewer internal Firm Transmission Service reservations, or have their original Firm Transmission Service reservations end, because of their market operations, will retain at least the same level of Firm Transmission Service as in the initial Historic Firm Flow calculation. Therefore, the Firm Transmission Service component of the Historic Firm Flow will be frozen on the “Freeze Date” at the initially calculated level for both market and non-market entities.

Any new Control Areas that are added to the Firm Flow calculation process for any Reciprocal Entity, or another Operating Entity, will use Firm Transmission Service reservations from the initial Historic Firm Flow calculation date to establish their Firm Transmission Service component of the Historic Firm Flow.

As the recalculation for Historic Firm Flow is made for each time period, the higher of allocation value will be retained between the initial Historic Firm Flow calculation and the recalculation (See “Forward Coordination Process” Section 6.6, step 8.f). To the extent an Operating Entity has made commitments based on the higher of Allocation value, a recalculation does not reduce previously calculated Allocations.

6.6 Forward Coordination Processes

1. For each Reciprocal Coordinated Flowgate, a managing entity and an owning entity will be defined. The manager will be responsible for all calculations regarding that Flowgate; the owner will define the set of Firm Transmission Service reservations to be utilized when determining Firm Transmission Service impacts on that Flowgate.

2. Managing entities will calculate both Historic Firm Gen-to-Load Flow impacts and historic Firm Transmission Service impacts for all entities. These impacts will be used to define the Historic Ratio and the Allocation of transmission capability.
3. The managing entity will utilize the current IDC Base Case (or other mutually agreeable base case) to determine impacts. The case should be updated with the most current set of outage data for the time period being calculated.
4. Managing entities will calculate Allocations on the following schedule:

Allocation Run Type	Allocation Process Start	Range Allocated	Allocation Process Complete
April Seasonal Firm	Every April 1 at 8:00 EST	Twelve monthly values from October 1 of the current year through September 30 of the next year	April 1 at 12:00 EST
October Seasonal Firm	Every October 1 at 8:00 EST	Twelve monthly values from April 1 of next year through March 31 of the following year	October 1 at 12:00 EST
Monthly Firm	Every month on the second day of the month at 8:00 EST	Six monthly values for the next six successive months	2nd of the month at 12:00 EST
Weekly Firm	Every Monday at 8:00 EST	Seven daily values for the next Monday through Sunday	Monday at 12:00 EST
Two-Day Ahead Firm	Every Day at 17:00 EST	One daily value for the day after tomorrow	Current Day at 18:00 EST
Day Ahead Non-Firm	Every Day at 8:00 EST	Twenty-four hourly values for the next 24-hour period (Next Day HE1-HE24 EST)	Current Day at 9:00 EST

5. Historic Ratios are defined during the seasonal runs the first time an impact is calculated. For example, the 2004 April seasonal firm run would define the Historic Ratio for April 2005 – September 2005 (October through March would have been calculated during the 2003 October seasonal firm run). The Historic Ratio is based on the total impacts of the Reciprocal Entity on the Flowgate (Historic Firm Gen-to-Load Flows and historic Firm Transmission Service flows, down to 0%) relative to the total impacts of all other Reciprocal Entities' impacts on the Flowgate. For example, if Reciprocal Entity A had a 30 MW impact on the Flowgate and Reciprocal Entity B had a 70 MW impact on the Flowgate, the Historic Ratios would be 30% and 70%, respectively.

6. The same rules defined in the "Market-Based Operating Entity Congestion Management" Section 5 of this document for use in determining Firm Transmission Service impacts (NNL) shall apply when performing Allocations
7. Additional rules to be used when considering Firm Transmission Service impacts are defined later within this section.
8. For each firm Allocation run described above, the managing entity will take the following steps to determine Allocations down to 0% for each of the Flowgates, in both the forward and reverse direction, they are assigned to manage:
    a. Retrieve the Flowgate limit.
    b. Subtract the current Transmission Reliability Margin (TRM) value (may be zero).
    c. Subtract the sum of all historically-determined Firm Flow impacts for all entities based on impacts greater than or equal to 5%.
    d. Accommodation of Capacity Benefit Margin (CBM)
        - If no capacity remains after step (c), entities' firm Allocation is limited to this amount (i.e., their Firm Flow impacts from impacts of 5% or greater), and the firm Allocation for the entity with functional control over the Flowgate is increased by the current CBM value (may be zero).
        - If capacity does remain after step (c), and the sum of all Reciprocal Entities' impacts below 5% plus CBM is less than the remaining capacity from step (c), that capacity is allocated to the Reciprocal Entities pro-rata based on their Firm Flow impacts due to impacts less than 5% up to the total amount of their Firm Flow impacts due to impacts less than 5%.
        - If there is not sufficient capacity for all impacts below 5% plus CBM to be accommodated, the current CBM value is subtracted from the remaining capacity from step (c), and granted to the entity with functional control over the Flowgate. Any capacity remaining is allocated to the Reciprocal Entities pro-rata based on their Firm Flow impacts due to impacts less than 5%.
    e. Any remaining capacity, after step (d) will be considered firm and allocated to Reciprocal Entities based on their Historic Ratio (as described in step 5). If the remaining capacity allocated to the entity with functional control over the Flowgate meets or exceeds the current CBM value, no further effort is needed. If the remaining capacity is less than the CBM, capacity will first be reduced by the CBM, and the entity with functional control over the Flowgate will be granted the capacity needed to support the CBM. In addition each Reciprocal Entity (including the entity with functional control over the Flowgate) will receive allocations determined as a pro-rata share of the remaining capacity (as described in Step 5).
    f. Upon completion of the Allocation process, the managing entity will compare the current preliminary Allocation to the previous Allocations. For any given Flowgate, the larger of the Allocations will be considered the Allocation (*i.e.*, an Allocation cannot decrease). Once all preliminary Allocations have been compared and the final Allocation determined, the managing entity will

distribute the Allocations to the appropriate Reciprocal Entities. This Allocation will consist of the firm Gen to Load limit and a portion of capability that can be used either for Firm Transmission Service or additional firm Gen-to-Load service.

9. For the non-firm Allocation run described above, the managing entity will take the following steps to determine Allocations down to 0% for each of the Flowgates, in both the forward and reverse direction, they are assigned to manage. For each hour, the managing entity shall:
    a. Retrieve the Flowgate limit.
    b. Subtract the current TRM value (may be zero).
    c. Subtract the sum of all hourly historically-determined Firm Flow impacts for all entities based on impacts greater than or equal to 5%.
    d. Subtract the sum of all hourly historically-determined Firm Flow impacts for all Reciprocal Entities based on impacts less than 5%.
    e. Any remaining capacity will be allocated to Reciprocal Entities based on their Historic Ratio (as described in step 5).
    f. The two-day ahead firm Allocation is subtracted from the total entity Allocation (from steps c, d, and e).
        - If the result is positive, this value will be equivalent to the Priority 6-NN Allocation/limit, and the Firm Flow Limit for 0% Market Flows will be the two-day ahead firm Allocation.
        - If the result is negative or zero, the Priority 6-NN Allocation will be calculated by subtracting the total entity Allocation (from steps c, d, and e) from the two-day ahead firm Allocation. The Firm Flow Limit for 0% Market Flows will be the equivalent of the total entity allocation.
    g. Upon completion of the Allocation process, the managing entity will distribute the Allocations to the appropriate Reciprocal Entities. These Allocations will be considered non-firm network service.

When a Market-Based Operating Entity is uploading Firm Flow Limits to the IDC, they will be responsible for ensuring that any firm Allocations are properly accounted for. If firm Allocations are used to provide additional firm network service, they should be included in the Firm Flow Limit. If they are used to provide additional Firm Transmission Service, they should not be included in the Firm Flow Limit.

The Market-Based Operating Entities will maintain in real-time their Firm Transmission Service and Network Non-Designated service impacts, within their respective firm and Priority 6 total Allocations. The Firm Transmission Service impacts will be based on schedules. The Operating Entities participating in the Coordinated Process for Reciprocal Flowgates will respect their allocations when granting Firm Transmission Service.

Using the derived firm Allocation value, the Market-Based Operating Entity may choose to enter this value as a Flowgate limit for the respective Flowgate. If entered as a Flowgate limit, the Day-Ahead unit commitment will not permit flows to exceed this value as it selects units for this commitment. Market-Based Operating Entities will use the Flowgate limit to restrict unit outage scheduling for a Coordinated Flowgate when maintenance outage coordination indicates possible congestion and there is recent TLR activity on a Flowgate.

As Reciprocal Entities gain more experience in this process, implement and enhance their systems to perform the Firm Flow calculations and Allocations, they may change the timing requirements for the Forward Coordination Process by mutual agreement.

6.6.1 Determining Firm Transmission Service Impacts

Firm impacts used in the Allocation process incorporate the Firm Transmission Service flows. Similar to the network service calculation described previously, to calculate each Firm Transmission Service transaction's impact on the Flowgate, the following process is utilized:

1. Utilize a base case to determine the Generation Shift Factor for the source Control Area with respect to a specific Flowgate.
2. Utilize the same base case to determine the Generation Shift Factor for the sink Control Area with respect to that Flowgate.
3. Utilize superposition to calculate the TDF for that source to sink pair with respect to that Flowgate.
4. Multiply the transactions energy transfer by the TDF to determine that transactions flow on the Flowgate.

Summing each of these impacts by direction will provide the directional Firm Transmission Service impact on the Flowgate.

Combining the directional Firm Transmission Service impacts with the directional NNL impacts will provide the directional Firm Flows on the Flowgate.

6.6.2 Rules for Considering Firm Transmission Service

1. Firm Transmission Service and Designated Network Resources that have an OASIS reservation are included in the calculation.
2. Reciprocal Entities will utilize a Freeze Date of April 1, 2004. Reciprocal Entities will utilize a reference year of June 1, 2004 through May 31, 2005 for determining the confirmed set of reservations that will be used in the Allocation process. The reference year is used such that reservation impacts in a given month in the reference year are used for each comparable month going forward in the Allocation process. For example, the Allocations for July 2004, July 2005, and July 2006 etc. will always use the July 2004 reservation impacts from the reference year. Confirmed reservations received after the Freeze Date will not be considered.
3. A potential for duplicate reservations exists if a transaction was made on individual CA tariffs (not a regional tariff) and both parties to the transaction (source and sink) are Reciprocal Entities. In this case, each Reciprocal Entity will receive 50% of the transaction impact.

4. To the extent a partial path reservation is known to exist, it will have 100% of its impacts considered on Reciprocal Coordinated Flowgates owned by the party that sold the partial path service, split 50/50 between the Source Reciprocal Entity and the Sink Reciprocal Entity, and 0% of its impacts considered on other Reciprocal Coordinated Flowgates.
5. Because reservations that are totally within the footprint of the regional tariff do not have duplicate reservations, these reservations will have the full impact considered even though both parties to the transaction (source and sink) are within the boundaries of the regional tariff and will be considered Reciprocal Entities, split 50/50 between the Source Reciprocal Entity and the Sink Reciprocal Entity, which in this case are the same. Similar to the firm network service calculation, the Firm Transmission Service calculation:
    a. Will consider all reservations (including those with less than 5% impact)
    b. Will base response factors on the topology of the system for the period under consideration.
    c. In general, will not make a generation-to-load calculation where a reservation exists.

6.6.3 Limiting Firm Transmission Service

The Flowgate Allocations down to 0% will represent the share of total Flowgate capacity (STFC) that a particular entity has been allocated. This STFC represents the maximum total impact that entity is allowed to have on that Flowgate.

In order to coordinate with the existing AFC process, it is necessary that this number be converted to an available STFC (ASTFC) which represents how much Flowgate capability remains available on that Flowgate for use as Transmission Service. In order to accomplish this, the entity receiving STFC will do the following:

Step	Example
1.) Start with the STFC	100
2.) Add all forward Gen to Load impacts (down to 0%) and all Reverse Gen to Load impacts (down to 0%) to obtain the Net Gen to Load impacts. The Gen to Load impacts should be based on the *best estimate* of firm Gen-to-Load Flow for the time period being evaluated.	42 + (-20) = 22
3.) Subtract the net Gen to Load impacts from the STFC	100 – 22 = 78
4.) Subtract the CBM to produce an interim STFC	78 – 0 = 78
5.) Determine the Transmission	58 + (0.15 (-45)) =

Service impacts of service that has been sold. By default, it should be assumed that 100% of forward service and 15% of counterflowing service will be scheduled and used. However, if Flowgate "owner" uses different percentages in their AFC calculation and the Flowgate manager's calculation engine support it, percentages other than 100% and 15% may be used. Add all forward Transmission Service impacts (down to 0%) and all appropriate reverse Transmission Service impacts (down to 0%) to obtain the weighted net Transmission Service impacts. The Transmission Service impacts should be based on the *current* set of reservations in effect for the time period being evaluated (*not* the historic reservation set)	58 + (-6.75) ≈ 58 + (-7) = 51
6.) Subtract the weighted net Transmission Service impacts from the Interim STFC. The result is the ASTFC	78 – 51 = 27

The ASTFC values for Reciprocal Coordinated Flowgates will be posted on OASIS along with the Allocation results. This ASTFC can then be compared with the AFC calculated through traditional means when evaluating firm requests made on OASIS.

If the AFC value is LOWER than the ASTFC value, the AFC value should be utilized for the purpose of approving/denying service. In this case, while the Allocation process might indicate that the entity has rights to a particular Flowgate through the Allocation process, current conditions on that Flowgate indicate that selling those rights would result in overselling of the Flowgate, introducing a reliability problem.

If the AFC value is HIGHER than the ASTFC value, the ASTFC value should be utilized for the purpose of approving/denying service. In this case, while the AFC process might indicate that the entity can sell more service than the Allocation might indicate, the entity is bound to not sell beyond their Allocation.

If a Reciprocal Entity uses all of its firm Allocation and desires to obtain additional capacity from another Reciprocal Entity who has remaining capacity, that additional capacity may be obtained using the procedures documented below.

6.7 Sharing or Transferring Unused Allocations

Reciprocal Entities shall use the following process for the sharing or transferring of unused Allocations down to 0% between each other.

6.7.1 General Principles

This process includes the following general principles in the treatment of unused Allocations

1. A desire to fully utilize the Reciprocal Entities' Allocations such that in real-time, an unused Allocation by Reciprocal Entities is caused by a lack of commercial need for the Allocation by Reciprocal Entities and not by restrictions on the use of the Allocation.
2. For short-term requests (less than one year) where the lack of an Allocation could otherwise result in the denial of Transmission Service requests, there should be a mechanism to share or acquire a remaining Allocation on a non-permanent basis for the duration of the short-term transmission service requests. The short-term Allocation transfers would revert back to the Reciprocal Entity with the original Allocation after the short term request expires.
3. For long-term requests (one year or longer) where the lack of an Allocation could otherwise cause the construction of new facilities, there should be a mechanism to acquire a remaining Allocation such that new facilities are built only because they are needed by the system to support the transaction and not because of the Allocation split between Reciprocal Entities. Long-term Allocation transfers would apply to the original time period of the request including any roll-over rights that are granted for such requests.
4. Due to limitations on the frequency of transferring updated Allocation values and AFC's between the Reciprocal Entities, the Reciprocal Entities will utilize buffers to reduce the risk of overselling the same service, and to set aside a portion of the unused Allocation for the owner of the unused Allocation to accommodate any request that they may receive. The buffer will be reduced on a Flowgate based upon factors such as the rating of the Flowgate and operational experience, with the goal to maximize the use of the unused Allocation. The rationale for reducing the buffer is that potentially significant amounts of Transmission Service (up to many times the buffer amount) may be denied otherwise by the non-owner of the unused Allocation.

6.7.2 Provisions for Sharing or Transferring of Unused Allocations:

1. Based upon the proposed infrastructure for Allocation calculations, daily Allocations are available for 7 days into the future and Weekly and Monthly Allocations are available up to 18 months into the future. Sharing and transferring of unused Allocations will be limited to the granularity of the Allocation calculations.
2. The Reciprocal Entities will share or transfer their unused firm Allocations during the time periods up until day ahead with the goal to fully utilize the Allocations.
3. This sharing or transfer of the unused Allocation will occur automatically for short-term Transmission Service requests, and manually for long-term (one year or greater) Transmission Service requests. The Reciprocal Entity that has been requested to transfer unused Allocations to the other Reciprocal Entity for a long-term request shall respond within 5 business days of receipt of the transfer request.
4. The Reciprocal Entities will post information available to the other Reciprocal Entity on all requests granted that shared or acquired the other Reciprocal Entity's Allocation on a daily basis for review.

5. Sharing an Unused Allocation During the Near-Term

   The Reciprocal Entities will share their Allocations during the near-term (the first 7 days up until day ahead or a mutually agreed upon timeframe) with the goal to fully utilize the Allocations once in real-time through an automated process.

   This sharing of the unused Allocation during the near-term will occur such that an unused Allocation that has not already been committed for use by either Firm Transmission Service or for market service will be made available to the other Reciprocal Entities for their use to accommodate Firm Transmission Service requests submitted on OASIS.

   Other firm uses of the transmission system involving generation to load deliveries, which are not evaluated via automated request evaluation tools, will be handled via off-line processes. The core principles to be applied in such cases include:

   a. A sharing of Allocation can occur.
   b. The sharing shall be done on a comparable basis for the market and non-market entities.
   c. The sharing is not related to projected Firm Flow Limits absent new DNRs or Transmission Service submitted on OASIS.
   d. The details of the process will include such items as which DNRs are covered, time-lines for designations and comparable evaluation of DNRs. If the details of this process cannot be agreed upon, there shall be no sharing of the unused Allocations during the near-term.

   A buffer will limit the amount of Allocation that can be shared for short-term requests during automated processing of the Allocation sharing process. The owner of the unused Allocation is not restricted by the buffer. The buffer is defined as a percentage of the last updated unused Allocation, provided that the buffer shall not be allowed to be less than a certain MW value. For example, a 25% or 20 MW buffer would mean that the requesting entity can use the other Reciprocal Entity's unused Allocation while making sure that the other entity's unused Allocation does not become smaller than 25% of the reported unused amount or 20 MW. The specific provisions of the buffer shall be mutually agreed to by the Reciprocal Entities prior to implementing a sharing of unused Allocation. The buffer will not be used in manual processing of Allocation sharing requests. For manual processing of requests, the owner of the unused Allocation will share the remaining unused Allocation to the extent they do not need the unused Allocation for pending Transmission Service requests.

For the sharing of unused Allocations in the near-term, the Allocations are <u>not</u> changed and should congestion occur, the IDC obligations for the giving Reciprocal Entity will be in accordance with its original Allocation. The receiving Reciprocal Entity will not be required to retract or annul any service previously granted due to the sharing of Allocations.

6. <u>Acquiring an Unused Allocation Beyond the Near Term</u>

When a Reciprocal Entity does not have sufficient Allocation on a Flowgate to approve a firm point-to-point or network service request made on OASIS and evaluated via automated request evaluation tools and the other Reciprocal Entity has a remaining Allocation, the deficient Reciprocal Entity will be able to acquire an Allocation from the Reciprocal Entity with the remaining Allocation. This Allocation must not already be committed for other appropriate uses, as agreed to by the Reciprocal Entities, and sufficient AFC must remain on the Flowgate, or will be created, to accommodate the request. Such cases will be handled via automated processes.

Other firm uses of the transmission system involving generation to load deliveries, which are not evaluated via automated request evaluation tools, will be handled via off-line processes. The core principles to be applied in such cases include:

a. A transfer of Allocation can occur.
b. The transfer shall be done on a comparable basis for the market and non-market entities.
c. The transfer is not related to projected Firm Flow Limit absent new DNRs or Firm Transmission Service submitted on OASIS.
d. The details of the process will include such items as which DNRs are covered, time-lines for designations and comparable evaluation of DNRs If the details of this process cannot be agreed upon, there shall be no transfer of the Allocation for the time period beyond the near term.

A buffer will limit the amount of Allocation that can be acquired for these requests during automated processing of the Allocation transfer process. The owner of the unused Allocation is not restricted by the buffer. The buffer is defined as a percentage of the last updated unused Allocation, provided that the buffer shall not be allowed to be less than a certain MW value. For example, a 25% or 20 MW buffer would mean that the requesting entity can use the other Reciprocal Entity's unused Allocation while making sure that the other entity's unused Allocation does not become smaller than 25% of the reported unused amount or 20 MW. The specifics of the buffer shall be mutually agreed to by the Reciprocal Entities prior to implementing a transferring of unused Allocation. The buffer will not be used in manual processing of Allocation sharing requests. For manual processing of requests, the owner of the unused Allocation will transfer the remaining unused Allocation to the extent they do not need the unused Allocation for pending Transmission Service requests.

The determination of whether the remaining Allocation has already been committed will be established based on OASIS queue time. All requests received prior to the queue time will be considered prior commitments to the remaining Allocation, while such requests are in a pending state (e.g. study status) or confirmed state. Requests received after the queue time will be ignored when determining whether remaining capacity has already been committed.

In the event that prior-queued requests are still in a pending state (i.e. not yet confirmed), the Reciprocal Entity requesting a transfer of unused Allocations may await the resolution of any prior-queued requests in the other Reciprocal Entity's OASIS queue before relinquishing its ability to request an Allocation transfer.

For the transfer of unused Allocations, the Reciprocal Entity's Allocations will be changed to reflect the Allocation transfer at the time the Allocation transfer request is processed. To the extent the request is not ultimately confirmed, the Allocation will revert back to the original Reciprocal Entity with the remaining Allocation. For yearly requests, the transfer of the Allocation applies to the original time period of the request including any roll-overs that are granted.

6.8 Application of Firm Flow Limits in the IDC

In addition to the responsibilities described earlier in "Market-Based Operating Entity Congestion Management" Section 5 of this document, Market-Based Operating Entities will have an additional obligation, on Reciprocal Coordinated Flowgates, to further quantify their Non-Firm GTL flows into two (2) separate priorities in the IDC: Non-Firm Network (6-NN), and Non-Firm Hourly (2-NH). Within the IDC, the priorities will be determined as follows:

1. If the GTL flow exceeds the sum of the Firm Flow Limit and the 6-NN Allocation, then:
   2-NH = GTL flow – (Firm Flow Limit + 6-NN Allocation)
   6-NN = 6-NN Allocation
   7-FN = Firm Flow Limit
2. If the GTL flow exceeds the Firm Flow Limit but is less than the 6-NN Allocation, then:
   2-NH = 0
   6-NN = GTL flow – Firm Flow Limit
   7-FN = Firm Flow Limit
3. If the GTL flow does not exceed the Firm Flow Limit, then

2-NH = 0
6-NN = 0
7-FN = GTL flow

4. If the tag associated with EAR is converted to Market Flow and excluded by the IDC, the Market Flow shall have a priority that is no higher than it would have been if the tag was not excluded by IDC. This provision aims to keep the application of these tags consistent between the Market Flow used in market-to-market and the GTL calculation performed by the IDC and used in TLR.

All other aspects of this data remain identical to those described in “Market-Based Operating Entity Congestion Management” Section 5.

6.9 Real-time Operations Process for Market-Based Operating Entities

6.9.1 Market-Based Operating Entity Capabilities

Capabilities remain as described in “Market-Based Operating Entity Congestion Management” Section 5.

6.9.2 Market-Based Operating Entity Real-time Actions

Procedures remain as described in “Market-Based Operating Entity Congestion Management” Section 5. However, as described above, additional information regarding the firmness of those Non-Firm GTL flows will be communicated as well. A portion will be reported as 6-NN, while the remainder will be reported as 2-NH. This will provide additional ability for the IDC to curtail portions of the Non-Firm GTL flows earlier in the TLR process.

6.10 Requirements to Combine Allocations with Non-Reciprocal Entity

The following requirements must be satisfied for a Combining Party to incorporate a Non-Reciprocal Entity's load and the associated generation serving that load into the Reciprocal Entity's Allocation calculations:

1. The Non-Reciprocal Entity's load and associated generation serving that load participates in the market of the Combining Party pursuant to a FERC-accepted agreement(s).
2. The Non-Reciprocal Entity has not placed its transmission facilities under the Open Access Transmission Tariff of the Combining Party, nor has the Non-Reciprocal Entity executed a transmission owner agreement or membership agreement, or equivalent thereof, of the Combining Party.
3. The Non-Reciprocal Entity is wholly embedded (i.e., the load and associated generation serving that load are included in Allocations, Market Flows, and IDC GTL calculations) into the Combining Party's Control Area footprint in accordance with the CMP.
4. The Combining Party must treat the Non-Reciprocal Entity's impacts in the IDC, Market Flow, Firm Flow Limit, and Firm Flow Entitlement calculations consistently as the Combining Party does its own impacts in accordance with this CMP. The Non-Reciprocal Entity's load and associated generation serving that load otherwise needs to be eligible for inclusion in firm Allocations, Firm Flow Limit, and Firm Flow Entitlement under the terms of this CMP.
5. Any transmission facilities owned by the Non-Reciprocal Entity must be treated comparably to the transmission facilities of other Reciprocal Entities consistent with the terms of the CMP.
6. The Combining Party must provide notice to the other Reciprocal Entities of its plans to combine allocations within sixty (60) calendar days of making a filing at the FERC that would result in a Non-Reciprocal Entity's load and associated generation serving that load being combined with the Combining Party or upon combining Allocations (whichever occurs first). Even though a situation in which a Combining Party has proposed to combine Allocations with a Non-Reciprocal Entity may satisfy requirement numbers 1 through 5 of this list, this does not preclude other Reciprocal Entities from raising any objection pursuant to the dispute resolution process of a joint operating agreement or by filing a Section 206 complaint with the FERC if the proposed combination of Allocations would be inconsistent with this CMP or produces a result that is unjust and unreasonable.

Section 7 - Appendices

Appendix A- Glossary

Agreement – Agreement shall mean this Seams Operating Agreement Between the Midcontinent Independent System Operator, Inc. and Manitoba Hydro, as amended from time to time, including all attachments, appendices, and schedules.

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.

Available Flowgate Capability (AFC) – the applicable rating of the applicable Flowgate less the projected loading across the applicable Flowgate less TRM and CBM. The firm AFC is calculated with only the appropriate Firm Transmission Service reservations (or interchange schedules) in the model, including recognition of all roll-over Transmission Service rights. Non-firm AFC is determined with appropriate firm and non-firm reservations (or interchange schedules) modeled.

AFC Flowgate – A Flowgate for which an entity calculates AFC's.

Combining Party – Combining Party shall mean a Reciprocal Entity that is incorporating the load and associated generation serving that load from a Non-Reciprocal Entity into the Reciprocal Entity's Allocations pursuant to Section 6.10 of this CMP.

Control Area – shall mean an electric power system or combination of electric power systems to which a 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 (**CF**) - Shall mean a Flowgate impacted by an Operating Entity as determined by one of the five 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 Network Resource – A resource that has been identified as a designated network resource pursuant to a transmission provider's Open Access Transmission Tariff.

EIDSN – Eastern Interconnection Data Sharing Network.

External Asynchronous Resource[1] **(EAR)** – A Resource representing an asynchronous DC tie between the synchronous Eastern Interconnection grid and an asynchronous grid that is supported within the Transmission Provider Region through Dynamic Interchange Schedules in the Day-Ahead Energy and Operating Reserve Market and/or Real-Time Energy and Operating Reserve Market. External Asynchronous Resources are located where the asynchronous tie terminates in the synchronous Eastern Interconnection grid.

[1] External Asynchronous Resource is specific to the MISO tariff , MISO, FERC Electric Tariff, Module A, § 1.E "External Asynchronous Resource" (33.0.0).

Firm Flow – The estimated impacts of Firm Transmission Service on a particular Coordinated or Reciprocal Coordinated Flowgate.

Firm Flow Limit – The maximum value of Firm Flows an entity can have on a Coordinated or Reciprocal Coordinated Flowgate, based on procedures defined in Sections 4 and 5 of this document.

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

Firm Transmission Service – The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption or similar quality service offered by transmission providers by contract that do not require the filing of a rate schedule. Firm Transmission Service only includes firm point-to-point service, network designated transmission service and grandfather agreements deemed firm by the transmission provider as posted on OASIS.

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

Freeze Date – the cutoff date chosen by Reciprocal Entities to be used in the calculation of Historic Firm Flows.

Generation-to-Load (GTL) – The calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving load within an Operating Entity's Control Area, as specified in NAESB BPS WEQ-008 starting version 3.3.

Generator Priority Schedules (GPS) – A schedule that indicates the Transmission Service curtailment priority of the generator output, as specified in NAESB BPS WEQ-008-9.1.3.

Generator Shift Factor – A factor to be applied to a generator's expected change in output to determine the amount of flow contribution that change in output will impose on an identified transmission facility or Flowgate, referenced to a swing bus.

Historic Firm Flow – The estimated total impact an entity has on a Reciprocal Coordinated Flowgate when considering the impacts of (1) its historic Designated Network Resources serving native load, and (2) imports and exports, based on Firm Transmission Service 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.

Load Shift Factor – A factor to be applied to a load’s expected change in demand to determine the amount of flow contribution that change in demand will impose on an identified transmission facility or Flowgate, referenced to a swing bus.

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 Market-Based Operating Entity’s market area.

Market Flows - The calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity’s market.

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

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

Non-Firm Market Flow – That portion of Market Flow related to a Market-Based Operating Entity’s market operations in excess of that entity’s Firm Market Flow.

Non-Reciprocal Entity – Non-Reciprocal Entity shall mean an Operating Entity that is not a Reciprocal Entity.

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.

Party or Parties – Party or Parties refers to each party to this Agreement or both, as applicable.

Parallel Flow Visualization (PFV) – Conceptual ideas captured in NAESB BPS WEQ-008 starting with version 3.3.

Reciprocal Coordination Agreement - An agreement between Operating Entities to implement the reciprocal coordination procedures defined in the CMP.

Reciprocal Coordinated Flowgate (RCF) – A Flowgate that is subject to reciprocal coordination by Operating Entities, under either this Agreement (with respect to Parties only) or a Reciprocal Coordination Agreement between one or more Parties and one or more Third Party Operating Entities. An RCF is:

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

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

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

Reciprocal Entity – an entity that coordinates the future-looking management of Flowgate capacity in accordance with a Reciprocal Coordination Agreement as developed under Section 6 of this document, or a congestion management process approved by the Federal Energy Regulatory Commission; provided such congestion management process is identical or substantially similar to this CMP.

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

Tag Secondary Network Transmission Service Method (TSNT) - A method for determining the Transmission Service curtailment priority of the Secondary Network Transmission Service using e-Tags, as specified in NAESB BPS WEQ-008-1.9.2.

Third Party – Third Party refers to any entity other than a Party to this Agreement.

Tie Line – Tie Line shall mean a circuit connecting two Control Areas.

Transfer Distribution Factor – the portion of an interchange transaction, typically expressed in per unit, flowing across a Flowgate.

Transmission Service – services provided to the transmission customer by the transmission service provider to move energy from a point of receipt to a point of delivery.

Appendix B - **Determination of Marginal Zone Participation Factors**

In order for the IDC to properly account for tagged transactions into and out of the market area, a Market-Based Operating Entity using the Marginal Zone methodology will need to provide participation factors representing the facilities contributing to the tagged transactions. The facility or facilities contributing to each export tagged transaction is the source of the export tagged transaction. The facility or facilities contributing to each import tagged transaction is the sink of the import tagged transaction.

The Market-Based Operating Entity will be required to define a set of zones that can be aggregated into a common distribution factor that is representative of the market area. This information must be shared and coordinated with the IDC. Following this step, the Market-Based Operating Entity must then send to the IDC participation factors for those zones. These participation factors represent the percentages of how these zones are providing marginal megawatts as a result of dispatch of resources in market operations to serve transactions. Data sets for each external source/sink are required, which correspond to:

- An IMPORT data set, which indicates the participation of facilities accommodating the energy imported into the market area, and
- An EXPORT data set, which indicates the participation of facilities accommodating the energy exported out of the market area.

The methodology used by the Market-Based Operating Entity to determine the Marginal Zone participating factors will be determined through collaboration of the Market-Based Operating Entity with the IDC working group.

Participation Factor Calculation

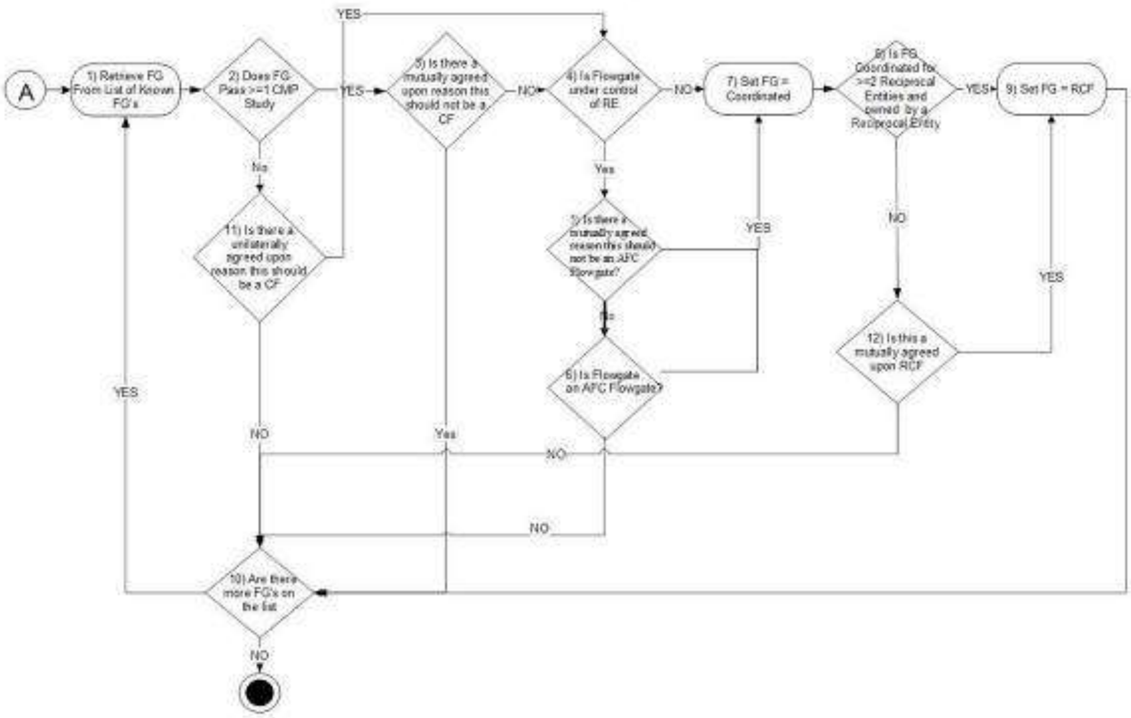
The Market-Based Operating Entity will use the real-time system conditions to calculate the marginal zone participation factors, which reflect the impacts of tagged transactions. These will establish, for imports and exports, a set of participation factors that, when summed, will equal 100 percent.

Appendix C - **Flowgate Determination Process**

This section is has been added to clarify:

- How initial Flowgates are identified (Figure C-1, Table C-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 C-2, Table C-2)
- How often Flowgates are changed (Figure C-2, Table C-2)

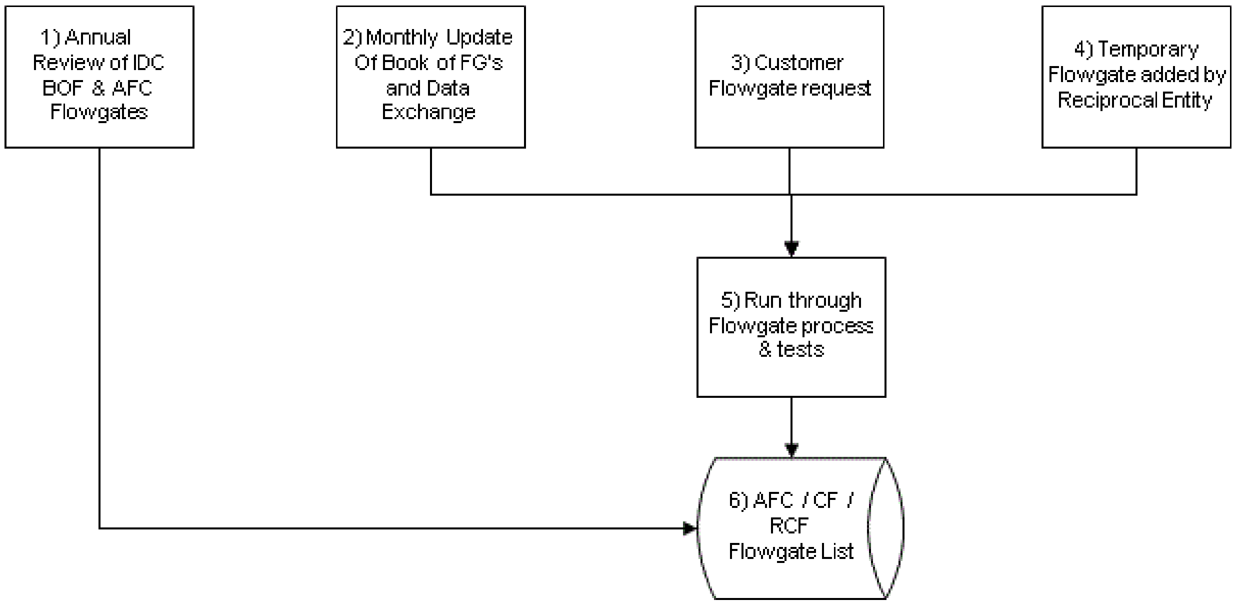
Figure C -1
Determine AFC Flowgates,
Coordinated Flowgates, and Reciprocal
Coordinated Flowgates



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 Reciprocal Entity 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 five 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.	See Impacted Flowgate Determination - Section 3
3	Is There a Mutually Agreed Upon Reason This Should Not Be A Coordinated Flowgate	Determine if there is a mutually agreed reason, despite passing one of the five tests, why this FG should not be considered Coordinated.	• If there is no mutually agreed reason why this FG should not be considered coordinated, test whether FG is under control of a Reciprocal Entity. • If there is a mutually agreed reason why this FG should not be considered coordinated, record the reason proceed to Step 10.	
4	Is the Flowgate under control of a Reciprocal Entity	If the Flowgate is under the control of a non-reciprocal entity and the Flowgate passes one of the five tests it will be treated as a Coordinated Flowgate.	• If the Flowgate is not under control of a Reciprocal Entity proceed to Step 7. • If the Flowgate is under control of a Reciprocal Entity Proceed to Step 5.	
5	Is there a mutually agreed reason this should not be AFC Flowgate?	Determine if there is a mutually agreed reason, despite qualifying as a Coordinated Flowgate, why this Coordinated Flowgate is not included in the AFC process.	• If there is a mutually agreed reason to not include the Coordinated Flowgate in the AFC process proceed to Step 7. • Otherwise proceed to Step 6	
6	Is Flowgate an AFC Flowgate	A check is done to determine if the Flowgate controlled by a Reciprocal Entity is in its AFC process.	• If the Flowgate is in the AFC process or in the process of being added to the AFC process proceed to Step 7. • Otherwise proceed to Step 10	

Step	Activity	Requirements	Detailed Description	Additional Documentation
7	Set FG = Coordinated	The FG would be coordinated for the entity.	• The FG would be considered a CF.	
8	Is FG Coordinated for >= 2 Reciprocal Entities and "owned" by a Reciprocal Entity	Determine whether the FG is coordinated for two or more Reciprocal Entities	• If the FG is coordinated for two or more Reciprocal Entities and it is "owned" by one of the 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 and "owned" by one of the entities, determine if it is a mutually agreed upon RCF.	CM Process -Section 6
9	Set FG = RCF	Set the Flowgate equal to a Reciprocal Coordinated Flowgate.	• Set the Flowgate equal to a Reciprocal Coordinated Flowgate. • Proceed to Step 10.	
10	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. • Proceed to Step 1 if another FG requires evaluation. • Otherwise, the process ends.	
11	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 five tests.	• If an entity decides to make this a coordinated FG, proceed to Step 4. • Otherwise, proceed to Step 10.	
12	Is This a Mutually Agreed Upon RCF	Determine if there is a mutually agreed reason this should be considered a Reciprocal Coordinated Flowgate.	• If there is no mutually agreed reason this should be considered an RCF, leave it as coordinated and check for more FGs. • If there is a mutually agreed reason this should be considered an RCF, mark it as such. • If Reciprocal Entities decide to make the Flowgate Reciprocal proceed to Step 9. • Otherwise, proceed to Step 10.	

Figure C-2
Flowgate Review and Customer
Flowgate Request



Steps	Activity	Requirements	Detailed Description	Additional Documentation
1	Annual Review of the BOFs and AFC FGs	A review will be performed annually or more often as requested by Reciprocal Entities (CMPWG). Retrieve the FG from the list of FGs for the entity running the process. Study 1 in section 3.2.1 of the CMP is not required for this annual review.	• Except for Study 1 in section 3.2.1 of the CMP, the FGs will be run through the process summarized in figure C-1.	
2	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 C-1.	
3	Temporary Flowgate added by Reciprocal Entity	Any temporary Flowgate added by a Reciprocal Entity will also be subject to the tests and processes in Step 5.	• Any temporary Flowgates added by a Reciprocal Entity will be run through the process summarized in figure C-1	
4	Run Through FG Process and Tests	Run through FG Determination Process, figure C-1	• Any FGs being reviewed or added will be run through the process summarized in figure C-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.	

Appendix D--Training

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

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

1. The ability to take projected net system flows between an Operating Entity’s 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 another RC Operator when the RC System Operator has a temporary Flowgate that they believe requires the implementation of the “Flowgate on the Fly” process.

Appendix E—Reserved

Appendix F--Reserved

Appendix G - Allocation Adjustment for New Transmission Facilities and/or Designated Network Resources

1. Guiding Principles

The following guiding principles will be used in determining the allocation adjustments for New Transmission Facilities and/or Designated Network Resources.

- Principle 1 (Non-builder held harmless) – To the extent possible, the non-building entity will receive the same overall impacts in its allocations.
- Principle 2 (Builder receives benefits) – To the extent possible, the building entity will receive any benefit to the transmission system that result from the system upgrade.

To the extent these two principles conflict, the Non-Builder Held Harmless Principle will have priority over the Builder Receives Benefit Principle.

2. New Transmission Facilities That Do Not Involve New DNR or New Firm Transmission Service

To the extent a new transmission facility causes a significant decrease in flow on a Reciprocal Coordinated Flowgate the change in the allocation will be assigned to the Reciprocal Entity with functional control of the new transmission facility. Otherwise, the normal allocation procedures will be followed and no allocation adjustments for new transmission facilities will be made.

Significant impact is defined as a 3% change in flow that occurs to an OTDF Flowgate and a 5% change in flow that occurs to a PTDF Flowgate with the addition of the new facility. The 3% and 5% are measured as a percentage of the Flowgate TTC (sometimes called Total Flowgate Capability (TFC)).

The allocation adjustment will be assigned to the Reciprocal Entity with functional control of the new transmission facility. Both the original allocation and the allocation adjustment are assigned to the Reciprocal Entities. To the extent a group of transmission owners installs a new facility that includes multiple Reciprocal Entities and the new transmission facility results in a change in transfer capability on one or more RCFs, these Reciprocal Entities will work in collaboration to determine appropriate adjustments to each Reciprocal Entity's allocation on all significantly impacted RCFs.

An analysis will be performed both with and without the new facility to determine whether there is a significant impact on one or more RCFs. The analysis and any subsequent allocation adjustments will coincide with the expected in-service date of the new facility. The inclusion of the new transmission facility in such an analysis is dependent on having a commitment that the new facility has or is expected to receive all of the appropriate approvals and will be installed on the date indicated.

In order to qualify for an allocation adjustment, the new transmission facility must not only create a significant change in flows, it must also be a significant change to the transmission system (i.e. a new line or transformer that creates a significant change to flows on one or more RCFs). The addition of a new generator without transmission additions (other than the generation interconnection) is not covered by this process for new transmission facility additions. A change in the rating of an RCF may qualify as a significant change to the transmission system and be eligible to receive an allocation adjustment even though it does not result in a change in flows.

For stability limited Flowgates, a new generator, reactive device or change to a remedial action scheme may contribute to a change in the transfer limitation of stability limited Flowgates. Where this occurs and the addition is being made for the specific purpose of changing the transfer limitation of stability limited Flowgates, an allocation adjustment will be provided to the Reciprocal Entity responsible for the new generator, reactive device or change to a remedial action scheme. By receiving an allocation adjustment, this new generator, reactive device or change to a remedial action scheme will not also be included in the historical usage calculation to avoid double-counting of the impacts.

Not all new transmission facilities that significantly impact RCFs involve a change in flows. A new facility may be added that changes the rating of an RCF but has minimal impact on the flow (i.e. reconductoring, replacing a wave trap (WT) or current transformer (CT), replacing a transformer). In this case, each Reciprocal Entity's historical usage flow will remain constant but the rating of the Flowgate will either increase or decrease. The Reciprocal Entity responsible for the new facility will receive an allocation adjustment for rating increases. There will be no allocation adjustments for rating decreases.

There is an equity issue involving new transmission facilities that result in an increased rating. Where a new facility involves minimal cost change (such as replacing either a WT or CT, replacing a jumper, replacing a switch, changing a CT setting, etc.), there have already been significant costs incurred on a larger conductor that allows the increased rating to occur. As long as the Reciprocal Entity making the minimal cost change is also responsible for the conductor, it is the appropriate Reciprocal Entity to receive the allocation adjustment. However, if different Reciprocal Entities own the conductor versus are responsible for making the minimal cost change, there is an equity issue if the entire allocation adjustment is given to the Reciprocal Entity responsible for making the minimal cost change. The Reciprocal Entities shall negotiate a mechanism to share in the allocation adjustment.

3. New Transmission Facilities that Involve New DNR or New Firm Transmission Service

Where a new transmission facility is added as part of an approved new usage of the transmission system (either a new DNR or a new Firm Transmission Service), the Reciprocal Entity responsible for the new facility has two choices on the treatment of this combination. First, in recognition that they have addressed transmission concerns associated with the new DNR or new Firm Transmission Service, the combination of the new transmission facility and new DNR/Firm Transmission Service will be added to the base model used in the historic usage impact calculation. The new DNR or new Firm Transmission Service will be treated as if it met the Freeze Date. To the extent the new transmission facility and its associated new DNR or new Firm Transmission Service will not occur until a future time period, they will not appear in the historic usage impact calculation until after the in-service/start date. The inclusion of the new transmission facility and associated DNR/Firm Transmission Service is dependent on having a commitment that both have been approved and will occur on the date indicated. If no such commitment exists, these additions will not be included in the historic usage impact calculation. By making this choice to include the new transmission facility and DNR/Firm Transmission Service in the historic usage impact calculation, the NNL allocation will consider the impact of both. This may result in increased NNL allocation to all Reciprocal Entities after considering historic usage impacts (down to 0%). However, the Reciprocal Entity that builds the new transmission facility will not receive any special treatment (NNL allocation adjustment) because of the new transmission facility. This inclusion of a new DNR or new Firm Transmission Service only applies where associated new transmission facilities have been added to accommodate the new transmission usage.

Second, the Reciprocal Entity that builds the new transmission facility associated with a new DNR or new Firm Transmission Service can receive an NNL allocation adjustment and must honor that allocation when they apply the new DNR or new Firm Transmission Service in their use of NNL allocations. The Reciprocal Entity determines the impact of the new transmission facility without the new DNR or new Firm Transmission Service to calculate any adjustments to the NNL allocations (the same process documented in the previous section "New Transmission Facilities that Do Not Involve New DNRs or New Firm Transmission Service). The Reciprocal Entity will use the remaining NNL allocation that has not been committed to other uses for the new DNRs or new Firm Transmission Service.

The Reciprocal Entity responsible for the combination of new transmission facility and new DNR/Firm Transmission Service will make a single choice (either one or two) that applies to all RCFs that are significantly impacted by the combination. There is no opportunity to have a different selection on different RCFs that are all impacted by the same combination.

4. Allocation Adjustment Peer Review

When reviewing the allocation adjustments, if an impacted Reciprocal Entity finds a situation where the rule set does not produce a satisfactory outcome, the impacted Reciprocal Entity may request a review by the CMPWG. The impacted Reciprocal Entity will present the unsatisfactory results and a proposed alternative. If the CMPWG agrees to the proposed alternative it will be implemented as an exception, and the CMPC will be notified of the exception prior to implementation. If the CMPWG does not agree, the impacted Reciprocal Entity can seek further review by the CMPC. The impacted Reciprocal Entity will present its proposed alternative and the CMPWG member(s) will present their concerns to the CMPC for the CMPC to take action. All exceptions approved by the CMPWG or CMPC will be documented for future reference.

Depending on the nature of the upgrade, the impact of the new facility will be held in abeyance pending completion of the review. This means for a rating change, the prior rating will continue to be used in the model update process pending completion of the review. This means for a flow change, the new facility will be recognized in the model update process. The impacts will be calculated using the normal (socialized) allocation process and no allocation adjustments will be made pending completion of the review. These reviews should be completed in a timely manner.

Appendix H – Application of Market Flow Threshold Field Test Conditions

MISO, PJM and SPP participated in a NERC approved Market Flow threshold field test from June 1, 2007 to October 31, 2009. The purpose of the field test was to determine a Market Flow threshold percentage that allows the three Regional Transmission Organizations (RTOs) to consistently meet their relief obligations during TLR without jeopardizing reliability. Although the field test was able to achieve a success rate close to 100% based on MISO data using a 5% threshold, the following conditions were applied to the field test results:

- Market Flows were evaluated 30 minutes after implementation of the TLR curtailment.
- A 5 MW dead-band (or 10% of the relief obligation for relief obligations greater than 50 MW) was applied to the Target Market Flow such that once actual Market Flows were within the dead-band, it was considered a success meeting the relief obligation.
- There were no instances where MISO was able to meet its relief obligation if more than 30 MW must be removed within 30 minutes. The field test found the amount of Market Flow that must be removed in 30 minutes and not the size of the relief obligation is an indicator whether the market will be successful.

Since the NERC ORS applied the three conditions above to the field test results in order to demonstrate a high success rate, these same conditions will be applied when the Market-Based Operating Entities have relief obligations on external Flowgates during TLR.

The field test results are only applicable to Flowgates that are external to each of the RTOs and does not include internal Flowgates (internal to that specific RTO) or market-to-market Flowgates (internal to one of the three RTOs but subject to market-to-market provisions with another RTO). The reason for excluding internal Flowgates and market-to-market Flowgates is because the three RTOs use market redispatch to control total flow and to maintain reliability. As the Reliability Coordinator for the Flowgate, the three RTOs are responsible for the reliability of their own Flowgate and must manage total flow in order to meet their reliability responsibility. As described in the field test final report, by controlling total flow, the three markets effectively meet their relief obligation.