Joint Operating Agreement
Between the
Midwest Independent Transmission System Operator, Inc.
And
Southwest Power Pool, Inc.

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ARTICLE I
RECITALS

This Joint Operating Agreement ("Agreement") dated this 1st day of December, 2004, by and between Southwest Power Pool, Inc. ("SPP") an Arkansas not-for-profit corporation having a place of business at 415 North McKinley, #800 Plaza West, Little Rock, AR 72205, and the Midwest Independent Transmission System Operator, Inc. ("MIDWEST ISO"), a Delaware non-stock corporation having a place of business at 701 City Center Drive, Carmel, Indiana 46032. SPP and MIDWEST ISO may be individually referred to herein as "Party" or collectively as "Parties".

WHEREAS, SPP is a North American Electric Reliability Council ("NERC") Regional Reliability Organization and an independent provider of reliability coordination, tariff administration, and scheduling services to its customers and interconnected member electric systems in the Southwest part of the United States;

WHEREAS, SPP has filed a petition with the Federal Energy Regulatory Commission ("FERC") for recognition as a Regional Transmission Organization ("RTO"), and is developing processes and systems to operate energy imbalance, congestion management, and other ancillary service markets in a phased approach;

WHEREAS, the MIDWEST ISO is the RTO that provides operating and reliability functions in portions of the Midwest and Canada. The MIDWEST ISO also administers the MIDWEST ISO Tariff for transmission and other services on its grid, and is developing processes and systems to operate markets to facilitate day-ahead and real-time energy transactions and financially firm transmission rights;

WHEREAS, FERC has ordered each Party to develop mechanisms to address inter-regional coordination;

WHEREAS, on February 27, 2004, the Parties entered into the System Operation, Planning and Market Development Memorandum of Understanding ("MOU"), which provides for the establishment of a Seams Agreement Coordinating Committee to develop recommendations on coordination activities that will improve reliability and reduce barriers to electricity trading within the regions and to negotiate a Joint Operating Agreement that will contractually bind the Parties to these coordination activities; and

WHEREAS, in accordance with good utility practice and in accordance with the directives of FERC, the Parties seek to establish exchanges of information and establish or confirm other arrangements and protocols in furtherance of the reliability of their systems and efficient market operations, and to give effect to other matters required by FERC;

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 AND DEFINITIONS

Section 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 and as AFC is further defined in Section 5.1.7.

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.

2.1.5 "EHV" shall mean Extra High Voltage, as defined in Section 11.2.2.

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

2.1.7 "FERC" shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

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

2.1.9 "ICCP/ISN" shall mean those common communication protocols adopted to standardize information exchange.

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

2.1.11 "IDCWG" shall mean the NERC Working Group established to provide advice on the IDC.

2.1.12 "IPSAC" shall mean Inter-regional Planning Stakeholder Advisory Committee.

2.1.13 "JPC" shall mean Joint Planning Committee.

2.1.14 "MMWG" shall mean the NERC working group that is charged with multi-regional modeling.

2.1.15 "MW" shall mean megawatt of power.

2.1.16 "MWh" shall mean megawatt hour of energy.

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

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

2.1.19 "OATI" shall mean the entity that has been retained by NERC, or successor organization, to maintain the IDC system.

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

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

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

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

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

2.1.25 "RCF" shall mean Reciprocal Coordinated Flowgate.

2.1.26 "RTO" shall mean Regional Transmission Organization.

2.1.27 "SACC" means the Seams Agreement Coordinating Committee, established in the Memorandum of Understanding between the Parties.

2.1. 28 "SDX System" shall mean the system used by NERC to exchange system data.

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

2.1.30 "TRM" shall mean the Transmission Reliability Margin, which is that amount of transmission transfer capability necessary to ensure that the interconnected transmission network is secure under a reasonable range of uncertainties in system conditions.

2.1.31 "TTC" shall mean Total Transfer Capability.

Section 2.2 Definitions.

2.2.1 "a & b multipliers" shall mean the multipliers that are applied to TRM in the planning horizon and in the operating horizon to determine non-firm AFC/ATC. The "a" multiplier is applied to TRM in the planning horizon to determine non-firm AFC/ATC. The "b" multiplier is applied to TRM in the operating horizon to determine non-firm AFC/ATC. The "a & b" multipliers can vary between 0 and 1, inclusive. They are determined by individual transmission providers based on network reliability concerns.

2.2.2 "Agreement" shall have the meaning stated in the preamble.

2.2.3 "Available Flowgate Rating" shall have the meaning stated in Section 5.1.8.

2.2.4 "Confidential Information" shall have the meaning stated in Section 18.1.

2.2.5 "Congestion Management Process" means that document which is Attachment 2 hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.6 "Control Area(s)" shall mean an electric power system or combination of electric power systems to which a common automatic generation control scheme is applied.

2.2.7 "Coordinated Flowgate(s)" shall mean a Flowgate impacted by an Operating Entity as determined by one of the four studies detailed in Section 3 of the attached document entitled "Congestion Management Process." For a Market-Based Operating Entity, these Flowgates will be subject to the requirements under the Congestion Management portion of the Congestion Management Process (Sections 4 and 5). A Coordinated Flowgate may be under the operational control of a Third Party.

2.2.8 "Coordinated Operations" means all activities that will be undertaken by the Parties pursuant to this Agreement.

2.2.9 "Coordinated System Plan" shall have the meaning stated in Section 9.3.2.

2.2.10 "Economic Dispatch" shall mean the sending of dispatch instructions to generation units to minimize the cost of reliably meeting load demands.

2.2.11 "Effective Date" shall have the meaning stated in Section 13.1.

2.2.12 “Firm Flow” shall mean the estimated impacts of firm transactions under Network and Point-to-Point service on a particular Coordinated Flowgate.

2.2.13 “Firm Flow Limit” shall mean the maximum value of firm flows an entity can have on a Reciprocal Coordinated Flowgate.

2.2.14 “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.

2.2.15 “Freeze Date” shall mean April 1, 2004, as that date is applied in the Congestion Management Process.

2.2.16 “Intellectual Property” shall mean (i) ideas, designs, concepts, techniques, inventions, discoveries, or improvements, regardless of patentability, but including without limitation patents, patent applications, mask works, trade secrets, and know-how; (ii) works of authorship, regardless of copyright ability, including without limitation copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

2.2.17 “Interconnected Reliability Limit” (“IRL”) shall mean the value (such as MW, MVAR, Amperes, Frequency, or Volts) derived from, or a subset of, the System Operating Limits, which if exceeded, could expose a widespread area of the bulk electrical system to instability, uncontrolled separation(s) or cascading outages, either under existing system conditions or following a contingency.

2.2.18 “Intermittent Generation” shall mean a resource that cannot be scheduled and controlled to produce the anticipated energy.

2.2.19 “Market” shall mean the energy and/or ancillary services market facilitated by the Parties pursuant to FERC Order No. 2000.

2.2.20 “Market Flows” shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources within a Market Based Operating Entity’s market (excluding tagged transactions).

2.2.21 “Memorandum of Understanding” shall mean that certain predecessor agreement between the Parties to develop this Joint Operating Agreement dated January 30, 2004.

2.2.22 “MIDWEST ISO” has the meaning stated in the preamble of this Agreement.

2.2.23 “Network Upgrades” shall mean those facilities located beyond the point of interconnection of the generating facility to the transmission grid.

2.2.24 “Notice” shall have the meaning stated in Section 18.10.

2.2.25 "Operating Entity" shall mean 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.

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

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

2.2.28 "Priority level of service" shall refer to the appropriate level of service established by NERC in its protocols.

2.2.29 "Reciprocal Coordination Agreement" shall mean an agreement between Operating Entities to implement the reciprocal coordination procedures defined in the CMP.

2.2.30 "Reciprocal Coordinated Flowgate(s)" or "RCF" shall mean 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. A RCF is:

- A CF that is (a) within the operational control of MIDWEST ISO or SPP, and (b) affected by the transmission of energy by both Parties; or
- A CF that is (a) affected by the transmission of energy by one or both 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
- A CF that is designated by agreement of both Parties as a RCF.

2.2.31 "Reciprocal Entity" shall mean any entity that coordinates the future-looking management of flowgate capacity in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.32 "RCF Base Usage" shall mean the long-term firm and network service usage of RCFs.

2.2.33 "Reliability Coordinator" ("RC") shall mean that party approved by NERC to be responsible for reliability for a region.

2.2.34 "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.

2.2.35 "SPP" Has the meaning stated in the preamble of this Agreement.

2.2.36 "State Estimator" shall mean that computer model that computes the state (voltage magnitudes and angles) of the transmission system using the network model and real-time measurements. Line flows, transformer flows, and injections at the buses are calculated from the known state and the transmission line parameters. The state estimator has the capability to detect and identify bad measurements.

2.2.37 "System Operating Limit" ("SOL") shall mean the value (such as MW, Mvar, Amperes, Frequency, or Volts) that satisfies the most limiting of the prescribed operating criteria for a specified system configuration to ensure operation within acceptable reliability criteria.

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

2.2.39 "Transmission Owner" shall mean any entity defined as such under the SPP OATT, MISO OATT, or MAPP OATT.

2.2.40 "Voltage and Reactive Power Coordination Procedure" are the procedures under Article XI for coordination of voltage control and reactive power requirements.

Section 2.3 Rules of Construction.

Section 2.3.1 <u>No Interpretation Against Drafter</u>. In addition to their roles as reliability coordinators, and the functions and responsibilities associated therewith, 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.

Section 2.3.2 <u>Incorporation of Preamble and Recitals</u>. The Preamble and Recitals of this Agreement are hereby incorporated into the terms and conditions of this Agreement and made a part thereof.

Section 2.3.3 <u>Meanings of Certain Common Words</u>. 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.

Section 2.3.4 <u>Certain Headings</u>. Certain sections of Articles IV and V contain descriptions of the purpose or requirements stated in those sections. These statements of purpose are to provide background information to assist in the interpretation of the requirements. The absence of a stated purpose with respect to any requirement does not diminish the enforceability of the requirement. If a provision in Articles IV and V is not delineated as "purpose," "background," or "definition," it is a requirement.

Section 2.3.5 <u>NERC Policies and Procedures</u>. All activities under this Agreement will meet or exceed the applicable NERC policies or procedures as revised from time to time.

Section 2.3.6 <u>Congestion Management Process</u>. The Congestion Management Process is hereby incorporated into this Agreement and in the event there is a conflict between this Agreement and the Congestion Management Process, the Congestion Management Process prevails. The Congestion Management Process may be amended from time to time upon agreement of the Parties. Any disputes arising under the Congestion Management Process are subject to the dispute resolution provisions contained in Section 14.2 of this Agreement. All involved Parties in a flowgate dispute shall follow the dispute resolution processes and appeal rights under Section 3 of the Congestion Management Process.

Section 2.3.7 <u>Scope of Application</u>. Each Party will perform this Agreement in accordance with its terms and conditions with respect to each Transmission Owner for which it administers transmission service and, in addition, each Control Area for which it serves as Reliability Coordinator.

ARTICLE III
OVERVIEW OF COORDINATION AND INFORMATION EXCHANGE

Section 3.1 Ongoing Review and Revisions. The Parties have agreed to the coordination and exchange of data and information under this Agreement to ensure system reliability and efficient market operations 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 exchange of data will change from time to time throughout the term of this Agreement. The Parties agree that the 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 requirements and protocols. Each Party will negotiate in good faith in response to such revisions the other Party may propose from time to time.

Section 3.2 Definitions of Phases and Applicable Time Periods. The Parties' coordination and exchange of data and information shall occur in three (3) phases. Phase 1, "Non-Market to Non-Market", shall commence upon execution of this Agreement. Phase 2, "Market to Non-Market," shall commence upon the initiation of a Market within the SPP footprint or the MIDWEST ISO footprint where such a market did not exist prior to the Effective Date and ending when SPP and MIDWEST ISO have initiated Markets. Phase 3, "Market to Market," shall commence when SPP and MIDWEST ISO have implemented Markets and such commencement shall be with respect only to Control Areas included in those Markets. Each phase includes continuation of all elements of prior phases except any elements that, due to initiation of a later phase, are determined by both Parties to be impracticable to perform.

Section 3.3 Elements of Phase 1, Phase 2, and Phase 3.

Section 3.3.1 <u>Phase 1</u>. Upon the commencement of Phase 1, Non-Market to Non-Market, the Parties shall commence performance of each of the following elements:

(a) Exchange of data and information between the Parties as described in Articles IV and V;
(b) Calculation of ATC/AFC as described in Article V;
(c) Coordination of Outages as described in Article VII;
(d) Joint operation of emergency procedures as described in Article VIII;
(e) Coordinated regional transmission expansion planning as described in Article IX;
(f) Coordinated scheduling checkouts as described in Article X;
(g) Voltage control and reactive power coordination as described in Article XI;
(h) Additions to, or deletions from, the foregoing, to which the Parties may agree from time to time or as ordered by the FERC.

Section 3.3.2 Phase 2. Phase 2, Market to Non-Market, consists of the continuation of all Phase 1 elements (except those that have been completed or due to other circumstances cannot be continued) and, in addition, may consist of the following elements:

(a) Reciprocal coordination of flowgates as described in Article VI;
(b) Implementation of the NERC-approved Congestion Management Process as described in Section 12.1.

Section 3.3.3 Phase 3. Phase 3, Market to Market, consists of the continuation of all Phase 1 and Phase 2 elements (except those that have been completed or due to other circumstances cannot be continued) and, in addition, may consist of the following elements:

(a) Generation redispatch and coordination, as described in Articles VIII and XII (pursuant to NERC Policies 5 and 9);
(b) Consistency in calculating energy prices at the market borders as described in Section 12.3.1;
(c) Additions to, or deletions from Items (a) through (g) of Section 3.3.1 and Items (a) and (b) of Section 3.3.2, to which the Parties may agree from time to time, including agreements prior to initiation of Phase 2 and in accordance with Section 3.1, or as ordered by the FERC.

ARTICLE IV
EXCHANGE OF INFORMATION AND DATA

Section 4.1 Phase 1, Non-Market to Non-Market - Exchange of Operating Data.

Purpose: Sharing data is necessary to facilitate effective coordination of operations and to maintain regional system reliability while assuring the maximum commercial flexibility for market participants.

Requirements: During Phase 1, Non-Market to Non-Market, the Parties will exchange the following types of data and information:

(a) Real-Time and Projected Operating Data;
(b) SCADA Data;
(c) EMS Models;
(d) Operations Planning Data; and
(e) Planning Information and Models.

Each Party shall provide the data identified in items (a) through (e) above to the other Party with respect to all Transmission Owners for which it administers transmission service and Control Areas for which it acts as Reliability Coordinator on the Effective Date and during the term of this Agreement, whether or not such an entity is contemplated as of the Effective Date.

The Parties also shall exchange such information as the Market Monitors of SPP and MIDWEST ISO may request in order to facilitate monitoring in accordance with the Parties' respective FERC-approved market monitoring plans.

To facilitate the exchange of all such data, each Party will 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. 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.

The Parties agree to exchange data in a timely manner consistent with existing defined formats or such other formats to which the Parties may agree. If any required data exchange 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 will jointly seek to complete development of the format within thirty (30) days of such Notice.

The Parties agree that various components of the data exchanged under this Section is Confidential Information and that:

(a) The Party receiving the Confidential Information shall treat the information in the same confidential manner as its governing documents require it treat the confidential information of its own members and market participants.

(b) The receiving Party shall not release the producing Party's Confidential Information until expiration of the time period controlling the producing Party's disclosure of the same information, as such period is described in the producing Party's governing documents from time to time. As of the Effective Date, this period is six (6) months with respect to bid or pricing data and seven (7) calendar days for transmission data identified in 4.1.1(a) after the event ends.

(c) All other prerequisites applicable to the producing Party's release of such Confidential Information have been satisfied as determined by the producing Party.

Additional information which the Parties agree to exchange during Phases 2 or 3 is indicated in *italics* in Section 4.1.1 to Section 4.1.4.10 below.

Section 4.1.1 Real-Time and Projected Operating Data.

Requirements: The Parties will exchange two categories of operating data: real-time information and projected information, as follows.

(a) The real–time operating information consists of:

- Generation status of the units in each Party's Region;
- Transmission line status;
- Real-time loads;
- Scheduled use of reservations;
- TLR information, *including in Phases 2 and 3, calculation of Market Flows*;
- *Redispatch information, including the next most economical generation block to decrement/increment; and*
- *Real-time constraints*.

(b) Projected operating information consists of:

- Unit commitment/merit order for generators in the Party's Region;
- Maintenance schedules for generators and transmission facilities in the Party's Region;
- Firm purchase and sales;
- The planned and actual operational start-up dates for any permanently added, removed or significantly altered transmission segments; and
- The planned and actual start-up testing and operational start-up or change dates for any permanently added, removed or significantly altered generation units.

Section 4.1.2 Exchange of SCADA Data.

Background: NERC Policy 4, Appendix 4B, "Electric System Security Data," describes the types of data that Control Areas are expected to provide, and Reliability Coordinators are expected to share with each other as explained in Policy 4B, "Reliability Coordination – Operational Security Information."

Requirements:

(a) The Parties shall exchange requested transmission power flows, measured bus voltages and breaker equipment statuses of their bulk transmission facilities 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, but in any event no more than one (1) week 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 will comply with all governing confidentiality agreements executed by the Parties relating to ICCP/ISN data.

(e) The Parties shall exchange SCADA data consisting of:

(i) Status measurements 69 kV and above (breaker statuses) (as available and required to observe for reliability as the respective Parties may determine);

(ii) Analog measurements 69 kV and above (flows and voltages) (as available and required to observe for reliability as the respective Parties may determine);

(iii) Generation point measurements, including generator output for each unit in MW and MVARS, as available;

(iv) Load point measurements, including bus loads and specific loads at each substation in MW and MVARS, as available;

(v) Control Area net interchange;

(vi) Control Area total load;

(vii) Control Area operating reserves; and

(viii) Identification of other real-time data available through ICCP/ISN.

Section 4.1.3 <u>Models</u>.

Purpose: EMS models contain detailed representations of the transmission and generation configurations within each Party's Region and neighboring systems. The Parties depend upon EMS models for reliability coordination and market operations. The regular exchange of models is to ensure that each Party is using current and up-to-date representations of the other Party

Requirements: The Parties will exchange their detailed EMS models once a year in CIM, but shall provide each other with updates of the CIM files as new data becomes available. This yearly exchange will include the ICCP/ISN mapping files, identification of individual bus loads, seasonal equipment ratings and one-line drawings that will be used to expedite the model conversion process. The Parties will also exchange updates that represent the incremental changes that have occurred to the EMS model since the most recent update.

Section 4.1.4 <u>Operations Planning Data</u>.

Purpose: Operations planning data, which defines how a system was planned and built, is basic information needed to coordinate planning and operations between the Parties.

Requirements: Upon the written request of a Party, the other Party shall provide the information specified in Sections 4.1.4.1 through 4.1.4.10 inclusive, or any components thereof. Each request shall specify the information sought and the frequency upon which it would 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. Operations planning data is not generally considered confidential but to the extent any of this data overlaps previously defined operating data in Section 4.1.2, it is considered Confidential Information.

Section 4.1.4.1 - Flowgates:

(a) Flowgate definitions including seasonal TTC, TRM, CBM, a & b multipliers;
(b) Flowgates to be added on demand;
(c) *List of Coordinated Flowgates*;
(d) List of Flowgates to recognize when processing transmission service (if different than list of Coordinated Flowgates); and
(e) Requirements under Section 5.1.7.

Section 4.1.4.2 - Transmission Service Reservations:

(a) Daily list of all reservations, hourly increment of new reservations;
(b) List of reservations to exclude; and
(c) Requirements under Sections 5.1.4 and 5.1.5.

Section 4.1.4.3 – AFC Data:

Each Party will meet a minimum periodicity for calculating and making available AFCs to each other. The minimum periodicity depends on the service being offered. Each Party will provide the following AFC data to the other Party:

(a) Hourly for first seven (7) days posted at a minimum, once per hour;
(b) Daily for days eight (8) through thirty-one (31) posted at a minimum, once per day; and
(c) Monthly for months two (2) through eighteen (18) posted at a minimum, once per month.

Section 4.1.4.4 - Load Forecast:

(a) Hourly for next seven (7) days, daily for days eight (8) through thirty-one (31), and monthly for months two (2) through eighteen (18) submitted once a day;
(b) Identity of the Control Area or zone within a Control Area for which the forecast is given;
(c) Indicate whether this forecast includes transmission system losses, and if it does, indicate what the percent losses are;
(d) Identify non-conforming loads;
(e) Indicate how municipal entities, cooperatives and other entity 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
(f) Requirements under Section 5.1.6.

Section 4.1.4.5 - Generator Data:

(a) Unit owner, bus location in model;
(b) Seasonal ratings, PMIN, PMAX, QMIN, QMAX;
(c) Station auxiliaries to extent gross generation has been reported; and
(d) Regulated bus, target voltage and actual voltage.

Section 4.1.4.6 – Designated Network Resources:

(a) Network Integration Transmission Service Specifications;
(b) Designated Network Resource information;
(c) Indication of treatment as pseudo tie or dynamic/static schedules;
(d) Rules for sharing output between joint owners; and
(e) Transmission arrangements.

Section 4.1.4.7 -Control Area Net Interchange from Reservations and Tags:

(a) Any grandfathered agreements that do not appear in OASIS; and
(b) If tags and reservations can no longer be used to develop Control Area or zone net interchange, then provide hourly unit commitment information for all generators in the Control Area/zone.

Section 4.1.4.8 - Dynamic Schedules:

(a) List of dynamic schedules;
(b) Identification of dynamic schedules that are being used to move load into the Control Area or out of the Control Area;
(c) *Identification of marginal generation zones*; and
(d) Requirements under Section 5.1.11.

Section 4.1.4.9 - List of Controllable Devices:

(a) Phase shifters;
(b) DC lines; and
(c) Back-to-back AC/DC converters.

Section 4.1.1.10 - Generation and Transmission Outages:

(a) Generation outages that are planned or forecast, as soon as practicable after they are identified, including all data specified in Section 5.1.1;
(b) 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
(c) Notification of all forced outages of both generation and transmission resources, not to exceed 30 minutes after they are identified.

Section 4.2 Phase 2 and Phase 3, Market to Non-Market and Market to Market - Exchange of Operating Data.

Requirements: Prior to the initiation of Phases 2 and 3, Market to Non-Market and Market to Market, the Parties shall confer regarding the need to exchange any information other than that identified for exchange in Section 4.1, and shall make agreements for exchange of such information during Phases 2 and 3 as is necessary to achieve the objectives of this Agreement.

Section 4.3 Cost of Data and Information Exchange.

Requirements: Each Party shall bear its own cost of providing information to the other Party pursuant to Sections 4.1 and 4.2.

ARTICLE V
ATC/AFC CALCULATIONS

Section 5.1 ATC/AFC Protocols - Phase 1, Non-Market to Non-Market.

Purpose: The calculation of Total Transfer Capability ("TTC") and Available Transfer Capability ("ATC") is a forecast of transmission capacity that may be available for use by transmission customers. Use of transmission capacity in one system can impact the loadings, voltages and stability of neighboring systems. Because of this interrelationship, neighboring entities must exchange pertinent data for each entity to determine the TTC and ATC/AFC values for its own transmission system. The exchange of data related to calculation of TTC and ATC is necessary to assure reliable coordination, and also to permit either Party to determine if, due to lack of transmission capacity, it must refuse a transmission reservation in order to avoid potential overloading of facilities.

As of the Effective Date, the Parties use the NERC SDX System to exchange the status of generators rated greater than 150 MW, outages of all interconnections and other transmission facilities operated at greater than 230 kV, and peak load forecasts. This system has the capability to house daily data for the next seven (7) days, weekly data for the next month, and monthly data for the next year. Continued use of this tool, and associated commitments under this Agreement, will assure the Parties' ability to make reliable calculations efficiently.

Section 5.1.1 Generation Outage Schedules.

Requirements: Each Party shall provide the other with projected status of generation availability over the next twelve (12) months. The Parties will update this data no less than once daily for the full posting horizon and more often as required by system conditions. The data will include complete generation maintenance schedules and the most current available generator availability data, such that each Party is aware of each "return date" of a generator from a scheduled or forced outage. If the status of a particular generator of less than 150 MW is used within a Party's TTC/ATC/AFC calculation, the status of this unit shall also be supplied.

Section 5.1.2 Generation Dispatch Order.

Purpose: Dispatch information combined with unit availability information permits each Party to develop a reasonably accurate dispatch for any modeled condition. This methodology is more advantageous than scaling all available generation to meet generation commitments within an area and then increasing all generation uniformly to model an export, or uniformly decreasing all generation to model an import. While excluding nuclear generation or hydro units from this scaling would provide some level of refinement, this approach is inadequate to identify transmission constraints and determine rational TTC/ATC/AFC values. On the other extreme, although economic data could be shared to allow an economic dispatch to be determined for each level of generation commitment, this level of refinement is generally unnecessary, and the data is likely to be considered confidential by the generation owners, and therefore unavailable. The exchange of typical generation dispatch order or generation participation factors of all units on a control area basis and other data under this Agreement will permit each Party to appropriately model future transmission system conditions.

Requirements: As necessary to permit a Party to develop a reasonably accurate dispatch for any modeled condition, each Party will provide the other Party with a typical generation dispatch order or the generation participation factors of all units on an affected control area basis. The generation dispatch order will be updated as required by changes in the status of the unit; however, a new generation dispatch order need not be provided more often than prior to each peak load season.

Section 5.1.3 Transmission Outage Schedules.

Requirements: Each Party will provide the other Party with the projected status of transmission outage schedules above 230 kV 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 will 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. If the status of a particular transmission facility operating at voltages less than 230 kV is critical to the determination of TTC and ATC/AFC of a Party, the status of this facility will also be provided.

Section 5.1.4 Transmission Interchange Schedules

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.

Requirements: Each Party will make available to the other 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 downloading by the other Party as required by its own process and schedules, or shall request NERC to modify the IDC to allow for selected interrogation by the Parties

Section 5.1.5 Transmission Service Requests.

Purpose: Beyond the operating horizon, the impacts of existing transmission service requests are also necessary for the calculation of TTC and ATC/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 *pro forma* tariff allows firm service on a given path to be redirected as non-firm service on any other path. In addition, the ultimate transmission customer may not have, 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, prior to scheduling, it is difficult to associate reservations involving multiple Transmission Providers that may be used to complete a single transaction, double counting in the ATC/AFC determination process is a possibility. It is therefore acknowledged that certain reservations respecting one Party are not required to be incorporated into transmission models developed by the other Party.

Requirements:

(a) Each Party will make available to the other Party, on an FTP site, actual transmission service request information for integration into each Party's TTC/ATC/AFC determination process.

(b) Each Party will develop practices for modeling transmission service requests, including external requests, and netting practices for any allowance of counterflows created by reservations in electrically opposite directions. Each Party will provide the other Party with the procedures developed and implemented to model intra-Party requests, requests on external parties, and reservation netting.

(c) Each Party shall also create and maintain a list of reservations from its OASIS that should not be considered in ATC/AFC calculations. Reasons for these exceptions include, for example, grandfathered agreements that grant access to more transmission than is necessary for the related generation capacity and unmatched intra-Party partial path reservations. If a Party does not include it in its own evaluation, it should be excluded in other Parties' analysis.

Section 5.1.6 Load Data.

Requirements: The Parties will exchange 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 next seven (7) day horizon, the Parties shall either supply hourly load forecasts or they shall supply daily peak load forecasts with a load profile. All load forecasts will be provided on a Control Area basis, with further granularity provided to reflect load forecasts by company within the Control Area.

Section 5.1.7 Calculated Firm and Non-firm Available Flowgate Capability.

Definitions: The Available Flowgate Capability ("AFC") is the applicable rating of the flowgate less the projected loading across the particular flowgate less Transmission Reliability Margin and Capacity Benefits Margin. The Firm AFC is calculated with only the appropriate firm transmission service reservations (or interchange schedules) in the model, 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.

Purpose: Data exchange 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 Party respects the other Party's flowgates.

Requirements:

(a) The Parties will exchange Firm and Non-firm AFC for all relevant flowgates.

(b) Each Party will accept or reject transmission service requests based upon projected AFCs applicable to both Parties' Flowgates and to Reciprocal Coordinated Flowgates; and

(c) Each Party will limit approvals of transmission service reservations, including roll-over transmission service, so as to not exceed the sum of the thermal capabilities of the tie lines that interconnect the Parties, provided that firm transmission service customers with terms of one year or longer retain the rollover rights and reservation priority granted to them under the applicable Party's OATT, and further provided that if explicitly stated in the applicable service agreement, a Party may limit rollover rights for new long-term firm service if there is not enough ATC to accommodate rollover rights beyond the initial term.

Section 5.1.8 Available Flowgate Rating.

Definition: The Available Flowgate Rating is the maximum amount of power that can flow across that interface without overloading (either on an actual or contingency basis) any element of the flowgate. The flowgate rating is in units of megawatts. If the flowgate is voltage or stability limited, a megawatt proxy is determined to ensure adequate voltages and stability conditions.

Requirements: The Parties will exchange (seasonal, normal and emergency) Available Flowgate Ratings as well as all limiting conditions (thermal, voltage, or stability). The Parties will update this information in a timely manner as required by changes on the transmission system.

Section 5.1.9 Identification of Flowgates.

Requirements: Each Party shall consider in its TTC and ATC/AFC determination process all flowgates: (i) that may initiate a TLR event, (ii) that are significantly impacted by either Party's transactions, or (iii) as mutually agreed between the Parties. A Party's transactions are deemed to significantly impact another Party's flowgates if they have a response factor equal to or greater than the response factor cut-off used by the owning Party. The Parties in their AFC determination and transmission service processing efforts shall use the response factor cut-off that the owning/operating Party uses for its flowgates.

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

Requirements:

(a) A mechanism will be instituted between the Parties to ensure that all significant system changes of a neighbor are incorporated in each Party's TTC/ATC/AFC calculation model, within sixty (60) days after the Effective Date of this Agreement. Although this information and a host of very detailed data are included in the MMWG cases, this data exchange mechanism will address the 'major' changes that should be included in the TTC/ATC/AFC calculation models in a more timely manner. This type of data change will be similar to the 'New Facilities' Listings usually included in inter-regional reports; however, explicit modeling information will need to be supplied along with the listing. This data exchange will occur no less often than prior to each peak load season.

(b) In addition, the Parties agree to exchange TTC/ATC/AFC calculation models of their transmission systems as soon as mechanisms can be established to facilitate this exchange.

Section 5.1.11 Dynamic Schedule Flows.

Requirements: 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 signing of this Agreement. All dynamic schedule flows and tags will be submitted in accordance with NERC policy and procedures.

Section 5.1.12 Coordination of TRM Values.

Requirements: Each Party shall make transmission capacity available for reserve sharing by including the impacts of the other Party's generation outages in its TRM values. The Parties will coordinate and share the necessary information for the determination of these impacts no less than annually.

Section 5.2 ATC/AFC Protocols – Phases 2 and 3, Market to Non-Market and Market to Market. The Parties will address any appropriate revisions to the requirements set forth in Section 5.1.1 through Section 5.1.11 that may arise in the implementation of Phases 2 and 3.

Section 5.3 Sharing Contract Path Capacity – All Phases. The Parties have agreed to the following phased approach to the elimination of such contract path limits:

(a) If the Parties have contract paths to the same entity, the combined contract path capacity will be made available for use by both Parties. This will not create new contract paths for either Party that did not previously exist. SPP will not be able to deal directly with companies with which it does not physically or contractually interconnect and the MIDWEST ISO will not be able to deal directly with companies with which it does not physically or contractually interconnect.

(b) When the MIDWEST ISO and SPP commence operation of energy markets, the sharing of contract path capacity where the MIDWEST ISO and SPP have existing contract path capacity to the same entity will continue to exist. The MIDWEST ISO and SPP may need to resolve any coordination issues such that the combined contract capacity is not exceeded by the operation of the two markets. This phase will still not create new contract paths for the Parties.

(c) When a Joint and Common Market exists between the MIDWEST ISO and SPP as is expected, the sharing of contract path capacity between the MIDWEST ISO and SPP will occur on a complete basis. All physical connections to the combined MIDWEST ISO and SPP RTOs will be available for use by the market. Whether the physical path connections are within the MIDWEST ISO or SPP will not affect a customer's participation in the market. Only actual physical limitations will impact how the customer is able to use these connections to the market.

ARTICLE VI
RECIPROCAL COORDINATION OF FLOWGATES

Section 6.1 Reciprocal Coordination of Flowgates Operating Protocols - Phase 2, Market to Non-Market. As used in this Article and the Congestion Management Process:

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

"Reciprocal Coordinated Flowgate" or RCF shall mean a Coordinated Flowgate with respect to which a reciprocal agreement has been written and to which reciprocal coordination procedures as defined in the Congestion Management Process apply. An RCF is either (1) a CF affected by the transmission of energy by both Parties, or by both Parties and one or more other Reciprocal Entities, or (2) a Coordinated Flowgate, which both Parties mutually agree should be an RCF, and for which reciprocal coordination will occur.

An RCF may be under the operational control of one of the Parties, or may be under the operational control of a Third Party Reciprocal Entity.

6.1.1 **Reciprocal Coordinated Flowgates.** In order to coordinate congestion management proactively, each Party agrees to respect the other Party's determinations of AFC/ATC and calculations of firmness for real-time operations applicable to the Party's CFs. Additionally, each Party agrees to respect the Allocations defined by the Reciprocal Allocation Process set forth in the Congestion Management Process.

6.1.2 **Coordination Process for Reciprocal Coordinated Flowgates.** The Parties will establish and finalize the process and timing for exchanging their respective ATC/AFC calculations and Firm Flow calculations/allocations with respect to all RCFs. Further, the process will allocate Flowgate capacity on a future-looking basis, including the allocation of Firm and Non-Firm Capability for use in both internal dispatch and selling of transmission service. The Congestion Management Process sets forth the procedure for reciprocal coordination. For any Flowgate comprised of one or more controllable devices, the historically determined Firm Flow on the Flowgate and any allocated rights to that Flowgate under this process are subject to the operating practices of the controllable device. To the extent the controllable device is able to maintain scheduled flows, there are no parallel flows on the Flowgate and a historical allocation based on parallel flows will not occur. In this instance, the use of the Flowgate will be limited to entities that have arranged transmission service across the interface formed by the controllable device. To the extent the controllable device cannot maintain scheduled flows, there will be a historical allocation on the Flowgate based on parallel flows.

6.1.3 **Real-Time Operations Process.** The Parties' capabilities and real time actions shall be governed by and in accordance with the Congestion Management Process.

Section 6.2 Costs Arising From Reciprocal Coordination of Flowgates During Phase 2 and Phase 3. In the event redispatch occurs in order to coordinate congestion management under Section 6.1 or subparts thereof, during Phase 2, Market to Non-Market, including redispatch necessary to respect the other Party's flowgate, or during Phase 3, Market to Market, as set forth in Article XII, the Party responsible for the flow that required the redispatch shall bear the costs of the redispatch to the extent the costs may be recovered under the Party's OATT.

Section 6.3 Transmission Capacity for Reserve Sharing. Each Party shall make transmission capacity available for reserve sharing by either redispatching its flowgates or holding TRM for generation outages in the other Party's system. The Party responsible for making transmission capacity available for the reserve sharing obligation shall bear the costs of the redispatch to the extent the costs may be recovered under such Party's OATT.

ARTICLE VII
COORDINATION OF OUTAGES

Section 7.1 Coordinating Outages Operating Protocols. The Parties will jointly develop protocols for coordinating transmission and generation outages to ensure reliability and to promote optimally efficient market operations. The Parties agree to the following with respect to transmission and generation outage coordination.

Section 7.1.1 <u>Exchange of Transmission and Generation Outage Schedule Data</u>. Upon a Party's request, the projected status of generation and transmission availability will be communicated between the Parties, subject to data confidentiality agreements. All available information regardless of scheduled date will be shared. The Parties shall exchange the most current information on proposed outages and provide a timely response on anticipated impacts of proposed outages.

The Parties agree that this information will be shared promptly upon its availability, but no less than daily and more often as required by system conditions. The Parties shall jointly develop a common format for the exchange of this information. The information shall include the owning Party's facility name; proposed outage start date and time; proposed facility return date and time; date and time when a response is needed from the impacted Party to modify the proposed schedule; and any other information that may be relevant to the reliability assessment.

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

Section 7.1.2 <u>Evaluation and Coordination of Transmission and Generation Outages</u>. The Parties will analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each Party's outage analysis will consider the impact of its critical outages on the other Party's system reliability, in addition to its own.

On a daily basis, the operations planning staff of each Party shall jointly discuss any outages to identify potential impacts. These discussions should include an indication of either concurrence with the outage or identify significant impact due to the outage as scheduled. Neither Party has the authority to cancel the other Party's outage (except transmission facilities interconnecting the two Parties' transmission systems). However, the Parties will work together to resolve any identified outage conflicts. Consideration will be given to outage submittal times and outage criticality when addressing outage conflicts. If outage analysis indicates unacceptable system conditions, the Parties will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of proposed maintenance. If an operating procedure cannot be developed and a change to the proposed schedule is necessary based on significant impact, the Parties shall discuss the facts involved and make every effort to act on behalf of the other Party to effect the requested schedule change. If this change cannot be accommodated, the Party with the outage shall notify the impacted Party. A request to adjust a proposed outage date must include, identification of the facility(s) overloaded, and identify a similar time frame of more appropriate dates/times for the outage.

The Parties will notify each other of emergency maintenance and forced outages as soon as possible after these conditions are known (not to exceed thirty (30) minutes). The Parties will evaluate the impact of emergency and forced outages on the Parties' systems and work with one another to develop remedial steps as necessary.

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

ARTICLE VIII
JOINT OPERATION OF EMERGENCY PROCEDURES

Section 8.1 Emergency Operating Procedures. Joint emergency procedures are essential due to the highly dependent nature of facilities under different authorities. The Parties are committed to reliable operation of the transmission system under normal conditions, and will work closely together during emergency situations that place the stability of the transmission system in jeopardy.

In the event either Party declares a system emergency with respect to its system, the Parties will coordinate respective actions to provide immediate relief. The Parties will notify each other of emergency maintenance and forced outages as soon as possible after the conditions are known. The Parties will evaluate the impact of emergency and forced outages on the Parties' systems and work with one another to develop remedial steps as necessary

In the interest of maintaining system stability and providing prompt response to problems that may arise, the Parties agree that in situations where there is an actual Interconnected Reliability Limit ("IRL") violation and/or the system is on the verge of imminent collapse, and when there is already an existing Emergency Procedure or Operating Guide, both Parties and the affected operating entity will communicate and coordinate simultaneously via conference calls. Subsequent to such anomalous operations, the requesting Party will file a lessons learned report for the Parties and operating entities. This lesson learned report may assist in improving operations so that future operations will be more proactive; thereby, avoiding such abnormal communications/procedures.

The Parties will work together and with the Control Areas under their purview to jointly develop and commit to additional emergency procedures as the need for such procedures arises.

TLR Level 6 may be implemented when, in the judgment of either Party, the system is in an emergency condition that is characterized by the potential, either imminently or for the next contingency, for system instability or cascading, or for equipment loading or voltages significantly beyond applicable operating limits, such that stability of the system cannot be assured, or to prevent a condition or situation that in the judgment of a Party is imminently likely to endanger life or property. In the event that it becomes necessary for either Party to issue a TLR Level 6 for a flowgate that is in close electrical proximity to both of the Parties' areas, both Parties will take action(s) in kind to address the situation that prompted the TLR. These actions may include:

(a) Curtailment of equivalent amounts of firm point-to-point transactions within both Parties;

(b) Redispatching of generation within both Parties; and

(c) Load shedding within both Parties.

In situations where an actual IRL violation exists and the transmission system is currently, or for the next contingency would be, on the verge of imminent collapse, and there is not an existing Emergency Procedure or Operating Guide, the Parties will receive and carry out the instruction of the affected Party, or communicate the instruction to the affected entity within their own boundary, or utilize conference call capabilities to allow simultaneous coordination/communication between the Parties and the affected entity.

No delay shall take place during the event, except in instances where the requested action will result in a more serious condition on the transmission system, or instances where, in the judgment of either Party, the requested action is imminently likely to endanger life or property. Financial considerations shall have no bearing on actions taken to prevent the collapse of the transmission system. All occurrences of this kind may be reviewed by either or both Parties after the fact.

In a situation where a System Operating Limit ("SOL") violation exists within the regions of the Parties, or for the next contingency would exist, the Parties will work together as necessary, following good utility practices, and take action in kind as required to address the situation.

As the Reliability Coordinator for each respective region, each Party has the responsibility and authority to coordinate with the other Party and direct emergency action on the part of generation or transmission to protect the reliability of the network and shall do so if required to resolve emergency conditions in the other Party's region.

Section 8.1.1 Power System Restoration. Effective restoration procedures require coordination and communication at all levels of the Parties' organizations and their membership. During power system restoration, the Parties will coordinate their actions with each other, as well as with other Reliability Coordinators, in order to restore the transmission system as safely and efficiently as possible. In order to enhance restoration operations between the Parties, both Parties will conduct annual coordinated restoration drills. These drills will stress cooperation and communication so that both Parties are positioned to better assist the other in a real restoration

Section 8.1.2 Joint Voltage Stability Operating Protocol. Voltage stability or collapse problems have the potential to cause cascading outages and therefore must be closely coordinated to maintain reliable operations. The Parties were formed to have a regional perspective that looks beyond the boundary of a single control area. As such, the Parties will coordinate operations in accordance with good utility practice in order to maintain stable voltage profiles throughout the respective Party's zones of operations.

Section 8.1.3 Conservative Operations. When any one Party identifies an overload/emergency situation that may impact the other Party's system and the other Party's results/systems do not observe a similar situation, both Parties will operate to the most conservative result until the Parties can identify the reasons for these difference(s).

Section 8.2 Compensation for Compliance with Emergency Procedures. Each Party is to bear its own costs of compliance with emergency energy procedures, except as the applicable Tariff may otherwise require. If a Party is required to purchase emergency energy in order to address the flow of the other Party, then the other Party shall be required to provide compensation.

ARTICLE IX
COORDINATED REGIONAL TRANSMISSION EXPANSION PLANNING

Section 9.1 Committees.

Section 9.1.1 Joint Planning Committee. The Seams Agreement Coordinating Committee ("SACC") shall form, as a subcommittee, a Joint Planning Committee ("JPC"), comprised of representatives of the Parties' respective staffs in numbers and functions to be identified from time to time. Each Party shall have the right, every other year, to designate a Chairman of the JPC to serve a one-year calendar term, except that the term of the first Chairman shall commence on the Effective Date and end December 31, 2004. The SACC shall designate the first Chairman. The Chairman shall be responsible for the scheduling of meetings, the preparation of agendas for meetings, and the production of minutes of meetings. The JPC shall coordinate the coordinated system planning under this Agreement, including the following:

(a) Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed, the JPC shall develop common power system analysis models to perform coordinated systems planning, as well as models for power flow analyses, short circuit analyses, and stability analyses. For studies of interconnections in close electrical proximity at the boundaries between the systems of the Parties, the JPC will direct the performance of a detailed review of the appropriateness of applicable power system models.

(b) Prepare, on a regular basis, a Coordinated Systems Plan as required under Section 9.3.5.

(c) Coordinate all planning activities under this Article IX, including the exchange of data provided under this Article.

(d) Maintain and share the cost of maintaining an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process.

(e) Meet at least a semi-annually to review and coordinate transmission planning activities.

(f) Support the review by any federal or provincial agency of elements of the Coordinated System Plan.

(g) Support the review by multi-state entities to facilitate the addition of inter-state transmission facilities.

(h) Establish working groups as necessary to provide adequate review and development of the regional plans.

(i) Establish a schedule for the rotation of responsibility for data management, coordination of stakeholder meetings, coordination of analysis activities, report preparation, and other activities.

(j) Oversee an annual meeting of the Parties' system operations, market operations, and system planning personnel (such personnel as the Parties may designate for the meeting), to review the issues impacting the coordination of these functions as they impact long range planning and the coordination of planning between the systems.

Section 9.1.2 **Inter-regional Planning Stakeholder Advisory Committee.** The Parties shall form an Inter-regional Planning Stakeholder Advisory Committee ("IPSAC"). The IPSAC shall facilitate stakeholder review and input into coordinated system planning for the development of the Coordinated System Plan. IPSAC members shall be members of the

MIDWEST ISO Planning Advisory Committee, or its successor, and the SPP Operations Policy Committee, or its successor. Other stakeholders shall be permitted to become members, including stakeholders created by change of geographic scope. The IPSAC will meet no less frequently than prior to the start of each cycle of the coordinated planning process, during the development of the Coordinated System Plan, and upon completion of the Plan to review final results.

Section 9.2 Data and Information Exchange. In support of coordinated system planning, each Party shall provide the other with the following data and information. Unless otherwise indicated, such data and information shall be provided annually.

(a) Data required for the development of load flow cases, short-circuit cases, and stability cases, including ten year load forecasts, including all critical assumptions that are used in the development of these cases.

(b) Fully detailed planning models for a mutually agreeable set of seasons and years over a ten-year horizon. Updates to these cases are to be provided no less than quarterly.

(c) The regional plan document produced by the Party, any long-term or short-term reliability assessment documents produced by the Party, and any operating assessment reports produced by the Party.

(d) The status of expansion studies, system impact studies and generation interconnection studies, such that each Party has knowledge that a commitment has been made to a system enhancement as a result of any such studies.

(e) Transmission system maps for the Party's bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two systems.

(f) Contingency lists for use in load flow and stability analyses, including lists of all single contingency events and multiple facility tower line contingencies, as well as breaker diagrams for the portions of the Party's transmission system that are relevant to the coordination of planning between the two systems.

(g) The timing of each planned enhancement, including estimated completion dates and project mobilization schedules, and indications of the likelihood a system enhancement will be completed and whether the system enhancement should be included in system expansion studies, system impact studies and generation interconnection studies, and all related applications for regulatory approval and the status thereof. This information shall be provided annually and from time to time upon changes in status.

(h) Monthly identification of interconnection requests that have been received and any long-term firm transmission services that have been approved that may impact the operation of a Party's system in a manner that affects the other Party's system.

(i) Quarterly, the status of all interconnection requests that have been identified.

(j) Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between the systems.

(k) Such other data and information as is needed for each Party to plan its own system accurately and reliably and to assess the impact of conditions existing on the system of the other Party.

(l) Load flow and short-circuit data initially will be exchanged in PSS/E format. To the extent practical the maintenance and exchange of power system modeling data will be implemented through databases. When feasible, transmission maps and breaker diagrams will be provided in an electronic format agreed upon by the Parties. Formats for the exchange of other data will be agreed upon by the Parties from time to time.

Section 9.3 Coordinated System Planning. The primary purpose of coordinated transmission planning is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, or enhance the competitiveness of electricity markets.

Section 9.3.1 <u>Single Party Planning</u>. Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as are necessary to fulfill its obligations under its agreements and open access transmission tariff. Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, or any successor organizations, and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report and document the procedures, methodologies, and business rules that are utilized in preparing and completing this transmission planning report. The Parties further agree to share, on an ongoing basis, information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties, including, in addition to the information sharing requirements of Sections 9.2 and 9.3, the identification of proposed transmission system enhancements that may affect the Parties' respective systems.

Section 9.3.2 **Coordinated System Plan.** The Parties will coordinate any studies required to assure the reliable, efficient, and effective operation of the transmission system. Results of such coordinated studies will be included in the Coordinated System Plan. The Coordinated System Plan shall have as input the results of ongoing analyses of requests for interconnection and ongoing analyses of requests for long-term firm transmission service. The Parties shall coordinate in the analyses of these ongoing service requests in accordance with Sections 9.3.3 and 9.3.4. The Coordinated System Plan shall be an integral part of the expansion plans of each Party. Construction of upgrades that are identified as necessary in the Coordinated System Plan shall be under the terms of the Transmission Owner Agreements of the Parties, applicable to the construction of upgrades identified in the expansion planning process.

Section 9.3.3 **Analysis of Interconnection Requests.** In accordance with the procedures under which the Parties provide interconnection service, each Party will coordinate with the other the conduct of any studies required in determining the impact of a request for generator or merchant transmission interconnection. Results of such coordinated studies will be included in the impacts reported to the interconnection customers as appropriate. Coordination of studies and upgrades will include the following:

(a) Upon the posting to the OASIS of a request for interconnection, the Party receiving the request ("direct connect system") will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the directly connected system will notify the other Party and convey the information provided in the posting.

(b) If the potentially impacted Party determines that its system may be materially impacted by the interconnection, that Party will contact the direct connect system and request participation in the applicable interconnection studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the interconnection on the potentially impacted Party, who will perform the studies. The Parties will strive to minimize the costs associated with the coordinated study process.

(c) Any coordinated studies will be performed in accordance with the study timeline requirements of the applicable generation interconnection procedures of the direct connect system. The potentially impacted Party will comply with this schedule.

(d) The potentially impacted Party may participate in the coordinated study either by taking responsibility for performance of studies of its system, or by providing input to the studies to be performed by the direct connect system. The study cost estimates indicated in the study agreement between the direct connect system and the interconnection customer will reflect the costs and the associated roles of the study participants including the potentially impacted Party. The direct connect system will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(e) The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts to the potentially impacted Party.

(f) If the results of the coordinated study indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the direct connect system will identify the need for such network upgrades in the system impact study prepared for the interconnection customer.

(g) Requirements for construction of such Network Upgrades will be under the terms of the applicable OATT, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

(h) Each Party will maintain a separate interconnection queue. The JPC will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of both Parties. The JPC will post this listing on the Internet site maintained for the communication of information related to the coordinated planning process. The Internet site will contain links to the web sites of each Party where individual interconnection study results will be maintained.

Section 9.3.4 <u>Analysis of Long Term Firm Transmission Service Requests</u>. In accordance with applicable procedures under which the Parties provide long-term firm transmission service, the Parties will coordinate the conduct of any studies required to determine the impact of a request for such service. Results of such coordinated studies will be included in the impacts reported to the transmission service customers as appropriate. Coordination of studies will include the following:

(a) The Parties will coordinate the calculation of ATC values associated with the service, based on contingencies on the systems of each Party that may be impacted by the granting of the service.

(b) Upon the posting to the OASIS of a request for service, the Party receiving the request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the request will notify the other Party and convey the information provided in the posting.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, that Party will contact the Party receiving the request and request participation in the applicable transmission service studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party, who will perform the studies. The Parties will strive to maximize the cost efficiency of the coordinated study process. The JPC will develop screening procedures to assist in the identification of service requests that may impact systems of parties other than the system receiving the request.

(d) Any coordinated studies will be performed in accordance with the study timeline requirements of the applicable transmission service procedures of the Party receiving the request. The potentially impacted Party will comply with this schedule.

(e) The potentially impacted system may participate in the coordinated study either by taking responsibility for performance of studies of their system, or by providing input to the studies to be performed by the Party receiving the request. The study cost estimates indicated in the study agreement between the Party receiving the request and the transmission service customer will reflect the costs and the associated roles of the study participants. The Party receiving the request will review the cost estimates submitted by all participants for reasonableness, based on expected level of participation and responsibilities in the study.

(f) The Party receiving the request will collect from the transmission service customer and forward to the potentially impacted system the costs incurred by the potentially impacted systems associated with the performance of such studies.

(g) If the results of a coordinated study indicate that network upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the potentially impacted system, the system receiving the request will identify the need for such network upgrades in the system impact study prepared for the transmission service customer.

(h) Requirements for the construction of such Network Upgrades will be under the terms of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state, or provincial regulatory policy.

Section 9.3.5 <u>Development of the Coordinated System Plan</u>. Each Party agrees to assist in the preparation of a Coordinated System Plan applicable to the Parties' systems. Each Party's annual transmission planning reports will be incorporated into the Coordinated System Plan, however, neither Party shall have the right to veto any planning of the other Party nor shall either Party have the right, under this Article, to obtain financial compensation due to the impact of another Party's plans or additions. The IPSAC will have an opportunity to review and comment before the Coordinated System Plan is finalized:

(a) Integrate the Parties' respective transmission expansion plans, including any market-based additions to system infrastructure (such as generation or merchant transmission projects) and transmission system upgrades identified jointly by the Parties, together with alternatives to upgrades that were considered.

(b) Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to such system additions or upgrades; and

(c) Describe results of the analysis for the combined transmission systems, as well as the procedures, methodologies, and business rules that were utilized in preparing and completing the joint transmission analysis.

Coordination of studies required for the development of the Coordinated System Plan will include the following steps:

(a) Every three years, the Parties shall perform a comprehensive, coordinated regional transmission expansion planning study. Sensitivity analyses will be performed, as required, during the off years based on a review by the JPC and IPSAC of discrete reliability problems or operability issues that arise due to changing system conditions. Ad hoc study groups may be formed as needed to address localized seams issues identified.

(b) Each Party will be responsible for providing the technical support required to complete the analysis for the study. The responsibility for the coordinated study and the compilation of the coordinated study report will alternate between the Parties.

(c) The JPC will develop a scope and procedure for the inter-regional planning assessment. The scope of the study will include evaluations of the transmission system against the reliability criteria, operational performance criteria, and economic performance criteria applicable to each Party. Each Party will provide a baseline model that includes all transmission enhancements included in the party's regional transmission expansion plan, and all of the committed interconnection projects and any associated transmission upgrades.

(d) The Parties will use planning models that are developed in accordance with the procedures to be established by the JPC. Exchange of power flow models will be in a format that is acceptable to both Parties and will use a consistent bus numbering convention and bus naming convention to minimize work that is needed to merge detailed power flow models.

(e) The study will initially evaluate the reliability of the combined transmission systems. Any upgrades required to resolve criteria violations will be agreed upon and included in an updated baseline model.

(f) The performance of the combined transmission systems will be tested against agreed upon operational and economic criteria, where applicable, using the updated baseline model. Upgrades required to resolve operational and/or economic performance criteria violations will be included in the Coordinated System Plan.

(g) Economic criteria applicable to either Party will be developed and filed by that Party with input from its stakeholders.

Section 9.4 Allocation of Costs of Network Upgrades. "Affected System" shall mean the electric system of the Party other than the Party to which a request for interconnection or long-term firm delivery service is made and that may be affected by the proposed service.

Section 9.4.1 <u>Network Upgrades Associated with Interconnections</u>. When under Section 9.3.3, it is determined that a generation or merchant transmission interconnection to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the Parties' Order No. 2003 compliance filings as accepted by the FERC.

Section 9.4.2 Network Upgrades Associated with Transmission Service Requests. When under Section 9.3.4, it is determined that the granting of a long-term firm delivery service request with respect to a Party's system will have an impact on the Affected System such that Network Upgrades shall be made, the upgrades on the Affected System shall be paid for in accordance with the terms and conditions of the OATTs, agreement among owners of transmission facilities subject to the control of the potentially impacted Party and consistent with applicable federal, state or provincial regulatory policy.

Section 9.4.3 Network Upgrades Under Coordinated System Plan. Cost responsibility for the transmission upgrades identified in the Coordinated System Plan to resolve thermal or reactive system constraints related to reliability criteria or operational or economic system performance will be assigned to the Parties equitably, based on the nature of the constraint being resolved.

The JPC will develop procedures for evaluating, on a case-by-case basis, the relative contribution of the Party's systems to the constraint and the relative benefits derived by the parties by the resolution of the constraint. The JPC will propose an allocation of costs for such transmission system upgrades. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities. Stakeholder input will be taken into consideration by the JPC in arriving at a consensus allocation of costs. Upgrade proposals and cost allocations are subject to the approval process of both Parties for transmission upgrades. Each Party's allocation and the recovery of the costs of such Network Upgrades shall be consistent with the terms and conditions of its own OATT, as it may be modified from time to time pursuant to the rights of various parties under the Federal Power Act.

Section 9.5 Agreement to Enforce Duties to Construct and Own. To obtain Network Upgrades under this Article IX, SPP will enforce obligations to construct and own or finance enhancements or additions to transmission facilities in accordance with the SPP Membership Agreement and the SPP OATT, as both may be amended or restated from time to time, and MIDWEST ISO will enforce obligations to construct enhancements or additions to transmission facilities in accordance with the Agreement of Transmission Facilities Owners To Organize The Midwest Independent Transmission System Operator, Inc., A Delaware Non-Stock Corporation, Midwest ISO FERC Electric Tariff, First Revised Rate Schedule No. 1, as it may be amended or restated from time to time.

ARTICLE X
JOINT CHECKOUT PROCEDURES

Section 10.1 Scheduling Checkout Protocols.

Section 10.1.1 <u>Scheduling Protocols</u>. The Parties agree that each Party will leverage technology, where feasible, to perform electronic approvals of schedules and to perform electronic checkouts, in lieu of telephone calls. The Parties agree to follow the following scheduling protocols:

Section 10.1.1.1 Each Party, acting as the scheduling agent for their respective Control Areas, will conduct all checkouts with their first tier Control Areas or the scheduling agent acting on behalf of those first-tier Control Areas. A first tier Control Area is any Control Area that is directly connected to any Party's members' Control Area.

Section 10.1.1.2 The Parties will require all schedules between the Parties, other than reserve sharing or other emergency events and loss payback schedules, to be tagged via the NERC tagging standard. For reserve sharing and other emergency schedules that are not tagged, the Parties will enter manual schedules after the fact into their respective scheduling systems to facilitate checkout between the Parties.

Section 10.1.1.3 When there is a scheduling conflict, the Parties will work in unison to modify the schedule as soon as practical. If there is a scheduling conflict that is identified before the schedule has started, then both Parties will make the correction in real-time and not wait until the quarter hour. If the schedule has already started and one Party identifies an error, then the Parties will make the correction at the earliest quarter hour increment. If a scheduling conflict cannot be resolved between the Parties (but the source and sink have agreed to a MW value), then the Parties will both adjust their numbers to that same MW value. If source and sink are unable to agree to a MW value, then the previously tagged value will stand for both Parties.

Section 10.1.1.4 For Control Areas or associated scheduling agents that do not use the respective Parties' electronic scheduling interfaces, the Parties will contact those entities by telephone to perform checkouts.

Section 10.1.1.5 The Parties will perform the following types of checkouts:

(a) Pre-schedule (Day-Ahead) daily between 1800 and 2200 hours;
- Intra-hour checkout/schedule confirmation will occur as required due to intra-hour scheduled changes.

(b) Hourly Before the Fact (Real-Time);
- Hourly before the fact checkout includes the verification of import and export totals in addition to net scheduled interchange ("NSI") for control areas with that ability. At a future time, the Parties may checkout individual schedules.
- Hourly checkout is performed starting at the half hour and ending at the ramp hour.

(c) After the Fact (Day End) daily starting at 0100 hours; and

(d) After the Fact (Monthly) daily on a month to date basis (usually via email) starting on the first business day of the month and ending by the tenth (10^{th}) business day of that following month.

Section 10.1.1.6 The Parties will require that each of these checkouts be performed with first tier Control Areas. If a checkout discrepancy is discovered, the Parties will use the NERC tag to find where the discrepancy exists. The Parties will require any entity that conducts business within its region to checkout with the Parties using NERC tag numbers; special naming convention used by that entity or other naming conventions given to schedules by other entities will not be permitted.

ARTICLE XI
VOLTAGE CONTROL AND REACTIVE POWER COORDINATION

11.1 Coordination Objectives. Each Party acknowledges that voltage control and reactive power coordination are essential to promote reliability. Therefore, the Parties establish procedures ("Voltage and Reactive Power Coordination Procedures") under this Article by which they shall conduct such coordination.

11.1.1 The Voltage and Reactive Power Coordination Procedures address the following components: (a) procedures to assist the Parties in maintaining a wide area view of interconnection conditions by enhancing the coordination of voltage and reactive levels throughout their RTO footprints; (b) procedures to ensure the maintenance of sufficient reactive reserves to respond to scenarios of high load periods, loss of critical reactive resources, and unusually high transfers; and (c) procedures for sharing of data with other neighboring Reliability Coordinators for their analysis and coordinated operation.

11.1.2 The Parties will review the Voltage and Reactive Power Coordination Procedures from time to time to make revisions and enhancements as appropriate to accommodate additional capabilities or changes to industry reliability requirements.

Section 11.2 Voltage and Reactive Power Coordination Procedures. The Parties will utilize the following procedures to coordinate the use of voltage control equipment to maintain a reliable bulk power transmission system voltage profile on their respective systems.

11.2.1 Under normal conditions, each Party will coordinate with the owners of the transmission facilities subject to its control and the Control Areas as necessary and feasible to supply its own reactive load and losses at all load levels.

11.2.2 Voltage schedule coordination is the responsibility of each Party. Generally, the voltage schedule is determined based on conditions in the proximity of generating stations and Extra High Voltage ("EHV") (defined as 230 KV facilities and above) stations with voltage regulating capabilities. Each Party works with its respective owners of transmission facilities and Control Areas to determine adequate and reliable voltage schedules considering actual and post-contingency conditions.

11.2.3 Each Party will establish voltage limits at critical locations within its own system and exchange this information with the other Party. This information shall include normal high voltage limits, normal low voltage limits, post-contingency emergency high voltage limits and post-contingency emergency low voltage limits, and, shall identify the voltage limit value (if available) at which load shedding will be implemented.

11.2.4 Each Party will maintain awareness of the voltage limits in the other Party's area (where the EMS Model includes sufficient detail to permit this) and awareness of outages and potential contingencies that could result in violation of those voltage limits.

11.2.5 The Parties will clearly communicate the level of voltage support needed during pre- or post-contingency conditions requiring voltage and reactive power coordination.

11.2.6 Each Party shall maintain a list of actions that are available to be taken when voltage support is necessary to respond to anticipated or prevailing system conditions.

11.2.7 Each calendar quarter the Parties will exchange voltage schedules and shall meet and confer to identify system conditions that could impact the schedules and determine adjustments to the schedules as are consistent with reliability.

11.2.8 In concert with the coordination of Outages addressed in Article VII and the Parties' respective day-ahead reliability analysis processes, the Parties will coordinate the impact of outages and system conditions on the voltage/reactive profile. Coordination will include the following elements:

11.2.8.1 Each Party will review its forecasted loads, transfers, and all information on available generation and transmission reactive power sources at the beginning of each shift.

11.2.8.2 If no reactive problems are anticipated after the review, each Party will operate independently in accordance with the above stated criteria and any individual system guidelines for the supply of the Party's reactive power requirements.

11.2.8.3 If either Party anticipates reactive problems after the review, it may request joint implementation of reactive support levels under these Voltage and Reactive Power Coordination Procedures, as it deems appropriate to the situation. When a Party calls for a particular level of support to be implemented under these procedures, it or the applicable Control Area must identify the time it will start adjusting its system, the support level it is implementing, and the voltage problem area.

11.2.8.4 If a Party experiences an actual low or high voltage condition after initial reactive support measures are taken, then the emergency reactive support level is implemented for the area experiencing the problem. The Party will also notify applicable Reliability Coordinators as soon as feasible. In addition, the Voltage and Reactive Power Coordination Procedures are to be consulted to determine if further action is necessary to correct an undesirable voltage situation.

11.2.9 The Parties will coordinate the use of voltage control equipment to maintain a reliable bulk power transmission system voltage profile on the SPP, MIDWEST ISO, and surrounding systems. The following procedures are intended to ensure that bulk systems voltage levels enhance system reliability.

11.2.9.1 Specific Voltage Schedule Coordination Actions.

(a) Each Party has operational or functional control of reactive sources within its system and will direct adjustments to voltage schedules at appropriate facilities.

(b) Each Party generally will adjust its voltage schedules to best utilize its resources for operation.

(c) If a Party anticipates voltage or reactive problems, it will inform the other Party (operations planning with respect to future day and Reliability Coordinator with respect to same day) of the situation, describe the conditions, and request voltage/reactive support under these Procedures. As a part of the request, the Party must identify the specific area where voltage/reactive support is requested and provide an estimate of the magnitude and time duration of the request as well as the specific voltage and limit.

(d) The requesting Party will arrange a conference call between the affected Control Areas/transmission owners and the Parties. The purpose of this call is to ensure that the situation is fully understood and that an effective operating plan to address the situation has been developed.

(e) Each Party will implement or direct voltage schedule changes requested by the other Party, provided that a Party may decline a requested change if the change would result in equipment violations or reduce the effective operation of its facilities. A Party that declines a requested change must inform the requesting Party that the request cannot be granted and state the reason for denial.

11.2.10 Voltage/Reactive Transfer Limits.

11.2.10.1 Each Party may monitor power transfer on interfaces defined as a Flowgate used to control voltage collapse conditions. In cases where the potential for voltage collapse (or cascading) is identified, prompt voltage support and generation adjustments are needed. Generation adjustment requests to avoid voltage collapse or cascading conditions must be clearly communicated and implemented promptly. Using these limits the Parties will implement the following real-time coordination:

(a) At 95% of Interface Limit

- A Party, which observes the reading shall call the other Party to discuss whether further analysis is required.
- The Party owning the Flowgate will notify other Reliability Coordinators via the reliability coordinator information system (RCIS).
- The Parties will conduct a conference call with the affected Control Areas to discuss reactive outputs and/or capabilities.
- The applicable Party takes appropriate actions, which may include re-dispatching generation and directing schedule curtailments.

(b) Exceeding Interface Limit

- The Party owning the Flowgate will declare an emergency and inform other Reliability Coordinators of the emergency.
- The applicable Party will take immediate action, which may include generation redispatch, ordering immediate schedule curtailments, and, if required, load shedding.

11.2.10.2 Where feasible, and if both Parties' EMS models have sufficient detail, each Party will attempt to duplicate the other Party's power transfer evaluation in order to provide backup limit calculation in the event that the primary Party is unable to accurately determine the appropriate reliability limits.

11.2.10.3 If a new power transfer interface is determined to exist and detailed modeling does not exist for the interface, the Parties will coordinate to determine how their models need to be enhanced and to determine procedures for coordination in furtherance of the enhancement.

ARTICLE XII
ADDITIONAL COORDINATION PROVISIONS

Section 12.1 Application of Congestion Management Process. The Parties have agreed to certain operating 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 applicable NERC reliability plans. As addressed in Section 3.1, the Parties expect that these systems and the operating protocols applicable to these systems will change and revisions of this Agreement will be required from time to time.

Section 12.2 Operating Objectives, Changes. The Parties have agreed to certain operating protocols under this Agreement to ensure system reliability and efficient market operations as systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and the operating protocols applicable to these systems will change upon the startup of Phase 3, Market to Market implementation. 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 requirements and protocols. Prior to the initiation of Phase 3, the Parties will develop a Phase 3 White Paper containing protocols to achieve the following objectives:

Section 12.3 Additional Provisions Concerning Phase 3, Market to Market.

Section 12.3.1 <u>Calculation Consistency</u>. The Parties' goal will be that the energy prices calculated by both Parties for relevant interfaces between their respective markets are coordinated and consistent. Therefore, to the extent that such prices are not identical, the Parties agree to work in good faith to send the most consistent economic signal possible to all market participants.

Section 12.3.2 <u>Overview of the Market-to-Market Coordination Process</u>. The fundamental philosophy of the Market-to-Market transmission congestion coordination process is to allow any transmission constraints that are significantly impacted by generation dispatch changes in both markets to be jointly managed in the security-constrained economic dispatch models of both Parties. This joint management of transmission constraints near the market borders will provide the most efficient and least costly transmission congestion management and will also provide coordinated pricing at the market boundaries.

This Market-to-Market coordination process should build upon the Parties' Market to Non-market coordination process as a starting point. Before the implementation of Phase 2, the Parties will have agreed upon the inter-regional coordination process between a market region and a non-market region (*i.e.* a market to non-market interface). The set of transmission flowgates in each market that can be significantly impacted by the economic dispatch of generation serving load in the adjacent market will be identified by the Parties. These flowgates will then be monitored to measure the impact of market flows and loop flows from adjacent regions. The procedures developed by the Parties will provide a framework for calculating the resulting powerflow impacts resulting from the market-based economic dispatch in one region on the transmission facilities in an adjacent region and vice versa. In addition, the Parties will have reached agreement on how the market flow impacts will be managed on an interregional basis within the existing NERC IDC to enhance the effectiveness of the NERC interregional congestion management process. Lastly, the Parties agree that flow entitlement for Network and Firm transmission utilization in one region has an impact on the transmission facilities in an adjacent region.

The Market-to-Market coordination process builds on the work already completed as described above because of the continuing requirement to coordinate with adjacent regions even after the Parties' markets are implemented.

Section 12.3.3 Identification of Transmission Constraints that Require Coordinated Transmission Congestion Management. Only a subset of all transmission constraints that exist in either market will require coordinated congestion management. This subset of transmission constraints will be identified in a manner similar to the method described above. The list of transmission constraints will be limited to only those for which at least one generator in the adjacent market has a significant power distribution factor, as agreed upon by the Parties, with respect to serving load in the adjacent region.

Section 12.3.4 Real-time Market Coordination. The Parties will explore joint methods to relieve the other Party's binding constraint(s) in real-time.

Section 12.3.5 Coordination of Interregional Transactions (via Proxy Buses). In order for the Market-to-Market coordination to function properly, the proxy bus models for the Parties must be coordinated to the same level of granularity. The proxy bus modeling approaches should be consistent at the market borders.

Section 12.3.6 Evolution of the Market-to-Market Coordination Process. Nothing in this Agreement will preclude the Parties from further evolving their market coordination process in conjunction with input from their respective market monitors.

Section 12.3.7 Coordinated Emergency Generation Redispatch. The Parties shall follow a security constrained, least-cost dispatch protocol in response to system emergencies, and the costs thereof shall be reflected in, and compensated through, relative energy prices values. However, in the event that costs not cognizable under energy prices are incurred, the Party within which the affected resources are located shall reimburse such resource for direct incremental cost, subject to inter-Party reimbursement in the event that the costs incurred by one Party were caused by a system emergency in the other Party.

Additionally, in the absence of the need to coordinate congestion or address a system emergency, a Party shall be entitled to request that the other Party dispatch a generation unit, subject to the Parties' agreement with respect to compensation for the dispatch.

Section 12.3.8 Joint Reliability Coordination.

Section 12.3.8.1 Introduction. The Parties will explore and develop market procedures to be used in emergency conditions. The procedures shall be used solely when, in the exercise of Good Utility Practice, a Party determines that the redispatch of generation units on the other Party's transmission system would reduce or eliminate the need to resort to Transmission Loading Relief or other transmission-related emergency procedures.

Section 12.3.8.2 Identification of Transmission Constraints.

(a) On a periodic basis determined by the Parties, the Parties shall identify potential transmission operating constraints that could result in the need to use Transmission Loading Relief or other emergency procedures in order to alleviate the transmission constraints, the need for which could be reduced or eliminated by the redispatch of generation on the other's system.

(b) In addition to the identification of such potential transmission operating constraints, the Parties shall each identify generation units on the other Party's system, the redispatch of which would alleviate the identified transmission constraints.

(c) From the identified transmission constraints, the Parties shall agree in writing on the transmission operating constraints and redispatch options that shall be subject to this Section until otherwise agreed. In reaching such agreement, the Parties shall endeavor reasonably to limit the number of transmission constraints that are subject to this Section so as to minimize potential cost shifting among market participants in the control areas of the Parties resulting from the redispatch of generation under this Section. Both Parties shall post the transmission operating constraints that are subject to this Section on their respective Internet sites.

Section 12.3.8.3 Redispatch Procedures. If (i) a transmission constraint subject to this Section 12 occurs and continues or reasonably can be expected to continue after the exhaustion of all economic alternatives that are reasonably available to the transmission system on which the constraint occurs and (ii) the MIDWEST ISO or SPP, as applicable, has determined that it must either use Transmission Loading Relief or other emergency procedures, then (iii) the affected entity may request the other to redispatch one or more of the previously identified generation units to alleviate the transmission constraints. Upon such request, the MIDWEST ISO or SPP, as applicable, shall redispatch such generation if it is then subject to its dispatch control and such redispatch is consistent with good utility practice.

Section 12.3.9 Equitable Compensation for Generation Redispatch. Prior to the implementation of Phase 3, the Parties agree to develop a methodology to compensate a Party that redispatches generation at the request of the other Party in order to relieve a congestion constraint.

ARTICLE XIII
EFFECTIVE DATE

Section 13.1 The Parties agree to file this Agreement jointly with FERC on or before December 1, 2004 and to cooperate with each other as necessary and appropriate to facilitate such filing. In that filing, the Parties shall request FERC to approve an effective date of December 1, 2004 (“Effective Date” is the date specified by the FERC).

ARTICLE XIV
COOPERATION AND DISPUTE RESOLUTION PROCEDURES

Section 14.1 Administration of Agreement. The SACC established under the Memorandum of Understanding, shall perform the following with respect to this Agreement:

(a) Meet no less than once annually to determine whether changes to this Agreement would enhance reliability, efficiency, or economy and to address other matters concerning this Agreement as either Party may raise.

(b) Conduct additional meetings upon Notice given by either Party, provided that the Notice specifies the reason for the requested meeting.

(c) Establish task forces and working committees as appropriate to address any issues a Party may raise in furtherance of the objectives of this Agreement.

(d) Conduct dispute resolution in accordance with this Article.

(e) Initiate process reviews at the request of either Party for activities undertaken in the performance of this Agreement.

The SACC shall have the authority to make decisions on issues that arise during the performance of the Agreement based upon consensus of the Parties' representatives thereto.

Section 14.2 Dispute Resolution Procedures. The Parties shall attempt in good faith to achieve consensus with respect to all matters arising under this Agreement and to use reasonable efforts through good faith discussion and negotiation to avoid and resolve disputes that could delay or impede either Party from receiving the benefits of this Agreement. These dispute resolution procedures apply to any dispute that arises from either Party's performance of, or failure to perform, this Agreement and which the Parties are unable to resolve prior to invocation of these procedures.

Section 14.2.1 Step One. In the event a dispute arises, a Party shall give written notice of the dispute to the other Party. Within ten (10) days of such Notice, the SACC shall meet and the Parties will attempt to resolve the Dispute by reasonable efforts through good faith discussion and negotiation. Each Party shall also be permitted to bring no more than two (2) other individuals to Executive Committee meetings as subject matter experts; however, all representatives must be employees of the Party they represent. In addition, if the Parties agree that legal representation would be useful in connection with a meeting, each Party may bring two (2) attorneys (who need not be employees of the Party they represent). In the event the SACC is unable to resolve within twenty (20) days of such Notice, either Party shall be entitled to invoke Step 2.

Section 14.2.2 Step Two. A Party may invoke Step 2 by giving Notice thereof to the SACC. In the event a Party invokes Step 2, the SACC shall, in writing, and no later than five (5) days after the Notice, refer the dispute in writing to the Parties' Presidents for consideration. The Parties' Presidents shall meet in person no later than fourteen (14) days after such referral and shall make a good faith effort to resolve the dispute. The Parties shall serve upon each other, written position papers concerning the dispute, no later than forty-eight (48) hours in advance of such meeting. In the event the Parties' Presidents fail to resolve the dispute, either Party shall be entitled to invoke Step Three.

Section 14.2.3 Step Three. Upon the demand of either Party, the dispute shall be referred to FERC's Office of Dispute Resolution for mediation, and upon a Party's determination at any point in the mediation that mediation has failed to resolve the dispute, either Party may seek formal resolution by initiating a proceeding before FERC.

Section 14.2.4 **Exceptions.** In the event of disputes involving Confidential Information, infringement or ownership of Intellectual Property or rights pertaining thereto, or any dispute where a Party seeks temporary or preliminary injunctive relief to avoid alleged immediate and irreparable harm, the procedures stated in Section 14.2 and its subparts shall apply but shall not preclude a Party from seeking such temporary or preliminary injunctive relief, provided, that if a Party seeks such judicial relief but fails to obtain it, the Party seeking such relief shall pay the reasonable attorneys' fees and costs of the other Party incurred with respect to opposing such relief.

ARTICLE XV
RELATIONSHIP OF THE PARTIES

Section 15.1 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 prior to the creation of a functioning Market by one or both of the Parties. Specifically, Articles III through XII 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 address further protocols that may be required to facilitate each Party's efforts to administer its respective markets.

ARTICLE XVI
ACCOUNTING AND ALLOCATION OF COSTS OF JOINT OPERATIONS

Section 16.1 Revenue Distribution. This Agreement does not modify any prior agreement with either Party's Transmission Owners with regard to revenue distribution. All distribution of revenue received under this agreement shall be distributed by the party receiving such revenue in accordance with the terms of such party's prior agreement with their Transmission Owners.

Section 16.2 Billing and Invoicing Procedures. Each Party shall render invoices to the other Party for amounts due under this Agreement in accordance with its customary billing practices and payment shall be due in accordance with the invoicing Party's customary payment requirements. All payments shall be made in immediately available funds payable to the invoicing Party 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 methodology specified for interest on refunds in the Commission's regulations at 18 C.F.R. § 35.19a(a)(2)(iii).

Section 16.3 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 verify the accuracy of charges between the Parties 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 XVII
RETAINED RIGHTS OF PARTIES

Section 17.1 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 independent 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 subject to and performed in a manner that complies with each Party's internal requirements; provided, however, this sentence shall not limit either Party's payment obligation under Article XVI or indemnity obligation under Section 18.3.1 or Section 18.3.2, respectively.

Section 17.2 Agreement to Jointly Make Required Tariff Changes to Implement Agreement. The Parties agree that they shall cooperate in good faith in the filing of any Section 205 filings before FERC that may be required to implement the terms of this Agreement to facilitate the Effective Date. Whenever practicable, the Parties agree that they shall make simultaneous filings with FERC concerning such Tariff filings.

ARTICLE XVIII
ADDITIONAL PROVISIONS

Section 18.1 Confidentiality.

Section 18.1.1 <u>Meaning</u>. 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" or which under all of the circumstances should be treated as 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 Confidential Information; 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.

Section 18.1.2 <u>Protection</u>. 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. This obligation of confidentiality shall not extend to information that, at no fault of the recipient

Party, is or was (1) in the public domain or generally available or known to the public; (2) disclosed to a recipient by a third party who had a legal right to do so; (3) independently developed by a Party or known to such Party prior to its disclosure hereunder; and (4) which is required to be disclosed by subpoena, law or other directive or a court, administrative agency or arbitration panel, in which 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.

Section 18.2 Protection of Intellectual Property.

(a) All Intellectual Property (as defined below), and modifications to, and enhancements of, and derivatives of such 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.

(c) For purposes of this Agreement:

- "Intellectual Property" means all patent rights (including patent applications, disclosures and Inventions (as defined below), rights of priority, mask work rights, copyrights, moral rights, trade secrets, know-how and any other intellectual property rights recognized in any country or jurisdiction of the world including trademarks, trade names, logos, service marks, and other designations of source; and
- "Inventions" means any idea, design, concept, technique, method, discovery or improvement conceived of and actually or constructively can be reduced to practice for which a patent application is or may be filed in the United States or in any foreign country, or for which a patent has issued in the United States or in any foreign country.

Section 18.3 Indemnity.

Section 18.3.1 <u>Indemnity of MIDWEST ISO</u>. SPP will defend, indemnify and hold the MIDWEST ISO harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against the Midwest ISO, only to the extent such Losses arise directly from:

(a) gross negligence, recklessness, or willful misconduct of SPP or any of SPP's agents or employees, on 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 MIDWEST ISO or any of the MIDWEST ISO's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon the MIDWEST ISO or the MIDWEST ISO's agents or employees;

(b) Any claim that the MIDWEST ISO 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 18.2.; and

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

Section 18.3.2 <u>Indemnity of SPP</u>. The MIDWEST ISO will defend, indemnify and hold SPP harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively "Losses"), brought or obtained by third parties against SPP, only to the extent such Losses arise directly from:

(a) gross negligence or recklessness, or willful misconduct of MIDWEST ISO or any of MIDWEST ISO'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 SPP or any of SPP's agents or employees, or (ii) as a consequence of strict liability imposed as a matter of law upon SPP or SPP's agents or employees;

(b) Any claim that SPP 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 18.2.; and

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

Section 18.3.3 Damages Limitation.

Section 18.3.3.1 Except for amounts agreed to be paid under Article XVI by one Party to the other under 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 this Agreement, unless such failure to perform was malicious or reckless.

Section 18.3.3.2 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.

Section 18.4 Effective Date and Termination Provision. The term of this Agreement commences upon its acceptance or approval by FERC. The Agreement shall terminate and cease to be effective upon FERC acceptance of the mutual agreement by the Parties to terminate the Agreement or other FERC order terminating the Agreement. Nothing in this Agreement shall prejudice the right of either Party to seek termination of this Agreement under Section 206 of the Federal Power Act, or successor section or statute thereof. Both Parties have committed to develop or to make significant software modifications that will require a reasonable time to implement, to fully realize the benefits of each Phase of this Agreement and the Congestion Management Process. It is mutually agreed that a Party will not be in breach of this Agreement if such development or modifications are not completed before the initiation of Phase 2 or Phase 3, if that Party is deemed to be making good faith, satisfactory progress toward implementing the required software on a reasonable schedule. Any dispute on the reasonableness of the software implementation schedule will be subject to Article XIV.

Section 18.5 Survival Provisions. Upon termination or expiration of this Agreement for any reason or in accordance with its terms, the following Articles and Sections shall be deemed to have survived such termination or expiration:

Article II - (Definitions and Rules of Construction)
Article XVI - (Accounting and Allocation of Costs of Joint Operations)
Article XVII- (Retained Rights of the Parties)
Article XVIII- (Additional Provisions), except Section 18.11 (Execution of Counterparts) and Section 18.12 (Amendment)

Section 18.6 No Third-Party Beneficiaries. 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 or benefits on, any third party (other than the Parties' successors and permitted assigns).

Section 18.7 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.

Section 18.8 *Force Majeure.* No Party shall be in breach of this Agreement to the extent and during the period such Party's performance is made impracticable by any unanticipated cause or causes beyond such Party's control and without such Party's fault or negligence, which may include, but are not limited to, any act, omission, or circumstance occasioned by or in consequence of any act of God, labor disturbance, act of the public enemy, 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 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.

Section 18.9 Governing Law. This Agreement shall be interpreted, construed and governed by the applicable federal law and the laws of the state of Delaware without giving effect to its conflict of law principles.

Section 18.10 Notice. Whether expressly so stated or not, all notices, demands, requests and other communications required or permitted by or provided for in this Agreement ("Notice") 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:

Southwest Power Pool, Inc.
415 North McKinley, #800 Plaza West
Little Rock, AR 72205-3020
Attention: General Counsel

Midwest Independent Transmission System Operator, Inc.
701 City Center Drive
Carmel, Indiana 46032
Attention: General Counsel

Section 18.11 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.

Section 18.12 Amendment. Except as may otherwise be provided herein, neither this Agreement nor any of the terms hereof may be amended unless such amendment is in writing and signed by the Parties and such amendment has been accepted by FERC.

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

Southwest Power Pool, Inc.

By: ______________________
Name: Nicholas A. Brown
Title: President and CEO

Date: December 1, 2004

Midwest Independent Transmission System Operator, Inc.

By: ______________________
Name: James P. Torgerson
Title: President and CEO

Date: December 1, 2004