Joint Operating Agreement

Between the

Midcontinent Independent System Operator, Inc.

And

PJM Interconnection, L.L.C.

(December 11, 2008)

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ARTICLE I
RECITALS

This Joint Operating Agreement ("Agreement") dated this 31st day of December, 2003, by and between PJM Interconnection, L.L.C. ("PJM") a Delaware limited liability company having a place of business at 2750 Monroe Blvd., Audubon, Pennsylvania 19403, and the Midcontinent Independent System Operator, Inc. ("MISO"), a Delaware non-stock corporation having a place of business at 720 City Center Drive, Carmel, Indiana 46032.

WHEREAS, PJM is the regional transmission organization that provides operating and reliability functions in portions of the mid-Atlantic and Midwest States. PJM also administers an open access tariff for transmission and related services on its grid, and independently operates markets for day-ahead, real-time energy, and financially firm transmission rights;

WHEREAS, MISO is the regional transmission organization that provides operating and reliability functions in portions of the Midwest States and Canadian Provinces. MISO administers an open access tariff for transmission and related services on its grid, and is developing processes and systems to operate markets to facilitate trading of day-ahead, real-time energy, and financially firm transmission rights;

WHEREAS, the Federal Energy Regulatory Commission has ordered each regional transmission organization to develop mechanisms to address inter-regional coordination;

WHEREAS, on February 12, 2003, the Parties entered into the Agreement Concerning Inter-regional Coordination, Including Development of Joint and Common Market ("Joint and Common Market Agreement"), which provides for the establishment of an Inter-RTO Steering Committee to facilitate development of the Joint and Common Market and resolution of seams issues between the Parties;

WHEREAS, certain other electric utilities will be integrated into the systems and markets PJM administers and controls, and it is recognized that such integration may result in changed flows on the systems of PJM and MISO as they exist prior to such integration;

WHEREAS, in accordance with good utility practice and in accordance with the directives of the Federal Energy Regulatory Commission, 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 the Federal Energy Regulatory Commission;

NOW, THEREFORE, for the consideration stated herein, and for other good and valuable consideration, including the Parties' mutual reliance upon the covenants contained herein, the receipt of which hereby is acknowledged, PJM and MISO hereby agree as follows:

2.1 Abbreviations and Acronyms.

2.1.1 "AC"
AC shall mean alternating current.

2.1.2 "AFC"
AFC shall mean Available Flowgate Capability.

2.1.2.a "APC"
APC shall mean Adjusted Production Cost.

2.1.3 "ARR"
ARR shall mean Auction Revenue Rights.

2.1.4 "BA"
BA shall mean Balancing Authority.

2.1.5 "BAA"
BAA shall mean Balancing Authority Area.

2.1.5.a "CBBRP"
CBBRP shall mean Cross-Border Baseline Reliability Project.

2.1.5.b "CBMEP"
CBMEP shall mean Cross-Border Market Efficiency Project.

2.1.6 "CBM"
CBM shall mean Capacity Benefit Margin.

2.1.7 "CFR"
CFR shall mean Code of Federal Regulations.

2.1.8 "CIM"
CIM shall mean Common Information Model.

2.1.8.a "CTS"

CTS shall mean Coordinated Transaction Scheduling.

2.1.8.b "CTSD"
CTSD shall mean Coordinated Transaction Scheduling Dispatch.

2.1.9 "DC"
DC shall mean direct current.

2.1.10 "DFAX"
DFAX shall mean transfer distribution factors.

2.1.11 "EHV"
EHV shall mean Extra High Voltage.

2.1.12 "EMS"
EMS shall mean the respective Energy Management Systems utilized by the Parties to manage the flow of energy within their RC Areas.

2.1.13 "ERAG"
ERAG shall mean the Eastern Interconnection Reliability Assessment Group that is charged with multi-regional modeling.

2.1.14 "FERC" (or "Commission")
FERC shall mean the Federal Energy Regulatory Commission or any successor agency thereto.

2.1.15 "FTR"
FTR shall mean financial transmission rights.

2.1.16 "GLDF"
GLDF shall mean Generation-to-Load Distribution Factor.

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

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

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

2.1.20 "IROL"
IROL shall mean Interconnection Reliability Operating Limit.

2.1.21 "ISC"
ISC shall mean the Inter-RTO Steering Committee.

2.1.21a "ITSCED"
ITSCED shall mean Intermediate Term Security Constrained Economic Dispatch.

2.1.22 "JRPC"
JRPC shall mean the Joint RTO Planning Committee.

2.1.23 "kV"
kV shall mean kilovolt of electric potential.

2.1.24 "LBA"
LBA shall mean Local Balancing Authority.

2.1.25 "LBAA"
LBAA shall mean Local Balancing Authority Area.

2.1.25a "LEC"
LEC shall mean Lake Erie circulation.

2.1.26 "LMP"
LMP shall mean Locational Marginal Price.

2.1.26a "M2M"
M2M shall mean market-to-market.

2.1.26b "MI"
MI shall mean Michigan.

2.1.27 "MMWG"
MMWG shall mean the Multi-regional Modeling Working Group.

2.1.27a "MOPI"
MOPI shall mean the Michigan-Ontario PAR Interface.

2.1.28 "MTEP"
MTEP shall mean MISO Transmission Expansion Plan.

2.1.29 "MVAR"
MVAR shall mean megavolt amp of reactive power.

2.1.30 "MW"
MW shall mean megawatt of real power.

2.1.31 "MWh"
MWh shall mean megawatt hour of energy.

2.1.32 "NAESB"
NAESB shall mean North American Energy Standards Board or its successor organization.

2.1.33 "NERC"
NERC shall mean the North American Electricity Reliability Corporation or its successor organization.

2.1.33a "NLP"
NLP shall mean Net Load Payment.

2.1.34 "NSI"
NSI shall mean net scheduled interchange.

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

2.1.36 "OATT"
OATT shall mean the applicable open access transmission tariff.

2.1.36a "ONT"
ONT shall mean Ontario.

2.1.37 "OTDF"
OTDF shall mean Outage Transfer Distribution Factor.

2.1.37a "PAR"
PAR shall mean phase angle regulator.

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

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

2.1.40 "PSS/E"
PSS/E shall mean Power System Simulator for Engineering.

2.1.41 "PTDF"
PTDF shall mean Power Transfer Distribution Factor.

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

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

2.1.44 "RC"
RC shall mean Reliability Coordinator.

2.1.45 "RCF"
RCF shall mean Reciprocal Coordinated Flowgate.

2.1.46 "RCIS"
RCIS shall mean the Reliability Coordinator Information System.

2.1.47 "RTEP"
RTEP shall mean PJM Regional Transmission Expansion Plan.

2.1.48 "RTO"
RTO shall mean regional transmission organization.

2.1.49 "SCADA"
SCADA shall mean Supervisory Control and Data Acquisition.

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

2.1.51 "SOL"
SOL shall mean System Operating Limit.

2.1.52 "TCUL"
TCUL shall mean tap-changing-under-load.

2.1.53 "TFC"
TFC shall mean Total Flowgate Capability.

2.1.54 "TLR"
TLR shall mean Transmission Loading Relief.

2.1.55 "TOP"
TOP shall mean Transmission Operator.

2.1.56 "TRM"

TRM shall mean Transmission Reliability Margin.

2.1.57 "UDS"
UDS shall mean Unit Dispatch Systems.

2.1.58 "VAR"
VAR shall mean volt ampere reactive.

2.2 Definitions.

Any undefined, capitalized terms used in this Agreement shall have the meaning given under industry custom and, where applicable, in accordance with good utility practices.

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

2.2.2 "Affected System"
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.

2.2.3 "Agreement"
Agreement shall mean this document, as amended from time to time, including all attachments, appendices, and schedules.

2.2.4 "American Electric Power"
American Electric Power shall mean the American Electric Power Company.

2.2.4.a "Attaining Balancing Authority" or "Attaining BA"
Attaining Balancing Authority shall have the same meaning set forth in the then current version of the NERC Glossary of Terms used in NERC Reliability Standards.

2.2.4.b "Attaining Balancing Authority Area" or "Attaining BAA"
The Attaining Balancing Authority Area shall have the same meaning set forth in the then current version of the NERC Glossary of Terms Used in NERC Reliability Standards

2.2.4.c "Attaining Reliability Coordinator" or "Attaining RC"
The Attaining Reliability Coordinator is the entity that is responsible for Reliable Operation of the Bulk Electric System, as those terms are defined in the NERC Glossary of Terms, for the Attaining Balancing Authority.

2.2.4.d "Attaining Transmission Operator" or "Attaining TOP"
The Attaining Transmission Operator is the entity that operates or directs operations for the reliability of the Attaining BAA Transmission System.

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

2.2.6 "Balancing Authority"
Balancing Authority shall mean the responsible entity that integrates resource plans ahead of time, maintains load-interchange-generation balance within a Balancing Authority Area, and supports interconnection frequency in real-time. For MISO references to a BA may be applicable to a BA and/or an LBA.

2.2.7 "Balancing Authority Area"
Balancing Authority Area shall mean the collection of generation, transmission, and loads within the metered boundaries of the BA. The BA maintains load-resource balance within this area. For MISO references to a BAA may be applicable to a BAA and/or an LBAA.

2.2.8 "Bulk Electric System"
Bulk Electric System shall mean the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving load with only one transmission source are generally not included in this definition.

2.2.9 "Commonwealth Edison"
Commonwealth Edison shall mean the Commonwealth Edison Company.

2.2.10 "Confidential Information"
Confidential Information shall have the meaning stated in Section 18.1.1.

2.2.11 "Congestion Management Process"
Congestion Management Process means that document incorporated herein as Attachment 2 to this Agreement hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.11.1 "Constraint Relaxation Logic"
Constraint Relaxation Logic shall mean the logic applied in the market clearing software where the transmission limit is increased to prevent the Transmission Constraint Penalty Factor from setting the shadow price of a M2M Flowgate that is constrained.

2.2.12 "Coordinated Flowgate"
Coordinated Flowgate shall mean a Flowgate impacted by an Operating Entity as determined by one of the five 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.

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

2.2.14 "Coordinated System Plan"
Coordinated System Plan shall have the meaning stated in Section 9.3.7.

2.2.14.1.a "Coordinated Transaction Scheduling" or "CTS"
Coordinated Transaction Scheduling or CTS shall mean the market rules that allow real-time transactions to be scheduled based on a market participant's willingness to purchase energy from a source in either the MISO or PJM Balancing Authority Area and sell it at a sink in the other Balancing Authority Area if the forecasted price at the sink minus the forecasted price at the corresponding source is greater than or equal to the dollar value specified in the bid.

2.2.14.1.b "Coordinated Transaction Scheduling Dispatch" or "CTSD"
Coordinated Transaction Scheduling Dispatch or CTSD shall mean MISO's algorithm that performs various functions, including but not limited to forecasting dispatch and market clearing prices based on current and projected system conditions for up to several hours in the future.

2.2.14.a "Cross-Border Baseline Reliability Project"
Cross-Border baseline Reliability Project shall have the meaning stated in Section 9.4.4.1.1.

2.2.14.b "Cross-Border Market Efficiency Project"
Cross-Border Market Efficiency Project shall have the meaning stated in Section 9.4.4.1.2.

2.2.15 "Cross-Border Grandfathered Projects"
Cross Border Grandfathered Projects shall mean the Cross-Border Grandfathered Projects document incorporated herein as Attachment 4 to this Agreement, hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

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

2.2.17 "Effective Date"

Effective Date shall have the meaning stated in Section 12.1.

2.2.18 "Emergency Energy Transactions"
Emergency Energy Transactions shall mean the Emergency Energy Transactions document incorporated herein as Attachment 5 to this Agreement, hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.19 "Extra High Voltage"
Extra High Voltage shall mean 230 kV facilities and above stations with voltage regulating capabilities.

2.2.20 "Facilities Study"
Facilities Study shall mean a study conducted by the Transmission Service Provider, or its agent, for the interconnection customer to determine a list of facilities, the cost of those facilities, and the time required to interconnect a generating facility with the transmission system or enable the sale of firm transmission service.

2.2.21 "Feasibility Study"
Feasibility Study shall mean a preliminary evaluation of the system impact of interconnecting a generating facility to the transmission system or the initial review of a transmission service request.

2.2.22 "Firm Flow"
Firm Flow shall mean the estimated impacts of Firm Transmission Service on a particular Coordinated Flowgate.

2.2.23 "Firm Flow Limit"
Firm Flow Limit shall mean the maximum value of Firm Flows an entity can have on a Coordinated Flowgate, based on procedures defined in Sections 4 and 5 of the Congestion Management Process.

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

2.2.25 "Generation Resource"
Generation Resource shall mean a PJM Generation Capacity Resource, as that term is defined in the PJM Reliability Assurance Agreement, or a MISO Generation Resource or Capacity Resource, as those terms are defined in Module A of MISO Open Access Transmission, Energy and Operating Reserve Markets Tariff.

2.2.25.a "Generator Pseudo-Tie Market Flow Adjustment"
Generator Pseudo-Tie Market Flow Adjustment shall mean the amount of calculated energy flows removed from the Attaining Balancing Authority Market Flow for a specified

Flowgate representative of the portion of the path from the location of the pseudo-tied generator to the MISO-PJM border.

2.2.26 "Governing Documents"
Governing Documents shall mean the PJM Open Access Transmission Tariff, the PJM Operating Agreement, the PJM Consolidated Transmission Owners Agreement, the PJM Reliability Assurance Agreement, the MISO Open Access Transmission and Energy and Operating Reserve Markets Tariff, the Agreement of Transmission Facilities Owners To Organize The Midcontinent Independent System Operator, Inc., A Delaware Non-Stock Corporation," or any other applicable agreement approved by the FERC and intended to govern the relationship by and among PJM and MISO and any of their respective members or market participants.

2.2.26.a "Hold Harmless Issues"
Hold Harmless Issues shall have the meaning given in Section 4.3.

2.2.27 "Intellectual Property"
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 copyrights and any moral rights recognized by law; and (iii) any other similar rights, in each case on a worldwide basis.

2.2.28 "Interconnection Service"
Interconnection Service shall mean the service provided by the Transmission Service Provider associated with interconnecting the generating facility to the transmission system and enabling it to receive electric energy and capacity from the generating facility at the point of interconnection, pursuant to the terms of the generator interconnection agreement and, if applicable, the tariff.

2.2.29 "Interconnection Study"
Interconnection Study shall mean any of the following studies: the interconnection Feasibility Study, the interconnection System Impact Study, and the interconnection Facilities Study, or the restudy of any of the above, described in the generator interconnection procedures.

2.2.30 "Interconnection Reliability Operating Limit"
Interconnection Reliability Operating Limit shall mean a System Operating Limit that, if violated could lead to instability, uncontrolled separation(s) or cascading outages that adversely impact the reliability of the Bulk Electric System.

2.2.30.a "Intermediate Term Security Constrained Economic Dispatch"
Intermediate Term Security Constrained Economic Dispatch shall mean PJM's algorithm that performs various functions, including but not limited to forecasting dispatch and LMP solutions based on current and projected system conditions for up to several hours into the future.

2.2.31 “Interregional Coordination Process”
Interregional Coordination Process shall mean the market-to-market coordination document incorporated herein as Attachment 3 to this Agreement, hereto as it exists on the Effective Date and as it may be amended or revised from time to time.

2.2.32 “Inter-regional Planning Stakeholder Advisory Committee”
Inter-regional Planning Stakeholder Advisory Committee shall have the meaning given under Section 9.1.2.

2.2.33 “Inter-RTO Steering Committee”
Inter-RTO Steering Committee shall have the meaning given in the Joint and Common Market Agreement.

2.2.34 “Joint and Common Market”
Joint and Common Market shall mean, a group of initiatives that are intended to result in achievement of the following objectives: (i) Provide the highest level of inter-regional reliability; (ii) Deliver the lowest cost energy and ancillary services to load across the combined MISO and PJM Markets; and (iii) Plan, build and operate the combined MISO and PJM transmission facilities for maximum joint benefit across the markets.

2.2.35 “Joint and Common Market Agreement”
Joint and Common Market Agreement shall mean the Agreement Concerning Inter-regional Coordination, Including Development of Joint and Common Market, executed by the Parties on or about February 12, 2003.

2.2.36 “Joint Coordinated System Plan”
Joint Coordinated System Plan shall have the meaning given under Section 9.3.2.

2.2.37 “Local Balancing Authority”
Local Balancing Authority shall mean an operational entity which is: (i) responsible for compliance to NERC for the subset of NERC Balancing Authority Reliability Standards defined for its local area within the MISO Balancing Authority Area, and (ii) a party (other than MISO) to the Balancing Authority Amended Agreement which, among other things, establishes the subset of NERC Balancing Authority Reliability Standards for which the LBA is responsible.

2.2.38 “Local Balancing Authority Area”
Local Balancing Authority Area shall mean the collection of generation, transmission, and loads that are within the metered boundaries of an LBA.

2.2.39 “Locational Marginal Price” or “LMP”
Locational Marginal Price or LMP shall mean the market clearing price for energy at a given location in a Party’s RC Area, and “Locational Marginal Pricing” shall mean the processes related to the determination of the LMP.

2.2.40 "LMP Contingency Processor"
LMP Contingency Processor shall mean that Locational Marginal Price pricing computer program referred to in Section 11.2.1.

2.2.41 "Market-Based Operating Entity"
Market-Based Operating Entity shall mean an Operating Entity that operates a security constrained, bid-based economic dispatch bounded by a clearly defined market area.

2.2.42 "Market Flows"
Market Flows shall mean the calculated energy flows on a specified Flowgate as a result of dispatch of generating resources serving market load within a Market-Based Operating Entity's market (excluding tagged transactions).

2.2.43 "Market Monitor"
Market Monitor shall monitor market power and other competitive conditions in the Markets and make reports and recommendations as appropriate.

2.2.44 "MISO"
MISO has the meaning stated in the preamble of this Agreement.

2.2.44a "MOPI M2M Flowgate"
MOPI M2M Flowgate shall mean a Flowgate subject to the requirements in Section 10 of the Interregional Coordination Process.

2.2.44.b "Native Balancing Authority" or "Native BA"
The Native Balancing Authority shall have the same meaning set forth in the then current version of the NERC Glossary of Terms Used in NERC Reliability Standards.

2.2.44.c "Native Balancing Authority Area" or "Native BAA"
The Native Balancing Authority Area shall have the same meaning set forth in the then current version of the NERC Glossary of Terms Used in NERC Reliability Standards.

2.2.44.d "Native Reliability Coordinator" or "Native RC"
The Native Reliability Coordinator is the entity that is responsible for Reliable Operation of the Bulk Electric System, as those terms are defined in the NERC Glossary of Terms, where the pseudo-tied unit is physically located.

2.2.44.e "Native Transmission Operator" or "Native TOP"
The Native Transmission Operator is the entity that operates or directs operations for the reliability of the local transmission system where the pseudo-tied unit is physically located.

2.3.45 "NERC Compliance Registry"
NERC Compliance Registry shall mean a listing of all organizations subject to compliance with the approved reliability standards.

2.2.46 “Network Upgrades”
Network Upgrades shall have the meaning as defined in MISO and PJM tariffs.

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

2.2.48 “Operating Entity”
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.

2.2.49 “Outages”
Outages shall mean the planned unavailability of transmission and/or generation facilities dispatched by PJM or MISO, as described in Article VII of this Agreement.

2.2.50 “Party” or “Parties”
Party or Parties refers to each party to this Agreement or both, as applicable.

2.2.51 “PJM”
PJM has the meaning stated in the preamble of this Agreement.

2.2.51a “Project Cost”
Project Cost shall mean all costs for Network Upgrades, as determined by the RTOs to be a single transmission expansion project, including those costs associated with seeking and obtaining all necessary approvals for the design, engineering, construction, and testing the Network Upgrades. Project Cost will include costs classified by the Transmission Owners and ITCs as transmission plant using the Uniform System of Accounts or equivalent set of accounts for any Coordinating Owner, where Transmission Owners, ITCs, and Coordinating Owner have the meanings as defined under the PJM and MISO OATTs.

2.2.52 “Purchasing-Selling Entity”
Purchasing Selling Entity shall mean the entity that purchases or sells, and takes title to, energy, capacity, and interconnected operations services.

2.2.53 “Reciprocal Coordination Agreement”
Reciprocal Coordination Agreement shall mean an agreement between Operating Entities to implement the reciprocal coordination procedures defined in the Congestion Management Process.

2.2.54 “Reciprocal Coordinated Flowgate”
Reciprocal Coordinated Flowgate 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. An RCF is:

- A Coordinated Flowgate that is (a) (i) within the operational control of a

Reciprocal Entity or (ii) may be subject to the supervision of a Reciprocal Entity as a RC, and (b) affected by the transmission of energy by the Parties or by either Party of both Parties and one or more Reciprocal Entities; or

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

2.2.55 "Reciprocal Entity"
Reciprocal Entity shall mean an entity that coordinates the future-looking management of Flowgate capability in accordance with a reciprocal agreement as described in the Congestion Management Process.

2.2.55a "Regionally Beneficial Project"
Regionally Beneficial Project shall have the meaning defined under Attachment FF of the MISO OATT.

2.2.56 "Reliability Coordinator"
Reliability Coordinator shall mean that party approved by NERC to be responsible for reliability of an RC Area.

2.2.57 "Reliability Coordinator Area" or "RC Area"
Reliability Coordinator Area or RC Area shall mean the collection of generation, transmission, and loads within the boundaries of the Reliability Coordinator. Its boundary coincides with one or more Balancing Authority Areas.

2.2.58 "SCADA Data"
SCADA Data shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC reliability standard TOP-005.

2.2.59 "State Estimator"
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.

2.2.60 "System Impact Study"
System Impact Study shall mean an engineering study that evaluates the impact of a proposed interconnection or transmission service request on the safety and reliability of transmission system and, if applicable, an Affected System. The study shall identify and detail the system impacts that would result if the generating facility were interconnected or transmission service commenced without project modifications or system modifications.

2.2.61 “System Operating Limit”
System Operating Limit 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.

2.2.62 “Third Party”
Third Party refers to any entity other than a Party to this Agreement.

2.2.63 “Third Party Operating Entity”
Third Party Operating Entity shall refer to a Third Party 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.

2.2.64 “Total Flowgate Capability”
Total Flowgate Capability shall mean 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 capability 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.

2.2.64.1 “Transmission Constraint Penalty Factor”
Transmission Constraint Penalty Factor shall mean the maximum cost of the redispatch incurred to control the flows across a transmission constraint and establishes the maximum limit on the shadow price, consistent with the maximum Transmission Constraint Demand Curve value in Schedule 28-A in the MISO Tariff and the value in the Amended and Restated Operating Agreement of PJM Interconnection, L.L.C., Schedule 1, Section 5.6.2 and the parallel provisions in Attachment K – Appendix of the PJM Open Access Transmission Tariff.

2.1.65 “Transmission Loading Relief”
Transmission Loading Relief shall mean the procedures used in the Eastern Interconnection as specified in NERC reliability standard IRO-006 and the NAESB business practice WEQ-008.

2.2.66 “Transmission Operator”
Transmission Operator shall mean the entity responsible for the reliability of its “local” transmission system, and that operates or directs the operations of the transmission facilities.

2.2.67 “Transmission Owner”
Transmission Owner shall mean a Transmission Owner as defined under the Parties’ respective tariff.

2.2.68 "Transmission Reliability Margin"
Transmission Reliability Margin shall mean 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.

2.2.69 "Transmission Service Provider"
Transmission Service Provider shall mean the entity that administers the transmission tariff and provides transmission service to transmission customers under applicable transmission service agreements.

2.2.70 "Transmission System Emergencies"
Transmission System Emergencies are conditions that have the potential to exceed or would exceed an IROL.

2.2.71 "Unit Dispatch Systems"
Unit Dispatch Systems shall mean those dispatch systems utilized by the Parties to dispatch generation units by calculating the most economic solution while simultaneously ensuring that each of the boundary constraints is resolved reliably.

2.2.72 "Voltage and Reactive Power Coordination Procedures"
Voltage and Reactive Power Coordination Procedures are the procedures under Article XIX for coordination of voltage control and reactive power requirements.

ARTICLE III
OVERVIEW OF COORDINATION AND INFORMATION EXCHANGE

3.1 Ongoing Review and Revisions.

PJM and MISO will use this Joint Operating Agreement, to the extent applicable, for the coordination of TOP, BA, RC and other functions for which they may have registered in the NERC Compliance Registry. The Parties have agreed to the coordination and exchange of data and information under this Agreement to enhance 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, including changes to the boundaries of a Party in its capacity as an RTO, changes to the boundaries of, or identities of, BAs or TOPs for which a Party serves as RC, changes in response to findings and recommendations of the United States Department of Energy or NERC concerning the outage of August 14, 2003, and changes upon the commencement of market-to-market implementation. 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.

4.1.1 <u>Real-Time and Projected Operating Data</u>.

4.1.1.1 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:
- (i) Generation status of the units in each Party’s RC Area;
- (ii) Transmission line status;
- (iii) Real-time loads;
- (iv) Scheduled use of reservations;
- (v) TLR information, including calculation of Market Flows;
- (vi) Redispatch information, including the next most economical generation block to decrement/increment; and
- (vii) List of real-time constraints that are binding in the real-time market solution.

(b) Projected operating information consists of:
- (i) Merit order for generators participating in the Parties’ markets;
- (ii) Maintenance schedules for generators and transmission facilities in either of the Parties’ RC Area;
- (iii) Transmission Service Reservations reflecting firm purchase and sales;

(iv) Independent power producer information including current operating level, projected operating levels, Outage start and end dates;

(v) The planned and actual operational start-up dates for any permanently added, removed or significantly altered transmission segments;

(vi) Points of interconnection between the two Parties that will be permanently removed or added (this information to be shared by the Party responsible for the action shortly before taking such action); and

(vii) The planned and actual start-up testing and operational start-up dates for any permanently added, removed or significantly altered generation units.

4.1.3 Models.

Purpose: EMS models contain detailed representations of the transmission and generation configurations within each RTO 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 format or another mutually agreed upon electronic format, but shall provide each other with updates of the model information in an agreed upon electronic format 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 drawing 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.

Pseudo-Tie Requirements: The Native Balancing Authority Area and the Attaining Balancing Authority Area shall coordinate unit modeling with respect to the rules of the Native Balancing Authority and Attaining Balancing Authority for modeling a pseudo-tie. If the Native Balancing Authority and Attaining Balancing Authority do not have this information, modeling data will be requested from the entity seeking to pseudo-tie the generating unit. This includes coordination of specific technical details for each pseudo-tie. Article 11.3 provides more detail on pseudo-tie requirements.

4.1.4 Operations Planning Data.

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 4.1.4.11 inclusive, or any components thereof. Each request shall specify the information sought and the requested 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 Information but to the extent any of this data overlaps previously defined operating data in Section 4.1.2, it is considered Confidential Information.

4.1.4.1 Flowgates.

(a) Flowgate definitions including seasonal TFC, TRM, CBM, and a & b multipliers;

(b) Flowgates to be added on demand;

(c) List of Coordinated and Reciprocal Coordinated Flowgates;

(d) List of Flowgates to recognize when selling point-to-point service (if different than list of Coordinated Flowgates); and

(e) Requirements under Section 5.1.7.

4.1.4.2 Transmission Service Reservations.

(a) Daily list of all reservations, hourly increment of new reservations;

(b) List of reservations to exclude;

(c) Requirements under Sections 5.1.4 and 5.1.5; and

(d) List of long-term firm reservations not subject to rollover rights.

4.1.4.3 Available Flowgate Capability 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, twice per month.

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) Identify the origin of the forecast (*e.g.*, identity of RTO, RC, BA, etc.);

(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.

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.

4.1.4.6 Designated Network Resources.

(a) Network Integration Transmission Service Specifications;

(b) Designated Network Resource information; and

(c) To the extent that Designated Network Resources operate between the markets administered by the Parties:

(i) Indication of treatment as pseudo tie or dynamic/static schedules;
(ii) Rules for sharing output between joint owners; and
(iii) Transmission arrangements.

4.1.4.7 BAA Net Interchange from Reservations and Tags.

(a) Any grandfathered agreements that do not appear in OASIS; and

(b) If tags and reservations can not be used to develop BAA net interchange, then provide hourly unit commitment information for all generators in the BAA.

4.1.4.8 Dynamic Schedules.

(a) List of dynamic schedules;

(b) Identification of the dynamic schedules are being used to move load between the Parties' respective RC Areas;

(c) Identification of marginal generation zones; and

(d) Requirements under Section 5.1.11.

4.1.4.9 Controllable Devices.

(a) Phase shifters;

(b) Market-dispatchable demand response resources greater than 50 MW.

(c) DC lines; and

(c) Back-to-back AC/DC converters.

4.1.4.10 Generation and Transmission Outages.

(a) Generation Outages that are planned or forecast, as soon as practicable, including all data specified in Section 5.1.1;

(b) Transmission Outages that are planned or forecast, as soon as practicable, 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.

4.1.4.11 Exchange of Operating Data.

The Parties shall exchange such information as the Market Monitors of PJM and MISO may request, singly or jointly, in order to facilitate monitoring of markets in accordance with the Parties' respective FERC-approved market monitoring plans.

5.1.4 Transmission Interchange Schedules/Net Scheduled Interchange.

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 reservation and interchange schedules/NSI, as required to permit accurate calculation of AFC values. Due to the high volume of this data, the Parties shall either post this data to a mutually agreed upon site for downloading or utilize tag dump information by the other Party as required by its own process and timing requirements.

In order to capture the impacts of the pseudo-tied unit on Flowgates, neither MISO, nor PJM nor the entity seeking to pseudo-tie that unit shall tag or request to tag the scheduled energy flows from a pseudo-tied Generation Resource because information about-the pseudo-tie is included in the M2M congestion management procedure.

6.1 Reciprocal Coordination of Flowgates Operating Protocols.

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 and calculations of firmness (firm, non-firm, network, non-firm hourly) for real-time operations applicable to the Party's Coordinated Flowgates. Additionally, each Party agrees to respect the allocations defined by the allocation process set forth in Section 6 of the Congestion Management Process.

6.1.2 Coordination Process for Reciprocal Coordinated Flowgates.

The Parties shall maintain the process and timing for exchanging their respective AFC calculations and Firm Flow calculations/allocations with respect to all RCFs. Further, the process will allocate Flowgate capability on a future-looking basis, including the allocation of 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 controllable Flowgate, 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. The operating practices of the controllable device will be made available to MISO and PJM before a change is made. To the extent the controllable device is able to maintain the schedule across the controllable Flowgate, there are no parallel flows and a historical allocation based on parallel flows will not occur. In this instance, the use of the controllable 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 the schedule across the controllable Flowgate, there will be a historical allocation 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.

6.5 Sharing Contract Path Capacity.

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. PJM will not be able to deal directly with companies with which it does not physically or contractually interconnect and MISO will not be able to deal directly with companies with which it does not physically or contractually interconnect.

9.1 Administration; Committees.

9.1.1 Joint RTO Planning Committee.

The ISC shall form, as a subcommittee, a Joint RTO Planning Committee (JRPC), 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 JRPC to serve a one-year calendar term. The ISC 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 JRPC shall coordinate the coordinated system planning under this Agreement.

For the purpose of coordinated system planning, the JRPC shall meet no less than twice per year. The JRPC may meet more frequently during the development of a Coordinated System Plan as determined to be necessary by the Parties.

9.1.1.1 JRPC Responsibilities

The JRPC is the decision making body for coordinated system planning. The Interregional Planning Stakeholder Advisory Committee (IPSAC) and other stakeholder groups may provide input to the JRPC.

Responsibilities of the JRPC include the following:

(a) On an annual basis the JRPC shall conduct a review of identified transmission issues in accordance with section 9.3.7.2.a of this Agreement.

(b) The JRPC, with input from the IPSAC, shall determine if a Coordinated System Plan study should be performed. If yes, such study shall be performed in accordance with section 9.3.7.2.b.

(c) Prepare and document detailed procedures for the development of power system analysis models. At a minimum, and unless otherwise agreed to by the Parties, the JRPC shall develop common power system analysis models to perform coordinated system 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 JRPC will direct the performance of a detailed review of the appropriateness of applicable power system models.

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

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

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

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

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

9.1.1.2 Participating in Multi-Party Studies

The JRPC may combine with or participate in similarly established joint planning committees amongst multiple entities engaging in coordinated planning studies under tariff provisions or established under other joint agreements to which a Party is a signatory, for the purpose of providing for broader inter-regional planning coordination.

9.1.1.3 Coordinated System Planning Website

Each Party shall host its own website for communication of information related to interregional transmission coordination procedures. Under its direction, the JRPC shall coordinate with the Parties to ensure that all information and documents posted on each Party's respective website is accurate and consistent. Each Party's website shall contain, at a minimum, the following information:

(a) Link to this Joint Operating Agreement
(b) Notice of scheduled IPSAC meetings

(c) Links to materials for IPSAC meetings
(d) Documents relating to Coordinated System Plan studies
(e) The following information related to long-term regional transmission plans, which may include:
  (i) The long-term transmission needs identified through each Party's then-current long-term regional transmission planning process;
  (ii) Any Interregional Project proposal identified by the Parties in response to long-term transmission needs
  (iii) The voltage level, estimated cost, and estimated in-service date of the Interregional Project proposal identified by the Parties as part of long-term regional transmission planning
  (iv) The Interregional Project proposals, if any, selected to meet long-term transmission needs, and
  (v) The results of any cost-benefit evaluation of such selected Interregional Project proposals performed, as required by each Parties' governing documents, with such results including both any overall benefits identified (which may occur across multiple transmission planning regions), as well as any benefits particular to each transmission planning region

9.1.2 <u>Interregional Planning Stakeholder Advisory Committee</u>.
The Parties shall form an IPSAC, in which participation is open to all stakeholders. The IPSAC shall facilitate stakeholder review and input into coordinated system planning with respect to the development of the Coordinated System Plan. IPSAC meetings shall be facilitated by the JRPC.

For the purpose of coordinated system planning, the IPSAC shall meet no less than once per year. The IPSAC may meet more frequently during the development of a Coordinated System Plan study as determined to be necessary by the Parties.
The JRPC shall meet annually with the IPSAC to review identified transmission issues and provide input on whether a Coordinated System Plan study should be performed. IPSAC meetings shall be on a mutually agreed to date determined by the JRPC.

The IPSAC will provide input to the JRPC on whether a Coordinated System Plan study should be performed pursuant to Section 9.3.7.2.a. If it is determined by the JRPC that a study should be performed, the IPSAC will provide input to the JRPC during the performance of the Coordinated System Plan study pursuant to Section 9.3.7.2.b.

9.2 Data and Information Exchange.

9.2.1 <u>Annual Data and Information Exchange Requirement</u>
In support of interregional planning coordination, each Party shall provide the other with the following data and information on an annual basis (or other basis, as appropriate) and will follow the stipulations for such exchange as noted below.

(a) Power flow models for projected system conditions for the planning horizon (up to the next ten (10) years or twenty (20) years, as appropriate) that include planned generation development and retirements, planned transmission facilities and seasonal load projections.

(b) System stability models with detailed dynamic modeling of generators and other active elements.

(c) Production cost models for projected system conditions for the planning horizon that include generation and load forecasts and planned transmission facilities.

(d) Assumptions used in development of above power flow, stability and production cost models.

(e) Contingency lists for use in power flow, stability, and production cost analyses.

(f) For each new long-range planning cycle, information regarding their respective long-term transmission needs, as well as long-term regional transmission facilities selected to meet those needs, as developed in each Party's ongoing long-term regional transmission planning process.

Models provided will be consistent with those used in the respective Party's planning processes, including the processes of the NERC Transmission Planners of the Parties as may be necessary for the reviews performed under Section 9.3.5.2. Formats for the exchange of data will be agreed upon by the Parties from time to time. Parties can provide the best available information and will not be required to develop unique models to meet the requirements of this Agreement. Data compiled through other multi-regional modeling efforts can be used to meet the data exchange requirements of this Agreement as agreed to in writing by both Parties. This annual data exchange will be completed during the first quarter of the calendar year, unless Parties agree in writing to a different timeline.

9.2.2 **Data and Information Exchange upon Request**

In addition to the data and information specified in Section 9.2.1, each Party shall provide the other with the following data and information upon request. Unless otherwise indicated, such data and information shall be provided as requested by either Party, as available, within 30 calendar days from the date of such request or on a mutually agreed to schedule.

(a) Any updates to data exchanged in accordance with Section 9.2.1.

(b) Power flow models and assumptions needed for review of a Parties NERC Transmission Planner proposed plans pursuant to Section 9.3.5.2. Such models and assumptions are those that produce the Bulk Electric System needs of the Transmission Planners in the MISO and PJM regions driving reliability, economic transmission enhancement or expansion, public policy, or operational performance upgrades.

(c) Short-circuit models for transmission systems that are relevant to the coordination of planning between the two Parties.

(d) The regional plan document produced by the Party and any long-term or short-term reliability assessment documents produced by the Party, the timing of each planned enhancement, and estimated in-service dates.

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

(f) Identification and status of interconnection and long-term firm transmission service requests that have been received, including associated studies.

(g) Transmission system maps in electronic or hard copy format for the Party's bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between the two Parties.

(h) 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.

9.3 Coordinated System Planning.

The primary purpose of coordinated transmission planning and development of the Coordinated System Plan is to ensure that coordinated analyses are performed to identify expansions or enhancements to transmission system capability needed to maintain reliability, improve operational performance, enhance the competitiveness of electricity markets, or promote public policy. The Parties will conduct such coordinated planning as set forth in this Section 9.3 and subsections thereof.

9.3.1 Single Party Planning.

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 OATT or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of the Party, NERC, applicable regional reliability councils, or any successor organizations, and any and all applicable requirements of federal, state, or provincial laws or regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents its annual regional plan prepared according to the procedures, methodologies, and business rules documented by the region. 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, information on requests received from generation resources that plan on permanently retiring or suspending operation consistent with the timelines of each Party's OATT for such studies, and the identification of proposed transmission system enhancements that may affect the Parties' respective systems.

9.3.2 Coordinated System Plan.

The Coordinated System Plan is the result of the coordination of the regional planning that is conducted under this Agreement. 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 as further described in Section 9.3.7. The Coordinated System Plan shall also include 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. To the extent that the JRPC agrees to combine with or participate in similarly established joint planning committees amongst multiple planning entities engaging in coordinated planning studies as provided for under Section 9.1.1.2, the coordinated planning analyses of this Protocol may be integrated into any joint coordinated planning analyses engaged in by the multiple parties, provided that the requirements of the Coordinated System Plan are integrated into the scope of such joint coordinated planning analyses.

9.3.3 Analysis of Requests for Interconnection Service.

In accordance with the procedures under which the Parties provide Interconnection Service, each Party will coordinate with the other to conduct studies required in determining the impact of a request for Interconnection Service. Results of such coordinated studies will be included in the impacts reported to the Project Developer and Interconnection Customer as appropriate. The process for coordination is detailed below:

(a) Consistent with the data exchange provisions of this Agreement, the Parties will exchange current modeling data as necessary for the study and coordination of request for Interconnection Service that may impact the Affected System. This will include the associated update of the other Party's relevant requests for Interconnection Service, contingency elements, monitoring elements data, and other data as may be required.

(b) The coordinated Interconnection Studies will determine the potential impact on the host system and on the Affected System. The host system will be responsible for communicating coordinated Interconnection Study results to the Project Developer or Interconnection Customer.

(c) Relative Queue Priority under PJM OATT, Parts VII, VIII and IX

The relative queue priority between the PJM New Service Request Cycles and MISO Definitive Planning Phase ("DPP") cycles shall be established as follows:

(i) The requests for Interconnection Service included in the cycle having the earlier Decision Point I (DP1) close date will have higher queue priority. DP1 is the first Project Developer and Interconnection Customer Decision Point following Phase I of the PJM New Service Request Cycle or MISO Definitive Planning Phase ("DPP") cycle. For purposes of Affected System studies performed by PJM, PJM shall establish the same relative queue priority for all MISO regions, if applicable, within a given cycle, based on the earliest DP1 close date of the DPP Central, East-ATC, East-ITC, and West regions.

(ii) Requests for Interconnection Service in MISO and PJM will not be considered to have equal queue priority. In the event that both Parties have cycles with the same DP1 close date, queue priority for such cycles shall be established based on each Party's respective anticipated start date for Decision Point II (DP2), calculated as the first day after of the close of Phase II, with the earlier start date having higher queue priority.

(d) Relative Queue Priority Under PJM OATT, Part VI

For all requests for Interconnection Service prior to the MISO DPP 2022 cycle and PJM Transition Cycle No. 1 (TC1), the following are the established queue priority for each Party:

(i) The relative queue priorities as determined by the methodology in effect at the time are:

a. MISO queue priority from the highest to the lowest: DPP 2018, AD1, AD2, DPP 2019, AE1, AE2, AF1, DPP 2020, AF2, AG1, DPP 2021.

b. PJM queue priority from the highest to the lowest: AD1, AD2, AE1, DPP 2018, AE2, AF1, AF2, DPP 2019, DPP 2020, AG1, DPP 2021.

(ii) For any subsequent restudies requests for Interconnection Service prior to the MISO DPP 2022/PJM TC1 cycles, MISO and PJM will utilize the queue priority established by subsection (d)(i).

(e) The Parties will coordinate and mutually agree on the nature of studies to be performed to determine the impacts of the interconnection on the Affected System.

(i) The transmission reinforcement and the study criteria used in the coordinated Interconnection Studies will conform to and incorporate provisions as outlined in the PJM Manuals and MISO Business Practices Manuals and the Parties' respective OATTs.

(ii) The PJM and PJM transmission owner study requirements, reinforcement criteria and cost allocation rules will apply to studies performed to determine impacts on the PJM transmission system when PJM evaluates the impact of MISO requests for Interconnection Service on PJM transmission facilities.

(iii) The MISO and MISO transmission owner study requirements, reinforcement criteria and cost allocation rules will apply to studies performed to determine impacts on the MISO transmission system when MISO evaluates the impact of PJM requests for Interconnection Service on MISO transmission facilities. During the course of MISO's Interconnection System Impact Study for Affected System, MISO shall apply Energy Resource Interconnection Service (ERIS) criteria to all of PJM's requests for Interconnection Service. Detailed information about the modeling process and assumptions used by MISO for such analysis when MISO is the Affected System are in MISO's Generator Interconnection Business Practices Manual, BPM-015.

(iv) For all tie lines between MISO and PJM, if a Party identifies a criteria violation on a tie line path interconnecting the PJM and MISO transmission systems and the limiting element(s) on such tie line path is not under the authority of the Party that identified the criteria violation, then the limiting element(s) for the tie line path will be required to be upgraded and implemented in accordance with the business practices and OATT of the Party that owns or controls the limiting element(s) such that it is no longer a limiting element (i.e. the final facility rating or limit needs to satisfy the identifying system's requirement).

(v) In case the host system study and Affected System study for the same cycle identify different upgrades and/or have different contributors, MISO and PJM shall develop and coordinate the final upgrade scope and cost allocation.

(vi) The identification of all impacts on the Parties' transmission systems shall include a description of the scope of the required Network Upgrades, and an estimated planning level cost of the Network Upgrades.

(vii) If the Parties cannot mutually agree on the nature of the studies to be performed, they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement. The Parties will strive to minimize the costs associated with the coordinated study process.

(viii) During the course of Affected System studies, MISO will sink the output of a PJM New Service Request in the same area or subregion, if applicable, as PJM, and PJM will sink the output of a MISO Interconnection Request in the same area or subregion, if applicable, as MISO.

(f) MISO Interconnection System Impact Study for Affected System for PJM New Service Requests

The Interconnection System Impact Study for Affected System by MISO for PJM New Service Requests will be coordinated as follows (also see Figure 1 for process flow):

(i) During the course of PJM's Phase I studies, PJM shall monitor the MISO transmission system and provide to MISO the draft results of the potential impacts to the MISO transmission system. This monitoring will include an examination of the potential for projects to impact the MISO system by determining whether the project under study has a $\geq$ 3 percent distribution factor on MISO facilities that operate $\geq$ 69kV to less than 500 kV or $\geq$ 10 percent distribution factor on MISO facilities that operate at or above 500 kV, under system intact conditions. MISO will provide PJM a list of the interconnection project(s) that will be included in the MISO Affected System studies prior to the PJM Phase I completion date.

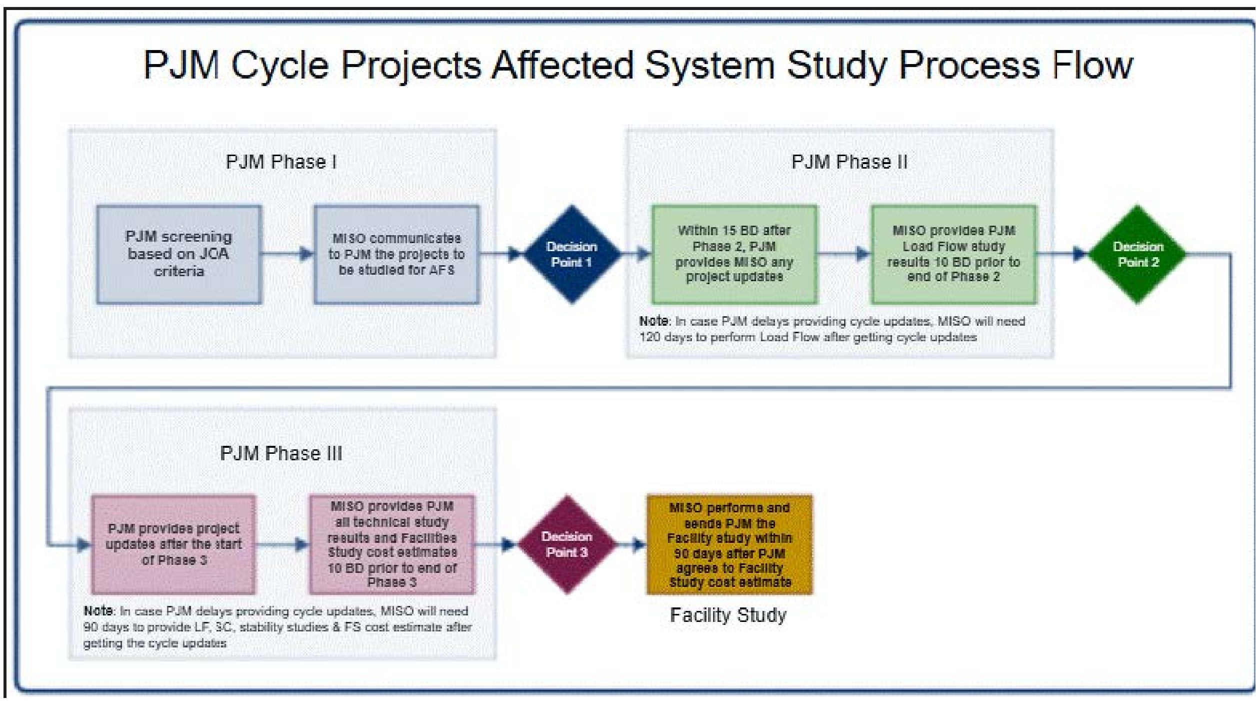
(ii) Following the posting, pursuant to PJM OATT, of the PJM Phase I System Impact Study (SIS) report and within fifteen (15) business days following the completion of DP1, PJM shall provide updated New Service Request information to MISO. MISO and the MISO transmission owners shall study the impact(s) of the PJM New Service Request(s) on the MISO transmission system and MISO will provide Affected System study results from load flow studies to PJM no later than ten (10) business days prior to the Phase II SIS posting date, on condition that PJM provided the updated project information allowing a 120 calendar day Affected System study period. PJM shall provide stability and short circuit study data to MISO prior to the start of PJM's DP2.

(iii) Prior to commencing the PJM Phase III SIS study, PJM shall provide MISO the latest available information necessary, including but not limited to project status, description and analytical modeling data for MISO and the MISO transmission owners to study the impact of the PJM New Service Request(s) on the MISO transmission system. MISO and the MISO transmission owners may study the impact of the PJM New Service Request(s) on the MISO transmission system and provide the study results, including load flow, short circuit, and stability studies, to PJM 10 business days prior to the PJM Phase III SIS posting date, on condition that PJM provided the updated project information allowing a 90 calendar day Affected System study period. Together with the final study results, MISO shall provide a Facilities Study cost estimate to PJM. MISO and MISO transmission owners shall complete the Facilities Study and provide the study report(s) to PJM within 90 calendar days after PJM agrees to the study cost estimate.

(iv) A PJM New Service Request project relying on the Network Upgrades identified in the MISO Interconnection System Impact Study for Affected System shall have limited injection rights until those Network Upgrades are placed into service. Upon request, MISO shall determine the necessary injection limits associated with the PJM New Service Request that will be implemented in Real Time until the necessary upgrades identified through MISO's Affected System analysis are placed in service.

(v) The results received from MISO, including any required Network Upgrades, shall be included in the PJM System Impact Study or Facilities Study report consistent with the PJM OATT.

Figure 1: PJM Cycle Projects Affected System Study Process Flow



(g) PJM Affected System Study for MISO Interconnection Requests: The Affected System study for MISO Interconnection Requests will be coordinated as follows (also see Figure 2 for process flow):

(i) During the course of MISO's Phase I studies, MISO shall perform screening analysis to monitor the PJM transmission system and provide to PJM the draft results of the potential impacts to the PJM transmission system. This monitoring will include an examination of the potential projects to impact the PJM system through determination if the project under study has a ≥ 5 percent distribution factor or ≥ 5 MW impact or ≥ 1 percent of facility rating on any PJM facilities 69kV or above under normal and contingency conditions. PJM shall provide to MISO a list of the interconnection project(s) that will be included in the PJM Affected System study prior to MISO's Phase I completion date.

(ii) Prior to commencing the MISO DPP Phase II study, MISO shall forward to PJM the latest available information necessary for PJM and the PJM transmission owners to study the impact of the MISO Interconnection Request(s) included in such study on the PJM transmission system. PJM shall study the impact(s) of the MISO Interconnection Request(s) on the PJM transmission system and provide the Affected System Study results including load flow studies to MISO 10 business days prior to MISO Phase II SIS posting date, on condition that MISO provided the updated project information allowing 90 calendar days Affected System studies period. Stability and short circuit study data shall be provided to PJM prior to the start of MISO's DP2.

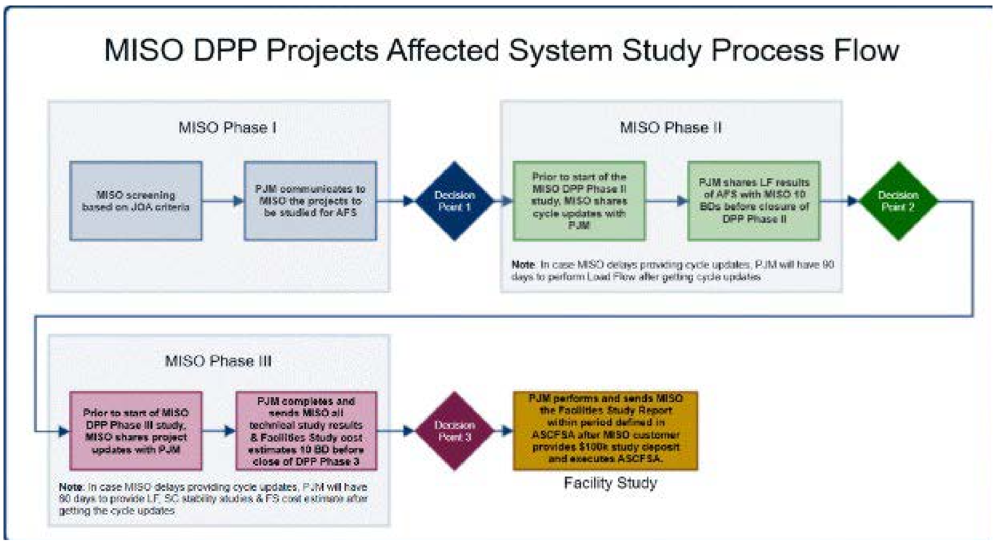
(iii) Prior to commencing the MISO DPP Phase III study, MISO shall forward to PJM the latest available information necessary for PJM and the PJM transmission owners to study the impact of the MISO Interconnection Request(s) on the PJM transmission system. PJM shall study the impact(s) of the MISO Interconnection Request(s) on the PJM transmission system and provide Affected System Study results, including load flow, short circuit, and stability studies, to MISO 10 business days prior to MISO Phase III SIS posting date, on condition that MISO provided the updated project information allowing 60 calendar days Affected System Study period. Together with study results, PJM shall tender an Affected System Customer Facilities Study Application and Agreement (PJM OATT, Part IX, Subpart L) to the MISO Interconnection Customer and they will have 30 calendar days to execute. Upon agreement execution, PJM and PJM transmission owners shall complete Facilities Study and provide study report(s) to MISO within the timeframe agreed upon in the Affected System Customer Facilities Study Application and Agreement.

(iv) During the course of PJM's Affected System Study for MISO interconnection projects, PJM shall apply testing applicable to Energy Resource Interconnection Service (ERIS) modeling methodology. Detailed information about the modeling process and assumptions used by PJM for such analysis, when PJM is the Affected System, are located in PJM's Manual 14B, Addendum 2.

(v) The results received from PJM, including any required Network Upgrades, shall be included in the MISO System Impact Study report.

(vi) Any MISO interconnection project relying on those Network Upgrades identified by PJM Affected System studies shall have limited injection rights until those Network Upgrades are placed into service. Upon request, in accordance with the Interim Deliverability Procedure outlined in PJM Manual 14H, PJM shall determine the necessary injection limits associated with the MISO Interconnection Request that will be implemented in Real Time until the necessary upgrades identified through PJM's Affected System studies are in-service.

Figure 2: MISO DPP Projects Affected System Study Process Flow



(h) Affected System Impact Study Costs: The host system will collect from the Interconnection Customer or Project Developer the costs incurred by the Affected System associated with the performance of the PJM Affected System Impact Study or MISO's Interconnection System Impact Study for Affected System and forward collected amounts to the affected Party.

(i) Affected System Facilities Studies: If the coordinated interconnection system impact study identifies constraints that require Network Upgrades on the Affected System to mitigate them, then the Affected System may perform its own Facilities Study, in conjunction with the host system's Facilities Studies.

(j) Affected System Facilities Study Costs:

(i) PJM New Service Requests receiving MISO Affected System Study: PJM will collect from the PJM Project Developer the costs incurred by MISO associated with the performance of the Interconnection Facilities Study and forward collected amounts to MISO.

(ii) MISO DPP Interconnection Requests receiving PJM Affected System Study: PJM will tender an Affected System Customer Facilities Study Application and Agreement (PJM OATT, Part IX, Subpart L) to the MISO Interconnection Customer. PJM will collect the requisite deposit from the MISO Interconnection Customer for the affected PJM Transmission Owner to perform the Affected System Facilities Study.

(k) Billing

(i) Affected System Impact Study Billing

a. PJM Performing Affected System Impact Study for MISO Projects

PJM will perform Affected System impact studies for MISO projects and issue monthly invoices to MISO. Each invoice will include a lump sum amount for all studies conducted during the billing period. PJM monthly billing for the current Affected System impact study shall cease after sixty (60) days from the study completion.

MISO shall pay PJM within thirty (30) calendar days of receiving the invoice, utilizing funds from MISO Interconnection Customers' study funds. Payments should be remitted as specified in the invoice.

b. MISO Performing Interconnection System Impact Study for Affected System for PJM Projects

MISO will perform Affected System impact studies for PJM projects and issue invoices within sixty (60) days to PJM following completion of the study.

PJM shall pay MISO within thirty (30) days of receiving the invoice, utilizing funds from PJM Project Developers' study funds. Payments shall adhere to the terms outlined in the invoice.

(ii) Affected System Facility Study Billing

a. PJM Performing Affected System Facility Study for MISO Projects

For MISO projects requiring PJM's Affected System facility study, MISO Interconnection Customers will provide a deposit of $100,000 per project to PJM before the commencement of the studies per the Affected System Customer Facilities Study Application and Agreement with PJM. Upon receipt of the deposit and Affected System Customer Facilities Study Application and Agreement, PJM and the relevant PJM Transmission Owners will begin the affected system facility study process.

The deposit is refundable, and any unused funds for each project will be returned to the MISO Interconnection Customer upon completion of the study. If additional funds are required to complete the study, PJM will notify the MISO Interconnection Customer immediately. The MISO Interconnection Customer will then have thirty (30) calendar days to provide the additional required funds.

PJM will maintain detailed accounting of the deposits and provide updates to MISO as needed to ensure transparency.

b. MISO Performing Interconnection Facilities Study for PJM Projects

For PJM projects identified to require MISO's affected system facility studies, MISO will first estimate the funding required to complete the facility studies. The estimated amount will be submitted to PJM for review and approval along with the final Phase III MISO Interconnection System Impact Study for Affected System results. Once PJM agrees with the estimate, PJM will provide MISO with the required deposit amount to fund the study utilizing funds from PJM Project Developers' study funds.

The deposit is refundable, and any unused funds for each project will be returned to PJM upon completion of the study. If additional funds are required to complete the study, MISO will notify PJM immediately. PJM will then have (30) calendar days to provide the additional required funds.

Upon receipt of the deposit, MISO will initiate the facility study process.

MISO will maintain detailed accounting of the deposits, as per MISO regular business processes, and provide updates to PJM if requested to ensure transparency.

(l) If the results of the coordinated study process indicate that Network Upgrades are required in accordance with procedures, guidelines, criteria, or standards applicable to the Affected System, the host system will identify the need for such Network Upgrades in the appropriate study report and agreement prepared for the Interconnection Customer or Project Developer.

(m) 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 Affected System and consistent with applicable federal, state or provincial regulatory policy.

(n) In the event that Network Upgrades are required on the Affected System, then Interconnection Service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of Interconnection Service that can commence after each milestone.

(o) Each Party will maintain separate requests for Interconnection Service queues. The Parties will maintain a composite listing of requests for all projects that have been identified as potentially impacting the systems of both Parties. These lists will be presented annually to the IPSAC.

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. The process for the coordination of studies and Network Upgrades shall be documented in the respective Party's business practices manuals that are publicly available on each Party's website. Both Parties' manual language shall be coordinated so as to ensure the communication of requirements is consistent and includes the following:

(a) The Parties will coordinate the calculation of AFC 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 coordinate the study of the request, pursuant to each Party's business practices manuals, which will determine the potential impact on each Party's system. The Party receiving the request will be responsible for communicating coordinated study results to the customer requesting such service.

(c) If the potentially impacted Party determines that its system may be materially impacted by the service, and the nature of the service is such that a request on the potentially impacted Party's OASIS is unnecessary (i.e., the potentially impacted Party is "off the path"), then the potentially impacted 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 minimize the costs associated with the coordinated study process. The JRPC 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 mutually agreed upon study scope and timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement.

(e) If constraints are identified during the coordinated study on the impacted system, then the potentially impacted Party may perform its own analysis in conjunction with the studies performed by the Party that has received the request for service. The customer whose request for service requires mitigation of constraint(s) found on an impacted Party's system shall enter into the appropriate facilities study agreement as required under the impacted Party's OATT. During the Facilities Study, the potentially impacted Party will conduct its own Facilities Study as a part of the Party receiving the request's Facilities Study. 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 Party 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.

(i) In the event that Network Upgrades are required on the potentially impacted Party's system, then transmission service will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

9.3.5 Analysis of Incremental Auction Revenue Rights Requests.

The Parties will coordinate, as deemed appropriate, the conduct of any studies in response to a request for Incremental Auction Revenue Rights ("Incremental ARRs") ("Incremental ARR Request") made under one Party's tariff to determine its impact on the other Party's system. Results of such coordinated studies will be included in the impacts reported to the customer requesting Incremental ARRs as appropriate. Coordination of studies and Network Upgrades will include the following:

(a) The Parties will coordinate the base Firm Flow Entitlement values associated with the Coordinated Flowgates that may be impacted by the Incremental ARR Request.

(b) Upon receipt of an Incremental ARR Request or the review of studies related to the evaluation of such request, the Party receiving the Incremental ARR Request will determine whether the other Party is potentially impacted. If the other Party is potentially impacted, the Party receiving the Incremental ARR Request will notify the other Party and convey the information provided in the request in addition to but not limited to the list of impacted constrained facilities.

(c) During the System Impact Study, the potentially impacted Party may participate in the coordinated study by providing input to the studies to be performed by the Party receiving the Incremental ARR Request. The potentially impacted Party shall determine the Network Upgrades, if any, needed to mitigate constraints on identified impacted facilities. The Parties shall coordinate to ensure any proposed Network Upgrades maintain the reliability of each Party's transmission system.

(d) Any coordinated System Impact Studies will be performed in accordance with the mutually agreed upon study timeline requirements developed by the Parties. If the Parties cannot mutually agree on the nature and timeline of the studies to be performed they can resolve the differences through the dispute resolution procedures documented in Article XIV of this Agreement in accordance with applicable tariff provisions.

(e) During the Facilities Study, the potentially impacted Party may conduct its own

Facilities Study as a part of Facilities Study being conducted by the Party that received the Incremental ARR request. The study cost estimates indicated in the Facility Study Agreement between the Party receiving the request and the Incremental ARR customer will reflect the costs and the associated roles of the study participants, including the potentially impacted Party. 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 Incremental ARR Request shall collect from the Incremental ARR customer, and forward to the potentially impacted Party, the agreed upon payments associated with the performance of such studies.

(g) 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 Party, the Party receiving the request will identify the need for such Network Upgrades in the System Impact Study prepared for the Incremental ARR customer.

(h) The construction of such Network Upgrades will be subject to the terms of the potentially impacted Party's tariff, the agreement among owners transferring functional control of transmission facilities to the control of the potentially impacted Party, and applicable federal, state, or provincial regulatory policy.

(i) In the event that Network Upgrades are required on the potentially impacted Party's system, the Incremental ARR will commence on a schedule mutually agreed upon among the Parties. This schedule will include milestones with respect to the Network Upgrade construction and the amount of service that can commence after each milestone.

Infra (b).

9.3.6 Analysis of Generator Deactivations (retirements and suspensions).

(a) The Party ("Noticed Party") receiving a new request from a generation owner to retire, deactivate, or mothball (or suspend operations as defined under the MISO Tariff) its generation unit will notify the other Party of such deactivation request no later than five (5) business days after receipt of the notice by the Noticed Party. The other Party ("Other Party") will determine if any study is required to evaluate potential impacts to its system due to the proposed generator deactivation in the Noticed Party's system. Any studies required due to a notice to deactivate (retire or suspend operations as defined under the MISO Tariff) will be performed under each Party's respective Tariff. Each Party's regional study results will be documented and provided to the other Party for informational purposes only.

(b) Both Parties will share all information necessary to evaluate potential impacts to their respective systems due to the notice. Such coordination shall provide for:

(i) Exchange of current power flow modeling data as necessary for the study and coordination of generator deactivations (retirements and suspensions). This will include the associated update of the other Party's generator availability, contingency elements, monitoring elements data, and other data as may be required.

(ii) Coordination by the Parties to align the assumptions of any analyses during development of the scope of any required studies. The scope design will include, as appropriate, evaluation of the transmission system against the criteria applicable to each Party for such studies.

(c) Following the exchange of information pursuant to section 9.3.6(b), the Other Party will conduct screening and evaluation of projects needed to mitigate identified impacts on its system. The Other Party will use reasonable efforts to perform an initial assessment and provide an indication of the impacts on its system to the Noticed Party within 65 days of receipt of the notice from the Noticed Party. The Other Party will provide a list of potential system reinforcements required on its system and estimated time for completion of those system reinforcements to the Noticed Party as soon as they are available.

(d) Each Party will be responsible for any regional Network Upgrades or other mitigation required on their respective system as a result of a request to deactivate (retirement or suspension).

(e) Any impact(s) on the Other Party's system identified in the analysis will not be used to determine the need to retain the generator requesting to deactivate.

(f) The identification of Network Upgrades required for generator deactivation (retirement or suspension) in the Other Party's system may require coordination through the JRPC. The Parties will endeavor to make such information available to the JRPC in a timely manner following publication of information through the Parties' regional processes. Additional coordination, as may be needed, will be conducted pursuant to the Coordinated System Plan study process as mutually agreed to be the Parties in accordance with the provisions of Section 9.3.7.

(i) The JRPC will incorporate any needed regional upgrades that may be identified by the generator deactivation studies coordinated pursuant to this section 9.3.6 into the annual review processes of Section 9.3.7 for the purpose of determining if there is a more efficient or cost effective Interregional Reliability Project that may replace one or more of the identified regional Network Upgrades required for the generator deactivation.

(ii) The JRPC will consider the results of the deactivation analyses forwarded to the committee at the next scheduled JRPC meeting or within 30 days of receipt of the completed study information from both Parties. Depending on the timing of the receipt of the study information, the JRPC will determine the most appropriate process for including the regional deactivation results into the development of the Coordinated System Plan. Such process will include IPSAC review according to the Coordinated System Plan process of Section 9.3.7.

(iii) Throughout the interregional review process any confidentiality provisions of the Parties Tariff's will be respected. Critical identified Interregional Reliability Projects for which the need to begin development is urgent will be presented to the Parties' Boards for approval as soon as possible after identification through the Coordinated System Plan study process. Other identified Interregional Reliability Projects presented to the Parties' Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade.

9.3.7 Development of the Coordinated System Plan.

9.3.7.1

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 Section, to obtain financial compensation due to the impact of another Party's plans or additions. The Coordinated System Plan will be finalized only after the IPSAC has had an opportunity to review it and respond. The Coordinated System Plan shall:

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

(b) Describe the results of the identification and joint evaluation of interregional transmission facilities that may be more efficient or cost-effective transmission facilities to address long-term transmission needs;

(c) Set forth actions to resolve any impacts that may result across the seams between the Parties' systems due to the integration described in the preceding part (a); and

(d) Describe results of the joint transmission analysis for the combined transmission systems, as well as explanations, as may be necessary, of the procedures, methodologies, and business rules utilized in preparing and completing the analysis.

9.3.7.2

Coordination of studies required for the development of the Coordinated System Plan will include the following: 1) annual issues review to determine the need for a Coordinated System Plan study described in Section 9.3.7.2.a; and 2) Coordinated System Plan study described in Section 9.3.7.2.b.

(a) Determine the Need for a Coordinated System Plan Study

(i) On an annual basis, beginning in the fourth quarter of each calendar year and continuing through the first quarter of the following calendar year, the Parties shall perform an annual evaluation of transmission issues identified by each Party, including issues from the respective Party's market operations and annual planning processes, or Third-Parties. This annual review of transmission issues will be administered by the JRPC on a mutually agreed to schedule taking into consideration each Party's regional planning cycles.

(ii) The JRPC's annual review of transmission issues shall include the following steps:

a. Exchange of the following information during the fourth quarter of each calendar year or as specified below:

i. Regional issues and newly approved regional projects located near the interface or expected to impact the adjacent region;

ii. Newly identified regional transmission issues for which there is no proposed solution;

iii. Interconnection and long-term firm transmission service requests under coordination by the Parties located near the interface or expected to impact the adjacent region will be exchanged pursuant to sections 9.3.3 and 9.3.4, respectively;

iv. Market-to-market historical flowgate congestion between the Parties.

b. Joint review by the Parties of regional issues and solutions in January of each calendar year;

c. Receipt of Third Party issues in the first quarter of each calendar year;

d. Review of regional issues with input from stakeholders at the IPSAC meeting conducted during the first quarter of each calendar year; and

e. Decision by the JRPC on whether or not to conduct a Coordinated System Plan study.

(iii) The JRPC through each Party's respective electronic distribution lists shall provide a minimum of 60 calendar days advance notice of the IPSAC meeting to be held in the first quarter of each year to review identified transmission issues. Stakeholders may identify and submit transmission issues and supporting analysis no later than 30 calendar days in advance of the meeting, for consideration by the IPSAC and JRPC.

(iv) Within 45 days following the annual issues evaluation meeting with IPSAC in the first quarter of the calendar year, the JRPC will determine, taking into consideration input provided by the IPSAC, the need to perform a Coordinated System Plan study. A Coordinated System Plan study shall be initiated by either of the following: (1) each Party in the JRPC votes in favor of performing the Coordinated System Plan study; or (2) if after two consecutive years in which a Coordinated System Plan study has not been performed, and one Party votes in favor of performing a Coordinated System Plan study. The JRPC shall inform the IPSAC of the decision whether or not to initiate a Coordinated System Plan study within five business days of the JRPC's decision.

(v) When a Coordinated System Plan study is determined to be necessary, the JRPC shall agree to the start date of the study and identify whether it is a targeted study as defined in this Section at (vi) or a more complex, two-year cycle study as defined in this Section at (vii).

(vi) If a Coordinated System Plan study includes targeted studies of particular areas, needs or potential expansions to ensure that the coordination of the reliability and efficiency of the Parties' transmission systems, then such targeted studies will be conducted during the first half of the calendar year. In years when the Coordinated System Plan study includes only targeted studies as defined herein, they may be conducted at any time during the calendar year but shall be completed within the calendar year in which they are identified.

(vii) A Coordinated System Plan study may include more complex, longer duration studies that may involve development of a joint model, as appropriate, to address reliability, market efficiency or public policy needs. Such studies will be conducted on a two-year cycle commencing in the third quarter of the first year of the two-year cycle, if the need is determined by the JRPC. A Coordinated System Plan study scheduled on a two-year cycle will conclude no later than the end of the second year of the two-year cycle.

(a) For a Coordinated System Plan study scheduled on a two-year cycle, the JRPC will provide notice to the IPSAC in the fourth quarter of the year preceding commencement of the two-year study cycle.

(b) The first year of the two-year study cycle will consist of model preparation and issue identification and be timed in accordance with each RTO's regional planning processes for model preparation and issue identification. Two-year study cycle activities and their interaction with regional activities are further described in the applicable sections of 9.3.7, particularly in section 9.3.7.2(b)(vii).

(viii) When a Coordinated System Plan study is determined to be necessary by the JRPC, the specific study process steps will depend on the type and scope of the study. The JRPC shall provide a schedule and binding deadlines for each step in the Coordinated System Plan study process no later than 15 days after the IPSAC meeting provided for in Section 9.3.7.2(b)(ii) following the JRPC's decision to initiate such study.

(b) Coordinated System Plan Study Process

(i) 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.

(ii) The JRPC will develop a scope and procedure for the coordinated planning analysis. The scope of the studies will include evaluations of issues resulting from the annual coordinated review and analysis of the Parties transmission issues. The scope and schedule for the Coordinated System Plan study will include the schedule of IPSAC review and input at all stages of the study. Study scope and assumptions will be documented and provided to the IPSAC for review and comment at an IPSAC meeting scheduled no later than 30 days after the decision to conduct a Coordinated System Plan study.

(iii) Ad hoc study groups may be formed as needed to address localized seams issues or to perform targeted studies of particular areas, needs, or potential expansions and to ensure the coordinated reliability and efficiency of the systems. Under the direction of the Parties, study groups will formalize how activities will be implemented. Targeted studies will utilize the best available regional models for transmission and market efficiency analysis

(iv) The Coordinated System Plan study will consider the identified issues reviewed by the JRPC and IPSAC for further evaluation of potential remedies consistent with the criteria of this Protocol and each Party's criteria. Stakeholder input will be solicited for potential remedies to identified issues, which includes stakeholder and transmission developer proposals for Interregional Projects. The study scope developed under Section 9.3.7.2(b)(ii) will include the schedule for acceptance of such stakeholder Interregional Project proposals including supporting analyses that address issues identified in the JRPC solicitation. There shall be no requirement to select an Interregional Project, even if it meets evaluation criteria and benefits, and each Party shall provide the rationale behind each selection or non-selection decision.

(v) The Parties will document the scope and assumptions including the process and schedule for the conduct of the study. The scope design will include, as appropriate, evaluation of the transmission system against the reliability criteria, operational performance criteria, economic performance criteria, and public policy needs applicable to each Party.

(vi) The Parties will use planning models that are developed in accordance with the procedures to be established by the JRPC. If the JRPC develops joint study models, the JRPC will do so consistent with the models and assumptions used for the regional planning cycle most recently completed, or underway, as appropriate. If the Coordinated System Plan study requires transmission evaluations driven by different regional needs (for example transmission that addresses any combination of needs including regional reliability, economics and public policy), then the coordination of studies, models, and assumptions will include the analyses appropriate to each region. The Parties will develop compromises on assumptions when feasible and will incorporate study sensitivities as appropriate when different regional assumptions must be accommodated. Known updates and revisions to models will be incorporated in a comprehensive fashion when new base planning models are available. Prior to the availability of a new comprehensive base model, known updates will be factored in, as necessary, into the review of results. Models will be available for stakeholder review subject to confidentiality and Critical Energy Infrastructure Information (CEII) processes of the Parties. The IPSAC will have the opportunity to provide feedback to the JRPC regarding the study models.

(vii) When Coordinated System Plan studies are undertaken pursuant to a two-year study cycle defined in this Section at (a)(vii), the following schedule will be followed unless otherwise mutually agreed to by the Parties.

a. Parties will provide updated identification of regional issues identified in this Section at (a) by January of the second year of the two-year cycle.

i. If MISO conducts a regional Market Congestion Planning Study as part of the MTEP, MISO will use that Market Congestion Planning Study to identify the MISO regional issues that will be incorporated into the Coordinated System Plan study. MISO regional issues identified in a regional Market Congestion Planning Study will be made available for incorporation into the Coordinated System Plan study between November of the first year and January of the second year of the two-year cycle. If MISO does not conduct a regional Market Congestion Planning Study as part of the MTEP, MISO will use MISO's most recent production cost models to identify regional issues and will provide the regional issues identified for incorporation into the Coordinated System Plan study between November of the first year and January of the second year of the two-year cycle. For matters addressing reliability specifically, MISO will use issues identified in the most recent MTEP report, available annually in December, and the reliability projects, submitted in September of the prior year being considered for inclusion in the current MTEP. MISO will include these projects in the regional issues made available for incorporation into Coordinated System Plan study.

ii. PJM regional reliability and Market Efficiency analyses will be used to identify regional issues that will be incorporated into the Coordinated System Plan study. Regional reliability analysis proceeds throughout the calendar year identifying PJM issues, including issues near the seam. These seams issues are presented to all stakeholders at the PJM Transmission Expansion Advisory Committee meetings and the PJM competitive window process, if eligible. PJM's long-term economic analysis cycles are conducted during two consecutive calendar years according to the schedule presented to stakeholders at the Transmission Expansion Advisory Committee meetings. The development of the economic model occurs throughout the first three quarters of the first year of the two-year study cycle and is made available for stakeholder review and comment prior to opening PJM's long-term proposal window later in the first year of the two-year study cycle. Both regional and interregional project proposals are submitted through the PJM project proposal windows consistent with Schedule 6, section 1.5.8(c) of the PJM Amended and Restated Operating Agreement. Interregional Project proposals entered into a PJM short-term or long-term proposal window will be analyzed along with PJM regional project proposals. Consistent with Schedule 6, section 1.5.8(d) of the PJM Amended and Restated Operating Agreement, PJM, in consultation with the Transmission Expansion Advisory Committee, shall determine the more efficient or cost effective transmission enhancements and expansions available for incorporation into the Coordinated System Plan study.

b. MISO and PJM regional models will be made available to the IPSAC for stakeholder review and comment in the first year of the two-year cycle as detailed below:

   i. MISO will make available its most recent MTEP cycle long-term multi-year power flow models for reliability analysis and multi-year production cost models with multiple economic Futures for economic analysis, annually by November 30.

   ii. PJM will make available its most recent regional reliability model that is updated annually in the first quarter of each calendar year. PJM's regional economic model is prepared according to the assumptions and schedule as discussed at the Transmission Expansion Advisory Committee meeting scheduled in the first quarter of year one of PJM's long-term regional planning cycle. The economic model is available for stakeholder review and feedback during the third quarter of the first year of PJM's two year planning cycle.

c. Stakeholder Interregional Project proposals, satisfying applicable regional and interregional requirements, will be accepted by PJM in its project proposal windows as detailed in Schedules 6 and 6-C of the PJM Amended and Restated Operating Agreement.

d. Stakeholder identification of Interregional Project proposals, satisfying the applicable regional and interregional requirements, will be accepted in the MISO MTEP regional process ~~approximately between January through March of the second year of the two-year cycle~~. A precise timeframe will be provided in each MTEP cycle.

e. The Parties will evaluate each Interregional Project proposal in its regional process, using the criteria and benefit determination in Sections 9.4.4.1 and 9.4.4.2 and applicable subsections, during the second year of the two-year cycle to determine if a project is eligible for inclusion in the respective regional plans. If recommended by the JRPC per Section 9.3.7.2(b)(xi), an Interregional Project must be presented to the respective Parties' Boards for approval and, if approved, in each Party's regional plan to become an Interregional Project. The Parties shall present the proposed projects, including any proposed Interregional Projects, to their respective Board of Directors or Managers by December 31 of the second year of the two-year cycle.

i. In MISO, regional analysis typically occurs between February and September each year. Potential Interregional Projects will be evaluated against the MISO regional criteria and collectively with other potential regional projects to ensure cohesive benefits.

ii. In PJM, regional reliability analysis occurs annually. Regional market efficiency analysis occurs biennially. Interregional evaluations will occur in PJM's regional proposal window process as outlined in Section 9.3.7.2(b)(vii)(a)(ii).

(viii) The IPSAC will have the opportunity to provide input into the development of potential solutions. Feedback by the IPSAC stakeholders shall be provided to each region consistent with each region's regional processes for accepting project proposals. Potential solutions submitted through each region's respective planning processes specific to submitting project proposals shall be communicated between the Parties in a timely manner. The JRPC will be responsible for the screening and evaluation of potential solutions, including evaluating the proposed projects for designation as an Interregional Project pursuant to Section 9.4.4.1. Proposed solution criteria and benefits shall be evaluated by each region pursuant to Sections 9.4.4.1 and 9.4.4.2 and applicable subsections.

(ix) Transmission upgrades identified through the analyses conducted according to this Protocol and satisfying the applicable Protocol and regional planning requirements will be included in the Coordinated System Plan after the conclusion of the Coordinated System Plan study and applicable regional analyses.

(x) The JRPC shall produce and submit to the IPSAC for review reports documenting the Coordinated System Plan study, including the transmission issues evaluated, studies performed, solutions considered, and, if applicable, recommended Interregional Projects with the associated cost allocation to the Parties pursuant to Section 9.4.4.2. The review of any proposed allocation of costs under the Coordinated System Plan pursuant to Section 9.4.4 will be accomplished during the periodically scheduled IPSAC meetings held during the course of the Coordinated System Plan study according to this Section 9.3.7.2. In addition, explanations why proposed Interregional Projects did not move forward in the process will be provided in the final Coordinated System Plan study report to the IPSAC for review. The IPSAC shall be provided the opportunity to provide input to the JRPC on the Coordinated System Plan study reports. Results of, comments and responses to comments on the final Coordinated System Plan study report shall be posted on each Party's website. Fulfillment of the requirements of this subsection will be accomplished through periodically scheduled IPSAC meetings held during the course of the Coordinated System Plan study.

(xi) The JRPC's recommended Interregional Projects identified in the Coordinated System Plan study shall be reviewed by each Party through its respective regional processes. These regional reviews will be integrated into the interregional process as further described in Sections 9.3 and 9.4. Transmission plans to resolve problems will be identified, included in the respective plans of the Parties and will be presented to the respective Parties' Boards for approval and implementation using each Party's procedures for approval. Critical upgrades for which the need to begin development is urgent will be reviewed by each Party in accordance with their procedures and presented to the Parties' Boards for approval as soon as possible after identification through the coordinated planning process. Other projects identified will be reviewed by each Party in accordance with their procedures and presented to the Parties' Boards for approval in the normal regional planning process cycle as long as this cycle does not delay the implementation of a necessary upgrade. The JRPC shall inform the IPSAC of the outcome of each Party's review of the recommended Interregional Projects.

(c) Targeted Market Efficiency Project Study

The Coordinated System Plan study may include a Targeted Market Efficiency Project study consistent with Section 9.3.7.2(b)(iii). The Targeted Market Efficiency Project study will evaluate, analyze, and determine upgrades to remedy identified historical market-to-market congestion on Reciprocal Coordinated Flowgates on the PJM-MISO market border. Identified issues under this section will be expected to persist and are not expected to be substantially alleviated by system changes planned in the five (5) year planning horizon. Identification of issues will include, but not be limited to, the RTO's determination, based on historical operational information, of any historical flowgate congestion known to be caused by outage conditions. The RTOs will not consider for purposes of a Targeted Market Efficiency Project study, historical congestion on a Reciprocal Coordinated Flowgate caused by outages or will determine a proportionally reduced amount of congestion associated with that flowgate, as appropriate. Any Targeted Market Efficiency Project study initiated by the JRPC under this section will be conducted under the process defined for a Coordinated System Plan study, except as modified by this section and the following subsections.

(i) Issues identified in the Targeted Market Efficiency Project study will be reviewed to determine the cause of the market issues, including: (a) the specific limiting elements, (b) verification of the ratings of the limiting elements, (c) whether approved, planned system changes may alleviate the issue, (d) whether outages contribute to all or a portion of the historical congestion, (e) estimates of the cost of upgrading the limiting elements, and (f) whether upgrades to the limiting elements could substantially relieve the constraints;

(ii) Using the results of the review under subsection (i) and the applicable criteria of Section 9.4, the JRPC will provide to the IPSAC the criteria used to evaluate whether congestion is likely to be persistent. The JRPC will post results of the analysis for input from the IPSAC and will solicit proposals for Targeted Market Efficiency Projects that meet the criteria of Sections 9.3.7.2(c) and 9.4 applicable to a Targeted Market Efficiency Project;

(iii) The JRPC will determine the list of limiting element upgrades and Targeted Market Efficiency Project proposals to analyze the benefits to PJM and MISO for presentation to and input from the IPSAC;

(iv) Prior to making the determination outlined in Section 9.3.7.2(c)(vi) below, the JRPC will provide to the IPSAC any additional criteria used to evaluate potential Targeted Market Efficiency Project solutions;

(v) The JRPC will provide to the IPSAC for input an explanation of: (a) why the JRPC did not evaluate whether a potential Targeted Market Efficiency Project could economically address congestion on a particular congested Reciprocal Coordinated Flowgate, and (b) why a potential Targeted Market Efficiency Project that the JRPC evaluated is not recommended to the MISO and PJM Boards for approval;

(vi) Based on the analysis and stakeholder process conducted consistent with Sections 9.3.7.2(c) and 9.4, the JRPC will determine any Targeted Market Efficiency Project proposals to recommend to their respective Boards for approval; and

(vii) Solely for the purposes of conducting the Targeted Market Efficiency Project analysis, the regional processes referred to in Section 9.3.7.2(b) will be the JRPC analysis conducted for the Targeted Market Efficiency Project study according to the scope and procedures developed under Sections 9.3.7.2(b)(ii) and 9.3.7.2(c). The joint JRPC analysis together with the associated stakeholder process will be sufficient for any resulting JRPC recommended Interregional Transmission Projects to be presented for approval to the respective RTOs' Board as described in 9.3.7.2(b)(xi).

9.4 Allocation of Costs of Network Upgrades.

9.4.1 Network Upgrades Associated with Interconnections.

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 Party's OATT.

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 Party's OATT.

9.4.3 Network Upgrades Associated with Incremental Auction Revenue Rights Requests.

When under Section 9.3.5 it is determined that the granting of an Incremental ARR 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 Affected System's tariff provisions.

9.4.4 Network Upgrades Under Coordinated System Plan.

The Coordinated System Plan will identify Interregional Projects as: (i) Cross-Border Baseline Reliability Projects ("CBBRP"), (ii) Interregional Reliability Projects, (iii) Interregional Market Efficiency Projects, (iv) Interregional Public Policy Projects, and (v) Targeted Market Efficiency Projects. Consistent with the applicable OATT provisions, the Coordinated System Plan will designate the portion of the Interregional Project Cost for each such project that is to be allocated to each RTO on behalf of its Market Participants. The JRPC will determine an allocation of costs to each RTO for such Network Upgrades based on the procedures described below. The proposed allocation of costs will be reviewed with the IPSAC and the appropriate multi-state entities and posted on the internet web site of the two RTOs. Stakeholder input will be solicited and taken into consideration by the JRPC in arriving at a consensus allocation of costs.

9.4.4.1 Criteria for Project Designation as an Interregional Project:

Interregional Projects must be: (1) physically located in both the MISO region and the PJM region or (2) physically located wholly in one transmission planning region but jointly determined and agreed upon to provide benefits to the other transmission planning region or both transmission planning regions. A project located solely in one region and paid for and benefiting only the adjacent region must meet the individual OATT requirements of the transmission planning region in which the project will be located to be eligible for inclusion in the local RTO's transmission plan in addition to the project criteria included in sections 9.4.4.1.1, 9.4.4.1.2 or 9.4.4.1.3. In addition, an Interregional Project approved by each RTO for inclusion in its regional plan is subject to the construction obligation under each RTO's OATT. For purposes of interregional planning between MISO and PJM, these Interregional Projects will be designated in accordance with the following criteria:

9.4.4.1.1 Cross-Border Baseline Reliability Project Criteria:

Projects that meet all of the following criteria will be designated as CBBRPs:

(i)by agreement of the JRPC, the project is needed to efficiently meet applicable reliability criteria;

(ii) the project must be a baseline reliability project as defined under the MISO or PJM Tariffs.

9.4.4.1.2 Interregional Reliability Project Criteria:

An Interregional Reliability Project must:

(i)be selected both in the MISO and PJM regional planning processes and be eligible for each region's cost allocation process; and

(ii) by agreement of the JRPC, displace one or more reliability projects in either or both PJM and MISO as defined in their respective tariffs and more efficiently or cost-effectively meet applicable reliability criteria than the displaced reliability project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Reliability Project(s) addresses reliability needs that are currently being addressed with reliability projects in its regional transmission planning process and, if so, which reliability projects in that regional transmission planning process could be displaced by the proposed Interregional Reliability Project. Reliability projects in the MISO regional transmission planning process include Baseline Reliability Projects and Multi-Value Projects that meet Criterion 3 according to MISO's OATT. MISO and PJM will quantify the benefits of an Interregional Reliability Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan that would be displaced if the proposed Interregional Reliability Project was included in the plan.

9.4.4.1.3 Interregional Market Efficiency Project Criteria:

Interregional Market Efficiency Projects must meet the following criteria:

(i)is evaluated as part of a Coordinated System Plan or joint study process, as described in Section 9.3.7 of the JOA; and

(ii) qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a Market Efficiency Project or a Multi-Value Project that meets Multi-Value Project Criterion 2 or Criterion 3 under the terms of Attachment FF of the MISO OATT (including all applicable threshold criteria), provided that any minimum Project Cost threshold required to qualify a project under either the PJM RTEP or MISO OATT shall apply the Project Cost of the Interregional Market Efficiency Project and not the allocated cost.

9.4.4.1.3.1 Determination of Benefits to Each RTO from an Interregional Market Efficiency Project:

The RTOs shall jointly evaluate the benefits to the MISO and PJM markets as follows:

(a) The RTOs shall utilize their respective tariffs' benefit metrics to analyze the anticipated annual economic benefits of construction of a proposed Interregional Market Efficiency Project to Transmission Customers of each RTO.

(b) The costs applied in the cost allocation calculation pursuant to Section 9.4.4.2.3 shall be the present value, over the same period for which the project benefits are determined, of the annual revenue requirements for the project. The annual revenue requirements for the Interregional Market Efficiency Project are determined from the estimated Interregional Market Efficiency Project installed costs and the fixed charge rate applicable in each respective RTO's regional process.

To determine the present value of the annual benefits and costs, the discount rate shall be based on the transmission owners' most recent after-tax embedded cost of capital weighted by each transmission owner's total transmission capitalization. Each transmission owner shall provide the RTOs with the transmission owner's most recent after-tax embedded cost of capital, total transmission capitalization, and levelized carrying charge rate, including the recovery period. The recovery period shall be consistent with recovery periods allowed by FERC for comparable facilities.

(c) Using the cost allocated to each RTO pursuant to Section 9.4.4.2.3 of the JOA, each RTO will evaluate the project using its internal criteria to determine if it qualifies as an economic transmission enhancement or expansion under the terms of the PJM RTEP and also qualifies as a market efficiency project under the terms of Attachment FF of the MISO OATT.

9.4.4.1.4 Interregional Public Policy Project Criteria:

Interregional Public Policy Projects must meet the following criteria:

(i) be selected both in the MISO and PJM regional planning processes and be eligible for each region's cost allocation process; and

(ii) by agreement of the JRPC, displace one or more regional projects addressing public policy in MISO or one or more public policy projects in PJM as defined in their respective tariffs and more efficiently or cost-effectively meet applicable public policy criteria than the displaced regional project(s).

Through their respective regional planning processes, PJM and MISO respectively will evaluate proposals to determine whether the proposed Interregional Public Policy Project(s) addresses public policy needs that are currently being addressed with public policy projects in its regional transmission planning process and, if so, which public policy projects in that regional transmission planning process could be displaced by the proposed Interregional Public Policy Project. Public policy projects in the MISO regional transmission planning process include Multi-Value Projects that meet Multi-Value Project Criterion 1 under the terms of Attachment FF to MISO's OATT. Public policy projects in the PJM regional transmission planning process include both economic and reliability projects. MISO and PJM will quantify the benefits of an Interregional Public Policy Project based upon the total avoided costs of regional transmission projects included in the then-current regional transmission plan for purposes of cost allocation that would be displaced if the proposed Interregional Public Policy Project was included in the plan.

9.4.4.1.5 Targeted Market Efficiency Project Criteria:

Upgrades associated with Targeted Market Efficiency Projects must meet the following criteria:

(i) Are evaluated as part of a Coordinated System Plan or joint study process as described in Section 9.3.7.2(c) and demonstrated to have an expectation for substantial relief of identified historical market efficiency congestion issues;

(ii) Have an estimated in-service date by the third-summer peak season from the year in which the project was approved;

(iii) Have an estimated installed cost less than $20 million in study year dollars;

(iv) Is determined to have expected future congestion relief, due to upgrade of that targeted Reciprocal Coordinated Flowgate, equal to the sum of annual congestion over the four (4) year period after the study year, that is equal to or greater than the estimated installed capital cost of the upgrade, including appropriate long term costs, in study year dollars, where:

a. Expected future congestion relief in the amount of the Reciprocal Coordinated Flowgate's anticipated reduction of historical congestion net of any anticipated increases in congestion on nearby flowgates based on the RTO analysis;

b. Historical congestion in PJM will be quantified in accordance with PJM OATT, Attachment K-Appendix, Section 5.1. It will include charges associated with Day-ahead and Real-time market congestion for Market Buyers, Generating Market Buyers, and Market Sellers;

c. Historical congestions in MISO will be quantified in accordance with MISO OATT, Sections 39.2.9 "Day-Ahead Energy and Operating Reserve Market Process" and 40.2.15 "Real-Time Energy and Operating Reserve Market Process." It will include charges associated with Day-Ahead and Real-Time market congestion for both load and generator buses; and

d. Annual congestion is the estimated average historical congestion based on the two historical calendar years prior to the study year.

(v) Is recommended by the JRPC as a Targeted Market Efficiency Project and approved by each RTO's Board.

9.4.4.1.5.1 Determination of Benefits of Each RTO from a Targeted Market Efficiency Project

The RTO shall jointly evaluate the benefits to the combined markets and to each RTO for each potential Targeted Market Efficiency Project resulting from Section 9.3.7.2(c), according to the following process:

(i) With input from IPSAC, determine the estimated total installed project capital cost in study year dollars;

(ii) Compare the estimated expected future congestion relief to the estimated project total installed capital cost in study year dollars. The estimated congestion relief shall equal or exceed the total installed capital cost in study year dollars, where:

a. Expected future congestion relief is the sum of each RTO's expected congestion relief, adjusted by market-to-market settlement payments.

9.4.4.2 Interregional Project Benefits and Shares:

The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO as set forth in the following subsections:

9.4.4.2.1 Cost Allocation for Cross-Border Baseline Reliability Projects

(a) **Method for Thermal Constraints:** The Coordinated System Plan shall designate the share of the Project Cost to be allocated to each RTO based on the relative contribution of the combined Load of each RTO to loading on the constrained facility requiring the need for the CBBRP. The loading contribution will be pre-determined using a joint RTO planning model developed and agreed to by the planning staffs of both RTOs. This model will form the basecase from which reliability needs on the combined systems will be determined for the Coordinated System Plan. The model, adjusted for the conditions driving the upgrade needs, will be used to calculate the DFAX for cost allocation purposes for each RTO, using a source of the aggregate of RTO generation (network resources) for each RTO to a sink of all Loads within that RTO. The DFAX is the appropriate distribution factor for the condition causing the upgrade; OTDF for contingency condition flow criteria violations, and PTDF for normal condition flow criteria violations. The DFAX calculation determines the MW flow impact attributable to each RTO on the constraint requiring the transmission system to be upgraded. The total load of each RTO for the condition modeled is multiplied by the DFAX associated with that RTO to determine the respective MW flow contribution of that RTO to the constraint. The RTOs will quantify the relative impact due to PJM's system and the relative impact due to MISO's system and then will allocate between PJM and MISO the load contributions to the reliability constraint on the system by calculating the relative impacts caused by each RTO. This methodology will determine the extent to which each RTO contributes to the need for a reliability upgrade consistent with the Coordinated System Plan modeling that determined the need for the upgrade. The MISO total load impacts will be allocated to MISO and the PJM total load impacts will be allocated to PJM. PJM and MISO will then reallocate their shares internally in accordance with their respective tariffs. By calculating the impacts in this manner, the RTOs will ensure that the relative contribution of each RTO (including both the aggravating and benefiting contributions of generation and load patterns within each RTO) to the need for a particular upgrade, is appropriately captured in the ensuing allocations, and that the allocation is consistent with the Coordinated System Plan modeling that determined the need for the upgrade.

(b) Method for Non-Thermal Constraints:
The JRPC will establish an interface, comprised of a number of transmission facilities, to serve as a surrogate for allocation of cost responsibility for non-thermal constraints. The interface will be established such that the aggregate flow on the interface best represents the non-thermal constraint which the CBBRP is proposed to alleviate. Allocation of cost responsibility for the non-thermal constraint will be determined by applying the procedures described in this Section to the interface serving as a surrogate for the constraint.

(c) Method for Projects that Also Qualify As Interregional Reliability Projects: For an Interregional Project that meets the criteria of both a CBBRP under Section 9.4.4.1.1 and an Interregional Reliability Project under Section 9.4.4.1.2, the cost will be allocated in accordance with the methodology set forth in Section 9.4.4.2.2.

9.4.4.2.2 Cost Allocation for an Interregional Reliability Project:

The cost of an Interregional Reliability Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs an Interregional Reliability Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region’s displaced reliability projects as agreed to by the RTOs to the total of the present value(s) of the estimated costs of the displaced reliability projects in both regions that have selected the Interregional Reliability Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced reliability project’s estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced reliability projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate proposed by the Transmission Owner that produces the cost estimate for the proposed project. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region's respective regional transmission planning process.

9.4.4.2.3 Cost Allocation for an Interregional Market Efficiency Project:

For Interregional Market Efficiency Projects that meet all of the qualifications in Section 9.4.4.1.3, the applicable project costs shall be allocated to the respective RTOs in proportion to the net present value of the total benefits calculated for each RTO pursuant to each RTO's respective tariff.

9.4.4.2.4 Cost Allocation for an Interregional Public Policy Project:

The cost of an Interregional Public Policy Project, selected in the regional transmission plans of both PJM and MISO, will be allocated as follows:

(i) The share of the costs for an Interregional Public Policy Project allocated to a region will be determined by the ratio of the present value(s) of the estimated costs of such region's displaced public policy projects to the total of the present value(s) of the estimated costs of the displaced public policy projects in both regions that have selected the Interregional Public Policy Project in their respective regional plans.

(ii) For purposes of this subsection, a displaced regional public policy project's estimated costs shall be determined by PJM and MISO in accordance with their respective procedures for defining project estimated costs. Notwithstanding the foregoing, both RTOs shall work to ensure that their cost estimates for displaced public policy projects are determined in a similar manner. The applicable discount rate(s) used for the MISO region shall be the discount rate developed by MISO for cost estimates for projects under review by the MISO Board of Directors. The applicable discount rate(s) used for the PJM region shall be the discount rate included in the assumptions reviewed by the PJM Board of Managers each year for use in the economic planning process.

(iii) Costs allocated to each region shall be further allocated within each region pursuant to the cost allocation methodology contained in each region's respective regional transmission planning process.

9.4.4.2.5 Cost Allocation for a Targeted Market Efficiency Project:

For Targeted Market Efficiency Projects that meet all of the qualifications in Section 9.4.4.1.5, the applicable project costs shall be allocated to the respective RTOs in proportion to the determination of expected future congestion relief for each RTO calculated pursuant to that Section.

9.4.4.3 Cost Recovery of Interregional Allocation Shares:

The cost recovery of any share of cost of an Interregional Project allocated to either RTO shall be recovered by each RTO according to the applicable tariff provisions of the RTO to which such cost recovery is allocated.

9.4.4.4 Transmission Owners Filing Rights:

Nothing in this Section 9.4 shall affect or limit any Transmission Owners filing rights under Section 205 of the Federal Power Act as set forth in the applicable Tariffs and applicable agreements.

9.4.4.5 Amendments:

The RTOs shall amend Article IX of this Agreement in accordance with the applicable tariffs and/or agreements.

9.5 Agreement to Enforce Duties to Construct and Own.

To obtain Network Upgrades under this Article IX, PJM will enforce obligations to construct and own or finance enhancements or additions to transmission facilities in accordance with the Transmission Owners Agreement, PJM Interconnection, L.L.C. First Revised Rate Schedule FERC No. 29, the West Transmission Owners Agreement, PJM Interconnection, L.L.C. Rate Schedule FERC No. 33, as either may be amended or restated from time to time, and MISO will enforce obligations to construct enhancements or additions to transmission facilities in accordance with the Agreement of Transmission Facilities Owners To Organize The Midcontinent Independent System Operator, Inc., A Delaware Non-Stock Corporation, MISO FERC Electric Tariff, First Revised Rate Schedule No. 1, as it may be amended or restated from time to time.