ISO. In the case of special meetings, the Secretary shall also give notice to all Members of the general purpose of the meeting and the nature of the business to be considered at such meeting. Such a special meeting shall be limited to the business thus specified in the case, unless at least twenty-five percent (25%) of the Members consent in writing to the consideration of other matters. The Members of record eligible to participate in any meeting shall be determined as of the date notice of the meeting is provided to the Members.

Section 3.7. ***Conduct of Meetings; Quorum; Voting.*** At all meetings of Members, the Chairman of the Board, or such other person as may be designated by the Board, shall preside. Each Member shall be entitled to one vote, and Members may vote by proxy. Twenty-five percent (25%) of the Members, or their proxies, shall constitute a quorum for the purpose of any such meeting. Except where it is otherwise provided in these Bylaws, a vote of a majority of the Members represented and voting at the meeting shall control.

ARTICLE IV

BOARD OF DIRECTORS

Section 4.1. ***General Powers.*** There shall be a Board of Directors of the Midwest ISO which shall consist of seven (7) persons plus the President. The Board may exercise all of the powers of the non-stock corporation and do all lawful acts and things (including the adoption of such rules and regulations for the conduct of its meetings, the exercise of its powers, and the management of the Midwest ISO) as it may deem proper and consistent with applicable law, the

Midwest ISO Agreement, the Transmission Tariff, the articles of incorporation, and these Bylaws, provided that authority for such actions is not reserved to the Members or Owners.

Section 4.2. ***Qualifications.*** A Director shall not be, and shall not have been at any time within two (2) years prior to or subsequent to election to the Board, a Director, Officer, or employee of a Member, User, or an affiliate of a Member or User. At all times while serving on the Board, and for two (2) years thereafter, a Director shall have no material business relationship or other affiliation with any Member or User or an affiliate of a Member or User. A Director's participation in a pension plan of a Member or User or an affiliate thereof shall not be deemed to be a material business relationship if the Member's or User's financial performance has no material effect on such pension plan. Similarly, a Director's ownership of securities in a Member or User or affiliate thereof shall not be deemed to be a material business relationship if such securities are held through a mutual fund, retirement fund, blind trust (as defined in Appendix A, Section II.E.6) or similar arrangement where the Director has no discretion to manage the assets in such an account. Of the seven (7) Directors, four (4) shall have expertise and experience in corporate leadership at the senior management or board of directors level, or in the professional disciplines of finance, accounting, engineering, or utility laws and regulation. Of the other three (3) Directors, one (1) shall have expertise and experience in the operation of electric transmission systems, one (1) shall have expertise and experience in the planning of electric transmission systems, and one (1) shall have expertise and experience in commercial markets and trading and associated risk management.

Section 4.3. ***Number; Election.*** (a) Initial Board. The initial Board shall be elected by the Members at their initial meeting from a slate of candidates presented to them by an independent executive search firm chosen by a majority vote of the signatories to the Midwest ISO Agreement, with each signatory having one vote. Such firm shall select such candidates consistent with the qualification requirements set forth in Section 4.2. The slate shall include at least two (2) candidates with the appropriate type of qualifications for each Board position. Each Member shall be entitled to cast a single vote for each of the seven (7) positions on the Board from among the candidates for each position. The candidates with the most votes shall fill the Director positions for which they were nominated. In the event of a tie among the candidates for a Board position, one (1) of the candidates shall be selected by a drawing. Two (2) Directors shall hold office for one (1) year; two (2) Directors shall hold office for two (2) years; and the final three (3) Directors shall hold office for three (3) years; and, in each foregoing case, until their respective successors are duly elected and qualified, or until their earlier resignation or removal. At the first meeting of the initial Board, the Directors shall determine each of their respective terms hereunder by a drawing.

(b) Succeeding Boards. After the election of the initial Board as provided above, succeeding Directors shall be elected to terms of three (3) years, except for any Director elected to fill a vacancy in the remainder of the term. Before the term of a Director expires, a nominating committee consisting of three Board Members whose terms are not expiring appointed by the Board and two members of the Advisory Committee selected by the Advisory Committee shall select an executive search firm to provide at least two (2) candidates to the nominating committee for each open Director position. Members may submit the names of candidates directly to the nominating committee. The Nominating Committee shall then provide at least two (2) candidates to the Board for each open position. The candidates for a specific Director position shall have the same type of qualifications as the Director being replaced, as set forth in Subparagraph 2 of this Paragraph A. At least thirty (30) days prior to the meeting of the Members at which the Directors will be elected, the Board shall distribute to the Members a slate of candidates consisting of one (1) candidate for each Director position to be filled. The Board shall also provide the Members with information on the qualifications and experience of the candidate to fill the Director seat for which each candidate is proposed. A candidate receiving a majority of the votes cast by the Members shall be elected. Should the Members fail to elect a candidate from the slate proposed by the Board, the Board shall prepare a new slate using the procedures set forth above for consideration by the Members at a meeting of the Members to be called no later than seventy-five (75) days after each election. Each Director shall serve until his successor shall have been duly elected and qualified, or until his earlier resignation or removal. Vacancies on the Board caused by a Director leaving office before the expiration of his term shall be filed by vote of the Board, which shall choose a candidate having the same type of qualifications as his predecessor from a list prepared by the nominating committee in consultation with an executive search firm chosen by the nominating committee. A Director selected to fill such a vacancy shall serve out the term of his predecessor.

Section 4.4. ***Chairman of the Board.*** The Board shall select from among its members a Chairman of the Board. The Chairman shall serve in such capacity at the pleasure of the Board until the first meeting of the Board following the next succeeding annual meeting of the

Members, or until his successor shall have been elected and have qualified. The Chairman of the Board shall, unless otherwise determined by the Board, preside over all meetings of the Board and Members, and shall sign, with the Secretary, certificates of membership, the issuance of which shall have been authorized by the Board. The Chairman shall perform all duties incident to the office of

Chairman of the Board and such other duties as from time to time may be assigned to him by the Board.

Section 4.5. ***Vice Chairman.*** The Board shall select from among its members a Vice Chairman of the Board. The Vice Chairman shall serve in such capacity at the pleasure of the Board until its first meeting following the next succeeding annual meeting of the Members, or until his successor shall have been elected and have qualified. In the absence of the Chairman of the Board, or in the event of his inability or refusal to act, the Vice Chairman shall perform the duties of the Chairman of the Board, and, when so acting, shall have all the powers of, and be subject to all the restrictions upon, the Chairman of the Board. The Vice Chairman shall also perform such other duties as from time to time may be assigned to him by the Board.

Section 4.6. ***Resignation of Directors.*** Any Director may resign his office by submitting a signed notice of resignation, delivered or mailed to the principal office of the Midwest ISO. Such notice of resignation shall state the effective date of resignation. If the notice does not indicate an effective date, the resignation shall take effect upon receipt of the notice at the principal office of the Midwest ISO.

Section 4.7. ***Removal of Directors.*** (a) Removal by Members. The Members may remove a Director by a vote of a majority of the Members. Removal proceedings may only be initiated by a petition signed by not less than twenty percent (20%) of all Members. The petition shall state the specific grounds for removal. A copy of the petition shall be provided to the FERC and to each appropriate state regulatory authority. A Director sought to be removed shall be given fifteen (15) days to respond in writing to any charges set forth in the petition. The petition shall specify either that the removal vote shall be taken at the next regular meeting of the Members or at a special meeting of the Members at a designated date, place, and time.

(b) Removal by Owners for Unauthorized Acts. If the Board of the Midwest ISO changes, or attempts to change, any of the provisions of the Midwest ISO Agreement identified in Article Two, Section IX, Paragraph C of the Midwest ISO Agreement without obtaining the requisite approval of the Owners as specified therein, or if the Board fails to enact these Bylaws or enacts any Bylaws contrary to the Midwest ISO Agreement, or if the Board fails or refuses to fulfill the duties owed to the Owners set forth in Article Three, Section III, Paragraphs B and C of the Midwest ISO Agreement, then the Board shall be deemed to have acted without authorization, and may be removed in its entirety by unanimous vote of the Owners' Committee (established by

Article Two, Section VI, Paragraph B of the Midwest ISO Agreement), provided that such removal shall be subject to approval by the FERC. Removal proceedings hereunder shall be initiated only by the delivery by the Owners' Committee to the Chairman of the Board of a statement specifying in detail the manner in which the Board has acted without authorization. The Board shall have sixty (60) days to respond to such a statement, after which the Owners may, by unanimous vote of the Owners' Committee, reaffirm their proposal to remove the Board if they are not satisfied with the Board's response. If the Owners vote unanimously to reaffirm their proposal, they shall file such proposal with the FERC and provide notice to the appropriate state regulatory authorities. Upon the FERC's approval of such proposal, the Board shall be removed in its entirety and a new Board shall be selected in accordance with the provisions for the selection of an initial Board specified in these Bylaws. The new Board so selected shall have all of the powers specified herein as belonging to the Board, including the power to replace the President and other Officers, employees, or agents of the Midwest ISO chosen by the removed Board or its predecessors. Nothing herein shall be deemed to prejudice any right any Owner may otherwise have under the FPA or other provisions of law.

Section 4.8. ***Meetings; Notification.*** Regular meetings of the Board shall be held at least quarterly, and other meetings shall be held from time to time on the call of the President, Chairman, or a majority of the

Board. A Director may participate in a meeting personally or by electronic means. Written notice of the date, location, and time of each meeting of the Board must be provided by first-class mail or by telefacsimile to each Director no later than seven (7) calendar days prior to the date of the meeting. Participation in a meeting by a Director is a waiver of any objection that the Director may make to any failure to give adequate notice under this provision. Any action required or permitted to be taken at any meeting of the Board, or of any Board Committee, may be taken without a meeting if all Directors or Board Committee members, as the case may be, consent thereto in writing, and the writing or writings are filed with the minutes of proceedings of the Board or Board Committee. Consistent with the Midwest ISO Agreement, the Board shall have all procedural authority provided and options available under Title 8 of the Delaware Corporation Law, section 141, as such law may be amended or, any successor provision thereto.

Section 4.9. ***Quorum; Voting.*** Five (5) Directors shall constitute a quorum of the Board. Except as provided in Section 4.7 of these Bylaws, the affirmative vote of a majority of the Directors present at a meeting is required to constitute any act or decision rendered by the Board.

Section 4.10. ***Accounting.*** At each quarterly meeting of the Board, or such other time as the Board directs, the Board shall require the President to submit for Board approval a full statement of the conditions of the Midwest ISO, and all business transacted by it, and, when the statement is approved, shall cause a copy of it to be sent to each Member.

Section 4.11. ***Minutes and Reports.*** The Board shall cause to be kept by the Secretary, elected by it, accurate minutes of all meetings of the Board, Members, and Board Committees. Insofar as non-Members of the Midwest ISO are concerned, these records shall be conclusive for the Board of the facts and activities stated and recorded therein.

Section 4.12. ***Director Compensation and Expenses.*** Directors shall receive from the Midwest ISO such compensation, regular or special, subject to the terms and conditions stated in the Midwest ISO Agreement, Article Two, Section Three, Paragraph D, Subparagraph 1. The independent executive search firm chosen to select a slate of candidates for election for Director positions shall set Director compensation following such election, subject to approval of the Members. If two-thirds (2/3) or more of the Members vote to reject the search firm's recommended compensation, then the recommended compensation shall be rejected. In establishing the compensation for the initial Board, if there are not yet Members, then a vote of two-thirds (2/3) or more of the signatories to the

Midwest ISO Agreement shall be required to reject the search firm's recommended compensation. If the recommended compensation is rejected, then the search firm shall be requested to submit another recommendation or another search firm may be hired for such purpose. Directors, and their successors and assigns, shall have the right to reimbursement by the Midwest ISO for all of their actual expenses reasonably incurred or accrued in the performance of their duties as Directors of the Midwest ISO.

Section 4.13. ***Annual Report.*** The Board shall annually make a written report showing the financial results of the Midwest ISO's operations during the preceding fiscal year. A copy of such report shall be furnished to each Member.

Section 4.14. ***Board Oversight.*** The Board of Directors shall oversee the President's performance of the obligations of the Midwest ISO specified in the Midwest ISO Agreement and these Bylaws. The performance of such obligations shall be carried out and executed by the President with oversight as appropriate by the Board. The Board shall establish general policies to be followed by the President and employees of the Midwest ISO in the conduct of their duties. The Board shall have the obligation to assure that the President accounts for all transactions on the Transmission System and other activities of the

Midwest ISO; submits bills for such transactions; pays the expenses of operation of the Midwest ISO; collects monies for transmission service from customers solely as agent for Owners or their designee(s) in accordance with the Transmission Tariff; and distributes monies to the Owners or their designee(s) in accordance with the Midwest ISO Agreement, any associated agreements referred to in the Midwest ISO Agreement, the Funds Trust Agreement, and the Transmission Tariff.

Section 4.15. ***Standards of Conduct.*** The Directors shall comply with the Standards of Conduct set forth in Appendix A to the Midwest ISO Agreement, and, by direction or oversight, shall require that the Officers and employees of the Midwest ISO also comply with such standards.

Section 4.16. ***Employ Staff.*** The Board shall have the power to employ staff, auditors, counsel, and other personnel as necessary to carry out the business of the Midwest ISO, and may delegate to the President all or part of such authority to employ such staff, auditors, counsel, and other personnel.

Section 4.17. ***Board Committees.*** The Board may appoint such committees of the Board of Directors as are necessary and appropriate for the conduct of the Midwest ISO's business, provided that final responsibility for any action recommended by any such committee remains with the Board.

ARTICLE V

OFFICERS

Section 5.1. ***Titles.*** The Officers of the Midwest ISO shall be the President, one or more Vice Presidents (in the discretion of the Board), and a Secretary.

Section 5.2. ***Election and Term of Office.*** The Officers of the Midwest ISO shall be elected from time to time by the Board. Each Officer shall hold office at the pleasure of the Board.

Section 5.3. ***Removal of Officers by Directors.*** Any Officer may be removed by the Board whenever, in the Board's judgment, the best interests of the Midwest ISO will be served thereby.

Section 5.4. ***President.*** The President shall serve on the Board of the Midwest ISO. The President may vote on any matter presented at a Board meeting except when the President's vote would create a tied Board vote. In that circumstance, the President shall be barred from voting. The President also may not vote on the selection of, or continued employment of the President or on the President's compensation. The President shall be included in the determination of a quorum of the Board for any meeting of the Board and in the determination of a majority vote of the Bard for any purpose. The duties of the President are as follows:

APPENDIX F

(a) Right of President to Manage. The right of the President to exercise functional control over the operation of the Transmission System, insofar as is necessary to carry out the rights, duties, and obligations of the Midwest ISO as set forth in the Midwest ISO Agreement, shall be absolute, unconditional, and free from the control and management of the Owners, who shall have only the rights specifically set forth in the Midwest ISO Agreement. The President shall have the authority to act for the Midwest ISO before any and all applicable federal or state regulatory authorities to carry out the business of the Midwest ISO.

(b) General Powers. The President shall possess and exercise any and all such additional powers as are reasonably implied from the powers contained in the Midwest ISO Agreement such as may be necessary or convenient in the conduct of any business or enterprise of the Midwest ISO. The President may (i) do and perform everything that (a) he deems necessary, suitable, or proper for the accomplishment of any of the purposes, or the attainment of any one or more of the objectives, enumerated in the Midwest ISO Agreement, or (b) that shall at any time appear conducive to, or expedient for, the protection or benefit of the Midwest ISO, and (ii) do and perform all other acts or things that are deemed necessary or incidental to the purposes set forth in the Midwest ISO Agreement.

(c) Acquire Property. The President shall have power to purchase, or otherwise acquire through leases, such property, except for transmission facilities which shall be governed by Appendix B to the Midwest ISO Agreement, as necessary to carry out the obligations of the Midwest ISO as specified in Article Three of the Midwest ISO Agreement.

(d) Prosecute Claims. The President shall have full and exclusive power and authority to demand, sue for, claim, and receive any and all revenues and monies due the Midwest ISO.

(e) Borrow. The President shall have the power to borrow money up to the level authorized by the Board for the purposes of the Midwest ISO and to give the obligations of the Midwest ISO to secure such indebtedness.

(f) Contracts. The President shall have the authority and power to make all such contracts as he may deem expedient and proper in conducting the business of the Midwest ISO, except as may be limited by the Board.

(g) Taxes and Assessments. The President shall have the power (i) to pay all taxes or assessments of whatever kind or nature imposed upon or against the Midwest ISO in connection with the Midwest ISO property, or upon or against the Midwest ISO property, or any part of such property; (ii) to do all acts and things as may be required or permitted by any present or future law for the purpose of making the activities of the Midwest ISO exempt from taxation; and (iii) for any of the above-stated purposes, to do all such other acts and things as may be deemed by him necessary or desirable.

(h) Depository. In accordance with policies set by the Board, and subject to any limitations set forth in the Midwest ISO Agreement or the Funds Trust Agreement, the President shall have the power to select a depository, and to deposit any monies or securities held by the Midwest ISO in connection with the performance of its obligations under the Midwest ISO Agreement, with any one or more banks, trust companies, or other banking institutions, that are federally insured and deemed by the President to be responsible, such monies or securities to be subject to withdrawal on notice upon demand or in such manner as the President may determine, with no responsibility upon the President for any loss that may occur by reason of the failure of the person with whom the monies or securities had been deposited properly to account for the monies or securities so deposited.

Section 5.5. ***Vice President.*** The Vice President or, if there be more than one, the Vice President designated by the Board, shall in the absence or disability of the President, exercise the powers and perform the duties of the President. Each Vice President shall exercise such other powers and perform such other duties as shall be prescribed by the Board consistent with these Bylaws. No Vice President shall be eligible to serve on the Board of the Midwest ISO except when performing the duties of the President as provided in the Midwest ISO Agreement.

Section 5.6. ***Secretary.*** The Secretary shall be responsible for the following duties:

APPENDIX F

(a) Keeping the minutes of the applicable meetings in one or more books provided for that purpose;

(b) Seeing that all notices are duly provided in accordance with these Bylaws, policies of the Midwest ISO, and any and all other documents which provide for the governance of the Midwest ISO;

(c) Maintaining custody of the records of the business of the Midwest ISO and the seal of the Midwest ISO, and affixing such seal to all certificates of membership prior to the issuance thereof and to all documents, the execution of which, on behalf of the Midwest ISO, under its seal, is duly authorized in accordance with the provisions of these Bylaws;

(d) Keeping a register of the names and post office addresses of all Members and Directors;

(e) Signing with the Chairman of the Board certificates of membership, the issuance of which shall have been authorized by the Board or Members;

(f) Keeping on file at all times at the principal office of the Midwest ISO a complete copy of the Midwest ISO Agreement, and all amendments thereto, together with these Bylaws and any policies concerning the governance of the Midwest ISO, and, at the expense of the Midwest ISO, forwarding or otherwise making available copies of such information to each of the Members and to the public to the extent required by law; and generally performing all duties instant to the office of Secretary and such other duties that, from time to time, may be assigned to the Secretary by the Board.

Section 5.7. ***Standards of Conduct.*** The Officers, agents, and employees of the Midwest ISO shall comply with the Standards of Conduct set forth in Appendix A to the Midwest ISO Agreement.

Section 5.8. ***Bonds of Officers.*** Any Officer, employee, or agent of the Midwest ISO charged with the responsibility for the custody of any of its funds or property shall give bond in such sums, and with such sureties, as the Board shall determine. The Board, in its discretion, may also require any other Officer, agent, or employee of the Midwest ISO to give bond in such amount, with such surety, as it shall determine. All premiums of the aforesaid bonds shall be paid by the Midwest ISO.

Section 5.9. ***Compensation.*** Compensation of the Officers, agents, and employees of the Midwest ISO shall be established by the Board or pursuant to the policies approved by the Board.

ARTICLE VI

EXTERNAL COMMITTEES

Section 6.1. ***Advisory Committee.*** (a) At all times there shall exist an Advisory Committee to the Board consisting of a total of twenty-three (23) representatives from the following stakeholder groups chosen as follows: (i) three (3) representatives of Owners, with one (1) seat assigned to an Owner who was a member of the Mid-Continent Area Power Pool ("MAPP") as of March 1, 2000; (ii) three (3) representatives of municipal and cooperative electric utilities and transmission-dependent utilities, with one (1) seat assigned to a Member of this group who was a member of MAPP as of March 1, 2000; (iii) three (3) representatives of independent power producers ("IPPs") and exempt wholesale generators ("EWGs"), with one (1) seat assigned to a Member of this group who was a member of MAPP as of March 1, 2000, or who is actively involved in the MAPP region (as it existed on March 1, 2000); (iv) three (3) representatives of power marketers and brokers, with one (1) seat assigned to a Member of this group who was a member of MAPP as of March 1, 2000, or who is actively involved in the MAPP region (as it existed on March 1, 2000); (v) three (3) representatives of eligible end-use customers, with one (1) seat assigned to a Member of this group who was a member of MAPP as of March 1, 2000, or who is actively involved in the MAPP region (as it existed on March 1, 2000); (vi) three (3) representatives of state regulatory authorities, with one (1) seat assigned to a Member of this group who was a member of MAPP as of March 1, 2000, or who is actively involved in the MAPP region (as it existed on March 1, 2000); (vii) two (2) representatives of public consumer groups, with one (1) seat assigned to a Member of this group who was a member of MAPP as of March 1, 2000, or who is actively involved in the MAPP region (as it existed on March 1, 2000); (viii) two representatives of environmental and other stakeholder groups, with one (1) seat assigned to a Member of this group who was a member of MAPP as of March 1, 2000, or who is actively involved in the MAPP region (as it existed on March 1, 2000); and (ix) one (1) representative of Members who, being legally unable to transfer operational control to the Midwest ISO have, entered into coordination or agency agreements with the Midwest ISO ("Coordination Members"). The Board may revise or expand the stakeholder groups as circumstances and industry structures change. The Board shall be responsible for facilitating meetings of the Advisory Committee, which shall be held at least quarterly. At such quarterly meetings, the President and at least two (2) other members of the Board shall meet with the Advisory Committee. Upon request of the Advisory Committee, Board members and the President shall use their best efforts to attend other Advisory Committee meetings. The Advisory Committee shall be a forum for its members to be apprised of the Midwest ISO's activities and to provide information and advice to the Board on policy matters of concern to the Advisory Committee, or its constituent stakeholder groups, but neither the Advisory Committee nor any of its constituent groups shall exercise control over the Board or the Midwest ISO. Nothing in the Midwest ISO Agreement shall prohibit a corporate or other entity from participating in more than one stakeholder group provided it meets the approved eligibility criteria. The reports of the Advisory Committee and any minority reports shall be presented by the President to the Board. The Board shall determine how and when it shall consider and respond to such reports. The President shall inform the Advisory Committee of any Board determination(s) with respect to such report.

(b) Members of the Advisory Committee shall be selected in the following manner:

(i) The Owners' representatives on the Advisory Committee shall be selected in accordance with Section 6.2 of these Bylaws.

(ii) The representatives of municipal and cooperative electric utilities and transmission-dependent utilities, IPPs and EWGs, power marketers and brokers, eligible end-use customers, and Coordination Members on the Advisory Committee shall be chosen by the Members belonging to such groups. Such Member groups shall propose to the Board their own methods of eligibility and voting. Approval by the Board of such procedures shall not be unreasonably withheld.

(iii) The representatives of state regulatory authorities on the Advisory Committee shall be chosen by the state public service commissions which regulate the retail electric or distribution rates of the Owners who are signatories to the Midwest ISO Agreement.

(iv) The representatives of public consumer groups and environmental and other stakeholder groups on the Advisory Committee shall be chosen by recognized consumer, environmental, and other stakeholder organizations having an interest in the activities of the Midwest ISO. The Board shall certify the organizations eligible to participate in the selection of such representatives to the Advisory Committee. Such certification shall not unreasonably be withheld. The groups so certified shall propose to the Board their own methods of eligibility and voting. Approval of such procedures shall not unreasonably be withheld.

(v) Meetings of the constituent stakeholder groups represented on the Advisory Committee need not be open to the public.

(c) In order to ensure appropriate representation on the Advisory Committee, the Board may change the size and composition of the Advisory Committee at three-year (3-year) intervals.

Section 6.2. ***Owners' Committee.*** An Owners' Committee shall exist throughout the period of the Midwest ISO Agreement. The Owners' Committee shall consist of one (1) person representing each of the

Owners who are signatories to the Midwest ISO Agreement. The Owners' Committee shall meet at its discretion to exercise the authority granted to the Owners as a group under these Bylaws, including voting upon the matters set forth in Sections 4.8(b) and 8.2(b) of these Bylaws, and under the Midwest ISO Agreement. The Owners' Committee shall select three (3) representatives to serve on the Advisory Committee established pursuant to Section 6.1 of these Bylaws.

ARTICLE VII

OPEN MEETINGS

Section 7.1. ***Open Meetings.*** Except as provided herein, all meetings of the Board, all meetings of Board Committees and working groups, all meetings of the Advisory Committee and all Members' meetings shall be open to the public. Timely notice of such meetings and copies of all materials to be addressed at such meetings shall be provided to the members of the Advisory Committee, appropriate state regulatory authorities, and the FERC and posted on the Midwest ISO's Internet World-Wide Web Site or equivalent form of electronic posting. The procedures adopted by the Board for the conduct of such meetings shall allow interested members of the public, including those stakeholders represented on the Advisory Committee, to provide oral and written comments at such meetings concerning any matter that may come before the Board, Board Committees and working groups, Advisory Committee, or Members, whichever is applicable, during the open portion of such meetings.

APPENDIX F

Section 7.2. ***Minutes.*** The meeting minutes of all meetings of the Board, Board Committees and working groups, Advisory Committee, and Members shall be made available to the public and furnished to appropriate state regulatory authorities and the FERC, upon request; provided, however, that materials or information which is privileged or confidential pursuant to Section 7.3 of these Bylaws may be redacted from such minutes. Copies of executed or final documents, such as contracts, leases, and agreements, not otherwise required to be treated as confidential shall be made available for review. In the event the basis for information being treated as confidential ceases to exist, said information shall thereafter be available for review.

Section 7.3. ***Executive Sessions to Preserve Confidentiality.*** Executive sessions (closed to the public) shall be held as necessary to safeguard the confidentiality of (a) personnel-related information; (b) information subject to the attorney-client privilege or to confidential treatment under the attorney-work product doctrine or concerning pending or threatened litigation; (c) information that is confidential under Appendix A to the Midwest ISO Agreement; (d) consideration of assumption of liabilities, business combinations, or the purchase or lease of real property or assets; (e) except as may be required by law, consideration of the sale or purchase of securities, investments, or investment contracts; (f) strategy and negotiation sessions in connection with a collective bargaining agreement; (g) discussion of emergency and security procedures; (h) consideration of matters classified as confidential by federal or state law; (i) matters to protect trade secrets, proprietary information, specifications for competitive bidding, or to discuss a specific proposal if open discussion would jeopardize the cost or siting or give an unfair competitive or bargaining advantage to any person or entity; and (j) discussion of proceedings by the Alternate Dispute Resolution Committee established under Appendix D to the Midwest ISO Agreement.

ARTICLE VIII
DUE DILIGENCE, LIABILITY, AND INDEMNIFICATION

Section 8.1. ***Due Diligence Duties.*** It shall be the duty of Directors, Officers, employees, agents, and other representatives of the Midwest ISO (a) to faithfully and diligently administer the Midwest ISO as would reasonable and prudent persons acting in their own behalf; (b) to keep correct and accurate records of all business transacted; (c) to exercise prudence and economy in the business of the Midwest ISO, including the minimization of tax liability if the Midwest ISO is not-tax exempt; (d) to act in good faith, and only for the best interests of the Midwest ISO; (e) to annually render a full and correct account of the Midwest ISO business; and (f) at the termination of the Midwest ISO, to render and to deliver all the properties and funds of the Midwest ISO in accordance with the Midwest ISO Agreement and applicable law.

Section 8.2. ***Limitations on Liability.*** No Director, Officer, agent, employee, or other representative of the Midwest ISO, and no corporation or other business organization that employs a Director of the Midwest ISO, or any Director, Officer, agent, or employee of such corporation or other business organization, shall be personally liable to the Midwest ISO, any Member, or any User for any act or omission on the part of any such Director, Officer, agent, employee, or other representative of the Midwest ISO, which was performed or omitted in good faith in his official capacity as a Director, Officer, agent, employee, or other representative of the Midwest ISO pursuant to the operation of the Midwest ISO Agreement, or in any other capacity he may hold, at the request of the Midwest ISO, as its representative in any other organization. However, this release of liability shall not operate to release such a Director, Officer, agent, employee, or other representative of the Midwest ISO from any personal liability resulting from willful acts or omissions knowingly or intentionally committed or omitted by him in breach of the Midwest ISO Agreement, for improper personal benefit, or in bad faith. Directors, Officers, agents, employees, or other representatives of the Midwest ISO also shall not be personally liable for any actions or omissions of others, including Owners, whose actions or omissions may relate to the Midwest ISO, or any property or property rights forming, or intended or believed to form, part of the Midwest ISO's property, or for any defect in the title to, or liens or encumbrances on, any such property or property rights.

Section 8.3. ***Indemnification.*** The Midwest ISO shall indemnify each Director, Officer, agent, employee, or other representative strictly in accordance with the terms and conditions of the Indemnification provisions of the Midwest ISO Agreement, Article II, Section VIII.

APPENDIX F

ARTICLE IX

AMENDMENTS

Section 9.1. ***Amendment.*** These Bylaws may be amended by the Board from time to time, subject to the receipt of all necessary federal and state regulatory approvals, and provided that no amendment is contrary to the Midwest ISO Agreement.

ARTICLE X

MISCELLANEOUS MATTERS

Section 10.1. ***Dispute Resolution.*** The Midwest ISO shall resolve disputes between and among the Midwest ISO and the Owners, individually or collectively, and Users other than the Owners, in accordance with the procedures set forth in Appendix D to the Midwest ISO Agreement. This provision does not apply to disputes covered under the Transmission Tariff.

Section 10.2. ***Inspection and Auditing Procedures.*** The Midwest ISO shall grant each Member, its employees or agents, external auditors, and federal and state regulatory authorities having jurisdiction over the Midwest ISO or an Owner, such access to the Midwest ISO's books and records as is necessary to verify compliance by the Midwest ISO with the Midwest ISO Agreement and to audit and verify transactions under the Midwest ISO Agreement. Such access shall be at reasonable times and under reasonable conditions. The Midwest ISO shall also comply with the reporting requirements of federal and state regulatory authorities having jurisdiction over the Midwest ISO with respect to the business aspects of its business operations, including, but not limited to, the State of Delaware. Contacts between Officers, employees, and agents of any Owner and those of the Midwest ISO pursuant to this Section 10.2 shall be strictly limited to the purposes of this Section 10.2 and shall comply with the Standards of Conduct set forth in Appendix A to the Midwest ISO Agreement.

ARTICLE XI

WITHDRAWAL OR TERMINATION OF MEMBERS

Section 11.1. ***Withdrawal Notice.*** A Member who is not an Owner may, upon submission of a written notice of withdrawal to the President, withdraw from membership in the Midwest ISO at any time, which withdrawal shall be effective thirty (30) days after the receipt of such notice by the President.

A Member who is also an Owner may withdraw under the procedures and rights specified in the Midwest ISO Agreement and shall be subject to the regulatory approvals referred to in that Agreement or as provided by applicable law. The effect of such withdrawal shall be as stated in that Agreement.

APPENDIX G

AGENCY AGREEMENT FOR OPEN ACCESS TRANSMISSION SERVICE OFFERED BY THE MIDWEST ISO FOR NONTRANSFERRED TRANSMISSION FACILITIES

Through this Agreement ("Agency Agreement"), the entity executing this Agency Agreement ("Transmission Owner"), allows the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") to offer and provide transmission service over certain facilities as detailed below.

RECITALS

A. A group of Owners will be filing or will have filed an Open Access Transmission Tariff ("Transmission Tariff") with the Federal Energy Regulatory Commission ("FERC") as part of a proposal for the Midwest ISO to become an Independent System Operator ("ISO"). Upon FERC approval and the transfer of those facilities in accordance with the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc., a Delaware Non-Stock Corporation ("Agreement"), the Midwest ISO will control certain transmission facilities, control of which will be transferred to it under Section 203 of the Federal Power Act, 16 U.S.C. § 824b. The Midwest ISO will offer to provide open access transmission service across those facilities. Through the Transmission Tariff, it is intended that the Midwest ISO also will offer to provide transmission service over other booked transmission facilities, control of which will <u>not</u> be transferred to the Midwest ISO under Section 203 of the Federal Power

Act as part of the initial filings. These other booked transmission facilities are the "Non-transferred Transmission Facilities."

B. The Owners are or will be members of the Midwest ISO. The Owners will or may maintain control of Non-transferred Transmission Facilities that are offered for service under the Midwest ISO Transmission Tariff.

C. In order for the Midwest ISO to offer service over Non-transferred Transmission Facilities, it is necessary that Owners provide the authority to the Midwest ISO to provide the transmission and other services necessary to effectuate the Transmission Tariff.

D. The Owners also will be entering into or will have entered into the Agreement which will detail the rights and responsibilities of the Owners, members and of the Midwest ISO.

E. Each Owner will enter into an Agency Agreement to authorize the Midwest ISO to act as its agent in the performance of its tariff administration duties with regard to Non-transferred Transmission Facilities; to commit Non-transferred Transmission Facilities and services as required for the performance of service agreements and of the Transmission Tariff; to arrange for dispute resolution; and for other purposes as specified herein and in the Agreement. This Agency Agreement pertains only to the Non-transferred Transmission Facilities and has no affect or bearing on service over any other transmission or other facilities.

APPENDIX G

TERMS OF AGREEMENT

1. Incorporation Of Transmission Tariff.

1.1 Incorporation Of Transmission Tariff Into Agreement.

The Transmission Tariff, including each and every constituent part, is incorporated into this Agency Agreement as though set forth herein in its entirety. In the event of any conflict between any provision of this Agency Agreement and the Transmission Tariff, the Transmission Tariff shall control.

2. Appointment Of Midwest ISO As Agent.

The Transmission Owner appoints the Midwest ISO as its agent to enter into service agreements in conformity with the Transmission Tariff on its behalf with regard to service involving Non-transferred Transmission Facilities. It is agreed that all such service agreements will bind the Transmission Owner to perform to the requirements and specifications of the Transmission Tariff and service agreements where appropriate.

3. Performance By Transmission Owner.

The Transmission Owner agrees to provide all services necessary or appropriate for performance under the Transmission Tariff and service agreements thereunder with regard to service involving Non-transferred Transmission Facilities. Upon the Midwest ISO's request, the Transmission Owner further agrees to provide the Midwest ISO with all information necessary or appropriate relating to the Non-transferred Transmission Facilities to permit or facilitate the Midwest ISO to perform its tariff administration functions under the Transmission Tariff and service agreements relating to such facilities.

4. Payment Of Transmission Owners.

The Midwest ISO shall distribute revenues associated with service under the Transmission Tariff among Transmission Providers in accordance with Appendix C to the Agreement.

5. Effectiveness, Duration Of Agency Agreement, and Withdrawal Rights.

The Agency Agreement is effective on the Transfer Date as defined in the Agreement unless the Owner withdraws from the Agreement before the Transfer Date. In that event, this Agency Agreement shall not become effective. The term of this Agency Agreement shall thereafter be coextensive with the duration of the Transmission Owner's participation as an Owner under the Agreement. The Transmission Owner's withdrawal rights and obligations associated with such withdrawal under this Agency Agreement shall be as set forth in the Agreement.

6. Liability And Indemnification.

The liability and indemnification provisions governing the Midwest ISO's liability to the Transmission Owner and any indemnification shall be the same as set forth in either the Transmission Tariff or the Agreement, whichever provision is applicable.

7. Dispute Resolution Procedures.

Any dispute between or among the Midwest ISO and the Transmission Owner shall be resolved in accordance with the Dispute Resolution Procedures of either the Transmission Tariff or the Agreement, whichever procedures are applicable.

APPENDIX G

8. Integration And Amendment.

This is an integrated agreement which contains all terms and conditions of agreement between the parties concerning the subject matter. Any prior or oral agreements concerning the subject matter not stated herein are superseded by this Agency Agreement. This Agency Agreement may be amended only by an executed writing.

9. Authority.

The Transmission Owner hereto represents that the person executing this agreement on its behalf is authorized to execute this agreement and bind such Transmission Owner to its terms, and that such authorization has been made in compliance with all applicable laws, articles of incorporation, bylaws, and resolutions and in a manner that the authorization is binding upon the Transmission Owner.

TRANSMISSION OWNER

Company: ______________________________

Signature: ____________________

Title: ____________________

Date: ____________________

APPENDIX H

TRANSMISSION SYSTEM FACILITIES

This Appendix provides the description and supporting documents for the Transmission System transferred to Midwest ISO for the purposes of planning and operation. In general, the criteria defining the Transmission System include:

1. All networked facilities above 100 kV.

2. All transformers whose two highest voltages qualify under the above voltage criteria.

3. All substation equipment that form the endpoints of the transmission lines in item 1, terminate the transformers in item 2, or provide voltage/stability control.

Each Transmission Owner provided, as a minimum, the following information on their facilities:

The descriptions of the transmission lines, including:

1. The names of the substations associated with a transmission line (the two endpoints for a two terminal line or the two endpoints and intermediate taps for multi-tapped lines).

2. The voltage level of each line.

3. Circuit maps containing each line or documents describing each line.

4. The mileage associated with each transmission line or tap section was optional and was provided by some Transmission Owners.

5. Ratings of each line were optional and were provided by some Transmission Owners.

APPENDIX H

Descriptions of the transformers meeting criteria 2 above, including:

1. Name of substation where transformer is located.

2. Voltage levels.

3. Number of windings (Optional).

4. Tap changing capabilities -- load and no load taps (Optional).

5. Ratings of each transformer were optional and were provided by some Transmission Owners.

If the map or circuit diagram provided by a Transmission Owner contained Non-transferred Transmission Facilities, these Non-transferred Transmission Facilities were marked out indicating that they were not included in the facilities to be controlled and planned by the Midwest ISO.

In cases of jointly owned facilities, there was an indication of the jointly owned facilities through symbols or specific notations.

Interconnections between transmission systems (Midwest ISO Transmission Owners and non-Midwest ISO Owners) are clearly marked on the system one-line drawings. The names or initials of the companies who own the facilities on each side of the interconnections are provided.

APPENDIX H

The following Transmission Owners provided descriptions of their Transmission System facilities:

1. Central Illinois Public Service Company (CIPSCo)
2. Cinergy
3. Commonwealth Edison Company (ComEd)
4. Hoosier Energy
5. Illinois Power Company
6. Kentucky Utilities (KU)
7. Louisville Gas & Electric Company (LG&E)
8. Union Electric Company (UE)
9. Wisconsin Electric Power Company (WEPCo)
10. Wabash Valley Power Association (WVPA)

APPENDIX I
INDEPENDENT TRANSMISSION COMPANIES

This Appendix sets forth a general framework for the development and operation of Independent Transmission Companies ("ITC's") within the Midwest ISO. Any conflict between Appendix I and other provisions of this Agreement or the Transmission Tariff shall be governed by the provisions of this Appendix. Under Appendix I, certain responsibilities which currently reside with the Midwest ISO may be assigned to an ITC, if it chooses to accept those responsibilities and if the Federal Energy Regulatory Commission ("FERC") acceptance or approval of the assignment is obtained as provided herein.

This Appendix I is intended to describe broad areas regarding the assignment of certain rights, responsibilities, and functions to an ITC. Any entity or entities submitting a proposal to become an ITC ("Filing Entity") shall submit a filing with FERC detailing each of the rights, responsibilities, and functions the ITC proposes to assume from the Midwest ISO together with specifics on implementing any of these assigned rights, responsibilities, and functions. The Filing Entity may do this through multiple filings as the ITC develops or through a single filing. Before submitting any filing to FERC, however, the Filing Entity shall provide details of the filing to the Midwest ISO at least thirty days before the filing date. In the filing to FERC, the Filing Entity shall demonstrate to FERC that the rights, responsibilities and functions proposed to be assigned to the ITC are appropriate by showing, among other things, that the proposed ITC's governance and structure assures independence of the ITC from any market participant and that the proposed ITC is of sufficient size and configuration to assume such rights, responsibilities, and functions appropriately. The Midwest ISO, its members, and others shall have the right to intervene, comment, or protest any such ITC filing or to file a complaint under Section 206 of the Federal Power Act with regard to any such ITC filing or document.

1. FERC APPROVAL

1.1 FERC Acceptance As A Prerequisite. Before receiving the rights and responsibilities provided for under this Appendix I, the Filing Entity shall apply for and receive a FERC order accepting the ITC proposal to be implemented and finding that the proposed ITC satisfies FERC's independence criteria and any other applicable criteria such that the entity may be treated as an ITC under this Appendix I.

1.2 Effect of FERC Acceptance. Once FERC issues an order accepting the filing and providing the finding required under Section 1.1, then the ITC may operate within the Midwest ISO consistent with the rights, responsibilities, and functions that have been accepted or approved by FERC.

1.3 Effect of FERC Denial. A Filing Entity which does not receive a FERC order finding satisfaction of FERC's independence and other applicable criteria shall be treated as an Owner under this Agreement once it executes the Agreement and Agency Agreement (if applicable). It shall not be considered an ITC eligible to assign the responsibilities detailed in this Appendix I until such time as it receives the necessary FERC order.

2. SECURITY COORDINATION

2.1 Regional Security Coordinator. The Midwest ISO shall be the regional security coordinator and shall perform the functions specified in Appendix E, Section V of this Agreement for all Midwest ISO transmission systems, including any ITC transmission systems.

2.2 ITC Actions. An ITC may take actions to preserve the security of the ITC system before requesting assistance from the Midwest ISO. The ITC shall inform the Midwest ISO of any such actions and coordinate such actions with the Midwest ISO.

2.3 Ultimate Authority. Notwithstanding any other provision in this Appendix I, the Midwest ISO may intercede and direct appropriate actions in its role as the regional security coordinator. If such Midwest ISO action is disputed, the Midwest ISO's position shall control pending resolution of the dispute.

3. BASE TRANSMISSION RATES

3.1 Right to File Rate Changes. The ITC shall possess the unilateral right, without receiving any Midwest ISO approval, to make filings at FERC proposing rate or rate structure changes (including incentive rate structures) involving base transmission charges for service to load within the ITC. Base transmission charges as used herein refer to the charges in Schedules 7, 8, and 9 of the Midwest ISO tariff or such other similar schedules used by the ITC. All other service to load outside the ITC is subject to the Midwest ISO base transmission charges. However, in the development of the "Drive-through" and "Drive-out" Midwest ISO rates, the ITC may submit inputs to the rate calculation for the ITC's facilities and costs which differ from the Midwest ISO rate formula that is part of the Transmission Tariff so long as the ITC has sought and received FERC authorization for the inclusion of such inputs in the Midwest ISO "Drive-through" and "Drive-out" transmission rates.

3.2 Limitations. The ITC may not unilaterally propose transmission rates to FERC that do not preserve revenues or payments due Midwest ISO Owners that are outside the ITC.

3.3 No Rate Pancaking. Notwithstanding its rights under Section 3.1, the ITC shall not implement rates or a rate structure which results in a transmission customer paying the ITC and the Midwest ISO more than one base transmission charge for any one transaction.

4. REVENUE DISTRIBUTION

4.1 ITC Receipt of Transmission Revenues. The ITC shall receive and/or retain revenues resulting from the provision of transmission service under the Tariff in accordance with Appendix C of this Agreement. The ITC may take no unilateral action which interferes with or affects the revenue distribution provided for in Appendix C of this Agreement or which interferes with the collection by the Midwest ISO of the revenues due it for services it provides or arranges. If the ITC receives revenues which other Owners or the Midwest ISO are entitled to receive, the ITC shall forward such revenues to the Owners or the Midwest ISO as soon as possible.

4.2 Redistribution of Revenues. The ITC may distribute the revenues due it in accordance with Appendix C of this Agreement in any manner it wishes subject to receiving any necessary regulatory approvals, without involvement of the Midwest ISO.

4.3 Funds Trust Agreement. The ITC shall agree to sign the Funds Trust Agreement, to be bound by all of its terms, and to make any and all payments or contributions required under the Funds Trust Agreement, and prior to the existence of any right of the ITC to receive revenues from transmission service under the Transmission Tariff shall execute the Funds Trust Agreement.

5. CONGESTION MANAGEMENT

5.1 ITC Congestion Management. Before filing any congestion management mechanism for constraints within the ITC, the ITC shall advise the Midwest ISO of its proposed filing, and both the ITC and the Midwest ISO shall use reasonable efforts to reach agreement on the filing. After a reasonable consultation process and even without agreement being reached, the ITC shall possess the right to file at FERC, without Midwest ISO approval, a mechanism for congestion management for constraints within the ITC.

5.2 Limitations. Any such ITC congestion management mechanism shall not operate in instances where its operation would cause a material adverse effect upon the Midwest ISO transmission system outside of the ITC or upon the users of that system. In addition, before the ITC congestion management mechanism becomes effective, the ITC and the Midwest ISO shall develop protocols detailing when the Midwest ISO and ITC congestion management mechanisms would operate. The ITC shall file such protocols with FERC and the protocols must be accepted or approved by FERC before the ITC congestion management mechanism becomes effective.

6. LOSSES

6.1 Right to File. The ITC shall possess the unilateral right to file at FERC, without any Midwest ISO approval, a mechanism for determining loss responsibility within the ITC, provided that this method does not affect the losses received by Transmission Owners and generators in areas outside of the ITC.

7. TARIFF ADMINISTRATION

7.1 Service under the Midwest ISO Tariff. Customers will receive transmission service under a single Midwest ISO Tariff which will apply to transmission service over the entire Midwest ISO (including the ITC), subject to changes to the Tariff accepted by FERC that the ITC may propose pursuant to this Appendix I. Customers will apply for service on the Midwest ISO OASIS. The Midwest ISO will execute the agreements with the customers for service and studies. The ITC shall make all decisions on rate discounts for ITC-only transactions.

7.2 Studies. If a system impact or other study is required to evaluate the ability of the ITC to provide the transmission service and the transaction is within the ITC, then the ITC shall possess the right to assume responsibility for the study, subject to coordination with the Midwest ISO. If a facilities study is required to study a constraint within the ITC, then the ITC shall possess the right to assume responsibility for the study in coordination with the Midwest ISO. With regard to such studies, the Midwest ISO shall administer the contracts with the customers and shall provide the notices and make the filings under the Transmission Tariff.

7.3 ATC. The Midwest ISO shall administer the ATC calculation in accordance with this Agreement and shall calculate CBM and TRM, provided that the ITC shall possess the unilateral right to provide the ratings, operating guides, and assumptions to be used in calculating ATC over the ITC facilities. If the Midwest ISO disagrees with these ratings, operating guides, or assumptions, the ITC's position shall prevail pending dispute resolution.

7.4 Scheduling. Customers will schedule through the processes established by the Midwest ISO. Scheduling protocols will be between the Midwest ISO and the control areas and/or the ITC.

8. CURTAILMENTS

8.1 ITC Responsibilities. For curtailments of transmission pursuant to the Tariff, if the curtailment involves a transaction within the ITC or is the result of a system problem or constraint within the ITC, then the ITC will have the first opportunity to address the need for or to carry out the curtailment of transactions within the ITC, subject to the Midwest ISO's authority to act as regional security coordinator. The ITC and the Midwest ISO shall develop protocols for the coordination of curtailments.

8.2 Midwest ISO Responsibilities. If the ITC is unsuccessful in addressing the curtailment as provided in Section 8.1, then the Midwest ISO shall assume responsibility for carrying out the curtailment provisions of the Tariff. In all circumstances other than those provided in Section 8.1, the Midwest ISO shall possess full responsibility for addressing the curtailment consistent with the Transmission Tariff and this Agreement.

9. OPERATIONS

9.1 Ratings and Operating Procedures. The ITC may establish ratings and operating procedures for its facilities subject to dispute resolution if the Midwest ISO disagrees. The ITC's position shall prevail pending dispute resolution.

9.2 Transmission Maintenance. The ITC may set its own transmission maintenance and outage schedules subject to dispute resolution if the Midwest ISO disagrees. The ITC shall coordinate such transmission maintenance and outage schedules with the Midwest ISO. With regard to such schedules, the ITC's position shall prevail during the dispute resolution process unless the Midwest ISO determines that system security is involved, in which case the Midwest ISO's determination shall prevail pending dispute resolution.

9.3 Generation Maintenance. The ITC may assume from the Midwest ISO the coordination of generator maintenance for generators within the ITC with regard to those generators which are required to coordinate maintenance pursuant to Appendix E, Section VII of this Agreement. The ITC shall inform the Midwest ISO of those maintenance activities.

9.4 Congestion Management and Must Run Units. The ITC may control congestion management consistent with Section V of this Appendix I and must run units to the extent permitted by FERC.

9.5 Temporary Operational Control. The Midwest ISO may assume temporary operational control over the ITC's facilities when required to return the Midwest ISO system to a secured state as required by its role as a regional security coordinator.

10. PLANNING

10.1 ITC Plan. The ITC may develop its plan for the construction of transmission facilities within the ITC. The ITC shall inform and provide a copy of its plan to the Midwest ISO as soon as it is available and shall coordinate with the Midwest ISO to the maximum extent practicable. Midwest ISO approval is not required for the ITC plan, subject to any dispute resolution as provided in Section 10.2 of this Appendix. Such ITC plan shall become part of the Midwest ISO regional plan, subject to Section 10.2. If the Midwest ISO believes that an ITC planned facility will have a material impact on facilities outside of the ITC which are located within the Midwest ISO, the ITC planned facility shall not be placed into operation until such time as the Midwest ISO has a reasonable time to review the ITC plan and any disputes are resolved.

10.2 Midwest ISO Disagreement. If the Midwest ISO disagrees with the ITC's plan, the Midwest ISO's disagreement with the plan will be resolved through dispute resolution.

10.3 Regional Planning. Nothing in this Section X is intended to change the responsibility of the Midwest ISO to develop a regional plan, including the ITC facilities, as provided in this Agreement.

APPENDIX I

11. BILLING AND REMITTANCE

11.1 ITC Responsibilities. For transactions occurring solely within the ITC or where the load is located within the ITC, the ITC possesses the right to perform the Midwest ISO billing, credit, and accounting responsibilities for those transactions.

11.2 Return of Revenues. If the ITC receives revenues which it is not entitled to receive pursuant to Appendix C of this Agreement, it shall as soon as possible remit those revenues to the Midwest ISO.

12. MONITORING AND PENALTIES

12.1 Midwest ISO Responsibilities. The Midwest ISO will continue to impose and collect penalties as currently provided in the Agreement and Tariff, and to perform the monitoring functions pursuant to this Agreement for transactions involving the ITC.

12.2 Exception. The ITC will be allowed to impose and collect penalties approved by FERC associated with its congestion management program so long as any such penalty does not cause an entity to be subjected to a penalty by both the Midwest ISO and the ITC for the same violation.

12.3 Monitoring and Assessment of ITC-Midwest ISO Relationship. The Midwest ISO shall monitor the ITC-Midwest ISO relationship to determine if the division of functions creates a competitive or reliability problem that affects the Midwest ISO's ability to provide reliable, non-discriminatory transmission service.

12.4 The Midwest ISO will monitor markets operating by an ITC.

13. LIABILITY

13.1 Assumption of Liability. The ITC shall assume all liabilities associated with its acts or omissions regarding those functions for which it has assume responsibility. The ITC shall indemnify and hold harmless the Midwest ISO for any and all liabilities associated with the ITC's actions.

14. DISPUTE RESOLUTION

14.1 Dispute resolution as used in this Appendix I refers to the dispute resolution procedures included as Appendix D to this Agreement, as it may be amended. The Midwest ISO shall consider whether any changes to its dispute resolution procedures need to be made to implement this Appendix I.

APPENDIX I

15. NOTIFICATION OF ASSUMPTION OF RESPONSIBILITIES

15.1 The ITC shall provide notice to the Midwest ISO of its election to assume the responsibilities described in Sections 7.2-7.4, 8.1, 9.1-9.4, 10.1, and 11.1 of this Appendix I. The ITC must provide notice to allow the Midwest ISO sufficient time to implement procedures to allow coordinated operation of the ITC together with the Midwest ISO.

16. OPERATING PROCEDURES AND PROTOCOLS

16.1 The ITC and the Midwest ISO shall cooperate and use their best efforts to develop the necessary operating procedures and protocols to allow timely start-up of the ITC pursuant to this Appendix I. Any disagreements shall be resolved pursuant to dispute resolution. Once such procedures and protocols have been developed, either through agreement or after dispute resolution, the Midwest ISO shall post such procedures and protocols on its website.

APPENDIX J

REVENUE DISTRIBUTION FOR SCHEDULE 18

I. **Additional Definitions.** Unless the context otherwise specifies or requires, the following additional definitions apply to this Appendix J, and, when used in this Appendix J, the following terms shall have the respective meanings set forth below.

A. **GridAmerica Companies.** The GridAmerica Companies are Ameren Services Company, as agent for its electric utility affiliates Union Electric Company d/b/a AmerenUE and Central Illinois Public Service Company d/b/a AmerenCIPS, America Transmission Systems, Incorporated, a subsidiary of FirstEnergy Corp., and Northern Indiana Public Service Company.

B. **Initial GridAmerica Companies.** The Initial GridAmerica Companies are America Transmission Systems, Incorporated, a subsidiary of FirstEnergy Corp., and Northern Indiana Public Service Company.

C. **Coordinating Owner.** Manitoba Hydro.

D. **Owners' and Coordinating Owner's Revenues.** Owners' and Coordinating Owner's Revenues are those revenues collected by the Midwest ISO from the GridAmerica Companies' zones pursuant to Schedule 18 for distribution to Owners, other than the GridAmerica Companies, and Coordinating Owner.

APPENDIX J

II. Revenue Distribution.

The Midwest ISO shall cause the distribution monthly of the Owners' and Coordinating Owner's Revenues associated with transmission services under Schedule 18 in accordance with this Appendix J and the Funds Trust Agreement. This Appendix J shall not apply to revenues collected under Schedule 18 by the Midwest ISO from zones other than the GridAmerica Companies' zones for distribution to the GridAmerica Companies. In order to cause the distribution of revenues on a monthly basis, the Midwest ISO may estimate the revenues to be received by each Owner and Coordinating Owner subject to a true-up. The following methodology is used to distribute revenues received associated with charges under Schedule 18:

Revenues shall be fully distributed to the Owners and Coordinating Owner based on each Owner's and Coordinating Owner's relative share of total lost revenues collected from GridAmerica Companies' zones, with those relative shares set out on Appendix J, Attachment 1. For this Section II, lost revenues collected from GridAmerica Companies' zones only reflect those test period revenues that would be eliminated because of the GridAmerica Companies joining the Midwest ISO.

III. Effective Date.

Appendix J will be effective on the first date that one of the GridAmerica Companies have their transmission facilities under the Transmission Tariff and charges under Schedule 18 begin.

APPENDIX J
ATTACHMENT 1

OWNERS' AND COORDINATING OWNER'S RELATIVE SHARE OF LOST REVENUES COLLECTED FROM THE GRIDAMERICA COMPANIES' ZONES UNDER SCHEDULE 18[1]

Transmission Owner	Lost Revenues (all GridAmerica Companies under the Transmission Tariff)	Percentage (all GridAmerica Companies under the Transmission Tariff)	Lost Revenues (Initial Grid-America Companies)	Percentages (Initial Grid-America Companies)
Alliant Energy West (IES Utilities and IPC)	$112,567	1.23%	$49,326	0.68%
American Transmission Company LLC	$137,592	1.50%	$77,790	1.07%
Central Illinois Light Co.	$62,938	0.69%	$19,280	0.27%
Cinergy Services, Inc.	$3,690,576	40.32%	$3,043,794	41.94%
City Water L&P, Springfield, Illinois	$36,288	0.40%	$4,993	0.07%
Hoosier Energy	$37,679	0.41%	$31,050	0.43%
International Transmission Company	$2,978,631	32.54%	$2,947,705	40.62%
Indianapolis Power & Light Company	$82,635	0.90%	$67,776	0.93%
LG&E Corporation	$874,381	9.55%	$563,469	7.76%
Manitoba Hydro	$104,529	1.14%	$59,410	0.82%
Michigan Electric Transmission Co. LLC	$87,183	0.95%	$72,772	1.00%
Minnesota Power, Inc.	$34,796	0.38%	$17,692	0.24%
Montana-Dakota Utilities Co.	$17,194	0.19%	$10,182	0.14%
Northern States Power Companies	$660,510	7.22%	$199,700	2.75%
Otter Tail Power Company	$23,736	0.26%	$13,062	0.18%
Southern Illinois Power Cooperative	$133,156	1.45%	$11,756	0.16%
Vectren	$79,909	0.87%	$67,587	0.93%
TOTAL	**$9,154,299**	**100.0%**	**$7,257,344**	**100.0%**

1 The percentages of total lost revenues collected from the GridAmerica Companies' zones pursuant to Schedule 18 resulting from the GridAmerica Companies having their transmission facilities under the Transmission Tariff shall be calculated for each Owner based upon the test period used to derive the charges under Schedule 18 of the Transmission Tariff. The percentages reflect all three GridAmerica Companies having their transmission facilities under the Transmission Tariff. For any month in which one or more GridAmerica Companies do not have their transmission facilities under the Transmission Tariff, the Lost Revenues and Percentages columns on the table would need to be revised to reflect only those GridAmerica Companies that do have their transmission facilities under the Transmission Tariff. For any month in which none of the GridAmerica Companies have their transmission facilities under the Transmission Tariff, Schedule 18 shall not apply and both the Lost Revenues and Percentage columns on the table would be zero for all Owners. In addition, if any of the Owners listed on the table withdraw from the Midwest ISO, upon the effectiveness of that withdrawal the Lost Revenues and Percentages columns on the table would need to be revised to reflect that withdrawal.

APPENDIX K

FILING RIGHTS PURSUANT TO SECTION 205 OF THE FEDERAL POWER ACT OF THE OWNERS AND THE MIDWEST ISO

The following represents the agreement of the Transmission Owners and the Midwest ISO on filing rights pursuant to section 205 of the Federal Power Act.

I. **Additional Definitions.** Unless the context otherwise specifies or requires, the following additional definitions apply to this Appendix K, and when used in this Appendix K, the following terms shall have the respective meanings set forth below.

A. **Appendix I Agreement.** One of the following agreements: (a) "Appendix I Agreement by and Between International Transmission Company and the Midwest Independent Transmission System Operator, Inc." dated August 31, 2001, as amended by the "Supplemental Agreement" by and among the Midwest Independent Transmission System Operator, Inc., International Transmission Company, and undersigned Owners dated November 15, 2001, as such agreement may be amended from time to time; (b) "Second Amended and Restated Appendix I ITC Agreement" by and between the Midwest ISO and GridAmerica LLC, dated as of May 30, 2003, as such agreement may be amended from time to time, and (c) any additional agreement that may be entered into by and between the Midwest ISO and a third party pursuant to Appendix I of the Agreement.

B. **Attachment O.** The rate formula set out in the Tariff, from Sheet No. 364 through 393, as may be amended from time to time.

C. **FPA.** The Federal Power Act, 16 U.S.C. § 824 et al.

D. **Grandfathered Agreements.** The agreements listed on Attachment P of the Transmission Tariff as that attachment may be changed from time to time.

E. **Non-Jurisdictional Transmission Owners.** Owners of transmission facilities that are not FERC public utilities, but over which service is provided by the Midwest ISO under the Transmission Tariff and who have transferred functional control of those facilities to the Midwest ISO.

F. **Parties.** The Transmission Owners and the Midwest ISO.

G. **Transmission Owner.** The owner of, and/or holder of FPA section 205 filing rights with respect to, transmission facilities, service over which is provided by the Midwest ISO under the Transmission Tariff and functional control over which has been transferred to the Midwest ISO, and who is a signatory to the Settlement Agreement Between Transmission Owners and Midwest ISO on Filing Rights, filed with FERC on November 30, 2004 in Docket Nos. RT01-87, ER02-106, and ER02-108. Only Transmission Owners that are public utilities under the FPA are included within this definition of Transmission Owner when the term is used to specify filing rights under FPA section 205.

II. Division Of Filing Rights

A. Transmission Revenue Requirements. Each Transmission Owner shall possess the full and exclusive right to submit filings under FPA section 205 with regard to its transmission revenue requirements. This full and exclusive right shall include the right to propose a new rate formula or any change to any component of any rate formula used to calculate its revenue requirements, if applicable, provided that such a change is related to that Transmission Owner's revenue requirements. A Transmission Owner shall not be required to follow the governance and coordination provisions of Articles III and IV of this Appendix K to exercise the filing right provided for in this Article II, Section A.

B. Attachment O. In order to change the Attachment O rate formula, the governance and coordination provisions of Articles III and IV of this Appendix K shall apply, provided that those Transmission Owners that do not have their revenue requirements calculated through such formula shall not have voting rights pursuant to Articles III and IV of this Appendix K with respect to such a change.

C. Zonal Rates.

1. Generally. The Transmission Owner(s) whose transmission facilities comprise the facilities within a zone shall possess the full and exclusive right to submit filings under FPA section 205 with regard to the transmission rate design for that zone for network load and transactions sinking within that zone; provided, however, that any filing made pursuant to this Article II, Section C, Paragraph 1 shall not in any way affect the rates charged or revenues collected in any other zone. Filings that may be made under this Article II, Section C, Paragraph 1 include, but are not limited to the following types of rate design changes: (1) changing from a formula rate to stated rates or vice-versa; (2) changing the form or type of formula rate; (3) proposing incentive rates; and (4) proposing performance-based rates. A Transmission Owner shall not be required to follow the governance and coordination provisions of Articles III and IV of this Appendix K to exercise the filing right provided for in this Article II, Section C, Paragraph 1.

2. **Multiple Transmission Owners Within a Zone.** If there are multiple Transmission Owners within a zone, those Transmission Owners should seek to reach agreement on a rate design. If no agreement is reached, then each Transmission Owner within the zone shall have the right to submit a FPA section 205 filing proposing an initial rate design or rate design change for the zone. A Transmission Owner shall not be required to follow the governance and coordination provisions of Articles III and IV of this Appendix K to exercise the filing right provided for in this Article II, Section C, Paragraph 2.

3. **Zone Boundaries.** For filings that propose to realign, eliminate, or otherwise reconfigure rate zones, only those Transmission Owners whose zones would be realigned, eliminated, or otherwise reconfigured by a filing shall possess the corresponding FPA section 205 rights. If there are multiple Transmission Owners whose rate zones would be realigned, eliminated, or otherwise reconfigured pursuant to a filing,

then all such Transmission Owners shall reach agreement before making a filing under this article. Transmission Owners shall not be required to follow the governance and coordination provisions of Articles III and IV of this Appendix K to exercise the filing right provided for in this Article II, Section C, Paragraph 3. Nothing in this Article II, Section C, Paragraph 3 is intended to modify, in any way, existing provisions and limitations applicable to zone boundary changes, including those included in Appendix C of the Agreement.

D. Rates Affecting More Than One Zone and Through and Out Rates.

Except as may be provided in Article II, Section E, Paragraph 2 of this Appendix K, the Transmission Owners shall possess the full and exclusive right to submit filings under FPA section 205 with regard to transmission rate design associated with rates affecting more than one zone as well as for transactions going through or out of the Midwest ISO. The filing right specified in this Article II, Section D shall be subject to the governance and coordination provisions of Articles III and IV of this Appendix K.

Limitations: Notwithstanding the foregoing, each Transmission Owner shall fully control its revenue requirement component used in calculating the total through and out rates set forth in Schedules 7 and 8 of the Transmission Tariff and in any other Transmission Tariff Schedule setting forth rates affecting more than one zone in which individual Transmission Owner revenue requirements are used to derive the rate.

E. <u>Transmission Upgrades and New Transmission Facilities</u>.

1. Each Transmission Owner shall possess the full and exclusive right under FPA section 205 to submit filings with regard to transmission upgrades and new transmission facilities that affect only the rates within the applicable Transmission Owner's Transmission Tariff zone(s). This provision applies to (a) a Transmission Owner constructing transmission upgrades or new transmission facilities in its own zone and seeking recovery of costs through rates that apply only to its zone; (b) a Transmission Owner constructing, or otherwise assuming financial responsibility for, transmission upgrades or new transmission facilities in a zone other than that Transmission Owner's zone and seeking recovery of costs through rates that apply only to its own zone; and (c) a Transmission Owner assigned costs associated with transmission upgrades or new transmission facilities and seeking recovery of costs through rates that apply only to its zone.

2. Both the Transmission Owners and the Midwest ISO shall possess the right to submit filings under FPA section 205 with regard to the allocation of costs associated with transmission upgrades and new transmission facilities affecting multiple Transmission Tariff zones; provided, however, that this filing right shall be subject to the governance provisions of Article III of this Appendix K with regard to filings made by Transmission Owners, and Article IV of this Appendix K with regard to filings made by either the Transmission Owners or the Midwest ISO.

F. **Retail Transmission**. Both the Transmission Owners and the Midwest ISO shall possess the right to submit filings under FPA section 205 with regard to revising the Transmission Tariff to include or change the terms or conditions applicable to transmission services for unbundled retail transmission customers. A Transmission Owner shall not be required to follow the governance and coordination provisions of Articles III and IV of this Appendix K to exercise the filing right provided for in this Article II, Section F; provided, however, that any such filing shall not materially affect any other Transmission Owner.

G. **Schedule 1 Costs**. Each Transmission Owner shall possess the full and exclusive right under FPA section 205 to submit its revenue requirements to be recovered under Schedule 1 of the Transmission Tariff. The Transmission Owners shall possess the full and exclusive right under FPA section 205 to submit changes in rates and rate design under Schedule 1 of the Transmission Tariff subject to the governance and coordination provisions of Articles III and IV of this Appendix K; provided, however, if a rate or rate design proposal affects only one zone, the Transmission Owner(s) in that zone may file under FPA section 205 without following the governance and coordination provisions of Articles III and IV of this Appendix K.

H. **Other Costs**. Each Transmission Owner shall possess the full and exclusive right under FPA section 205 to file a proposal or rate to recover other costs imposed on it and nothing in this Appendix K shall be interpreted as precluding any Transmission Owner from making a FPA section 205 filing to propose a method or rate for recovering any other cost the Transmission Owner may incur as a result of Midwest ISO actions (unless expressly dealt with herein in which case the specific provision would apply), provided that such costs are not otherwise recovered in rates. These other costs may include non-transmission costs such as the costs associated with implementing the Midwest ISO's directives with regard to preserving reliability or energy markets, including (but not limited to) directives pursuant to a Midwest ISO Transmission and Energy Markets Tariff (or successor document). A Transmission Owner shall not be required to follow the governance and coordination provisions of Articles III and IV of this Appendix K to exercise the filing right provided for in this Article II, Section H and shall, instead, have a full, exclusive, and unilateral right to submit any filing that only affects the rates within its zone(s); provided, however, that any proposal that requires loads in other zones to bear some or all of the costs shall be subject to Articles III and IV of this Appendix K.

I. **Ancillary Services Other Than Schedule 1.** Both Transmission Owners that own or control generation or other resources capable of providing ancillary services (offered to customers pursuant to the Transmission Tariff) and the Midwest ISO shall have the right to submit filings under FPA section 205 to govern the rates, terms, and conditions applicable to the provision of ancillary services. A Transmission Owner shall not be required to follow the governance and coordination provisions of Articles III and IV of this Appendix K to exercise the filing right provided for in this Article II, Section I; provided, however, that any ancillary service proposal with regional impacts shall be subject to the governance and coordination provisions of Articles III and IV of this Appendix K.

J. **Seams Agreements**. The Midwest ISO shall invite the participation of the Transmission Owners in any discussions with adjoining transmission providers or transmission owners, having as their purpose the consummation of a seams agreement containing provisions that could affect transmission revenues or impose costs or responsibilities on any or all of the Transmission Owners. The execution of agreements with adjoining transmission providers or owners shall be subject to the stakeholder review process provided for in the Agreement. The Midwest ISO shall take appropriate measures, consistent with its responsibilities under Article Three, Section D of the Agreement, to minimize the risk that any seams agreement will result in a net reduction in revenues recoverable by a Transmission Owner.

K. **Other Provisions Affecting Transmission Revenues**. With regard to any other tariff provision affecting transmission revenues, the Midwest ISO and the Transmission Owners shall each have filing rights under FPA section 205. The filing right specified in this Article II, Section K shall be subject to the limitations set forth in Article II, Section D above, and the governance and coordination provisions of Articles III and IV of this Appendix K.

L. Provisions Not Addressed in Article II, Sections A-K of this Appendix K. Except as provided herein, the Midwest ISO shall have the full and exclusive right to submit filings under FPA section 205 with regard to its Transmission Tariff and related documents; provided, however, that nothing herein shall prevent the Midwest ISO from inviting the participation of one or more Transmission Owners in any such submission; and provided further that nothing in this provision or Appendix K provides the Midwest ISO with any authority (other than that which it already may possess) to submit revisions to the Agreement or to any documents to which it is not a party.

III. TRANSMISSION OWNER GOVERNANCE ISSUES

A. FPA section 205 filings subject to this Article III, as provided for in Article II of this Appendix K, shall not be made by individual Transmission Owners. Instead, it is the intention of all Parties that Transmission Owners will coordinate the filing rights subject to this Article III through the development of joint filings of the type set forth herein. Decisions on whether or not to make a joint section 205 filing shall be made by majority vote, on a "one Transmission Owner – one vote" basis; provided that any entity that has one or more written delegations of authority to exercise section 205 rights on the matter that is the subject of a vote shall be authorized to cast a vote under each such delegation of authority. A minority of Transmission Owners may submit a filing under FPA section 205, provided the minority consists of at least three (3) Transmission Owners that either own or have been delegated authority to exercise section 205 rights concerning combined gross transmission plant of at least $2,500,000,000 as calculated based on the gross transmission plant reported by each Transmission Owner in its most recent FERC Form No. 1 filing (or equivalent data for Transmission Owners that do not file FERC Form No. 1 reports).

IV. COORDINATION

A. Transmission Owners Coordination. Transmission Owner(s), whether acting individually or jointly pursuant to Article III of this Appendix K, shall provide the Midwest ISO and all other Transmission Owners with at least thirty (30) days' notice before submitting any FPA section 205 filing that is subject to this Article IV as provided for in Article II of this Appendix K, unless circumstances require a shorter notice, in which case the Transmission Owner(s) shall use reasonable efforts to provide as much notice before the filing as possible. In the notice, the Transmission Owner(s) will use best efforts to provide as detailed a description of the filing and its rate impacts as possible. The Midwest ISO will circulate this information to its members, advisory committee, and state commission representatives. If the Midwest ISO believes it necessary, the Transmission Owner(s) will participate in a pre-filing meeting to discuss the filing and issues unless precluded by time exigencies.

B. Transmission Owners and Midwest ISO Coordination for Midwest ISO Filings. On any filing in which both the Midwest ISO and the Transmission Owners possess filing rights under FPA section 205 and which the Midwest ISO proposes to file, the Midwest ISO will provide advance notice to the Transmission Owners of at least thirty (30) days before making a filing under FPA section 205, unless circumstances require a shorter notice, in which case the Midwest ISO shall use reasonable efforts to provide as much notice before the filing as possible. In the notice, the Midwest ISO will use best efforts to provide as detailed a description of the filing and its rate impacts as possible. The Midwest ISO will circulate this information to its members, advisory committee, and state commission representatives. If the Transmission Owners believe it necessary, the Midwest ISO will participate in a pre-filing meeting to discuss the filing and issues unless precluded by time exigencies.

C. **<u>Transmission Owners and Midwest ISO Coordination</u>.** In instances in which both the Midwest ISO and the Transmission Owners in whole or in part intend to submit FPA section 205 filings on the same or similar subjects or tariff provisions, the Midwest ISO and the Transmission Owners shall meet to determine if a joint filing could be submitted. If the Midwest ISO and the Transmission Owners cannot agree to a joint filing, then separate filings may be submitted.

V. MISCELLANEOUS

A. **<u>Jurisdiction</u>.** Nothing in this Appendix K is intended to provide FERC with jurisdiction over Non-Jurisdictional Transmission Owners who may rely on the Midwest ISO to submit filings for them with regard to their individual revenue requirements or rate designs.

B. **<u>FPA Section 206 Rights</u>.** Nothing in this Appendix K is intended to limit or in any way abridge the rights of any Transmission Owner or the Midwest ISO to seek revisions to any document pursuant to FPA section 206. Moreover, nothing in this

Appendix K is intended to limit or in any way abridge the rights of any Transmission Owner or the Midwest ISO to intervene in any proceeding before FERC or to protest or comment upon any filing made with FERC.

C. **Appendix I of the Agreement.** Nothing in this Appendix K is intended to affect or in any way abridge the rights of Independent Transmission Companies under their respective Appendix I Agreement(s) and related agreements, as may be supplemented from time to time.

D. **Agreement and Transmission Revenue Distribution.** Nothing in this Appendix K is intended to modify or affect the filing rights of Transmission Owners and restrictions on such filing rights relating to the Agreement set forth in the Agreement or to provide the Midwest ISO with any filing rights with regard to transmission revenue distribution.

E. **Others' Filing Rights.** Nothing is this Appendix K is intended to affect the FPA section 205 filing rights of any entity which is not a Party. Nor is anything in this Appendix K intended to affect the procedural rights of any other interested party, including state regulatory commissions, regarding a filing submitted by the Midwest ISO or a Transmission Owner (or both) pursuant to Article II of this Appendix K.

F. **Midwest ISO Administration of Transmission Tariff.** Nothing in this Appendix K is intended to eliminate the Midwest ISO's responsibility for administering the Transmission Tariff in a prudent manner, consistent with the Agreement and FERC requirements. To that end, the Midwest ISO shall continue its administrative functions with regard to the Transmission Tariff in which, for example, it is responsible for ensuring that the formatting of the Transmission Tariff pages (including those pages submitted by Transmission Owners for advance Midwest ISO review pursuant to Article IV, Section A of this Appendix K) is in compliance with FERC requirements, and in which it remains the administrator of the Transmission Tariff even for Transmission Tariff provisions over which the Transmission Owners possess FPA section 205 filing rights under this Appendix K. In addition, nothing in this Appendix K is intended to affect the rights the Midwest ISO possesses to discount transmission service under the Transmission Tariff consistent with the provisions of this Appendix K. Additionally, nothing in this Appendix K forbids the Midwest ISO, if specifically authorized by a Transmission Owner or by multiple Transmission Owners, as appropriate, from making a filing on behalf of the Transmission Owner(s).

G. **Grandfathered Agreements**. Nothing in the Appendix K is intended to affect or modify whatever rights any entity may possess to seek modification of any Grandfathered Agreements.

H. **Appendix K Modifications**. It is the intent of the Parties that the provisions of this Appendix K, and the conforming changes to the Transmission Tariff and the Agreement required by this Appendix K, shall be subject to change solely by written amendment executed by the Midwest ISO and the Transmission Owners, with execution by the Transmission Owners requiring approval by a majority of the Transmission Owners provided, however, that any such amendment is not affirmatively opposed by three (3) or more Transmission Owners collectively owning gross transmission plant of at least $2,500,000,000 as calculated based on the gross transmission plant reported by each Transmission Owner in its most recent FERC Form No. 1 filing (or equivalent data for Transmission Owners that do not file FERC Form No. 1 reports). Otherwise, no Party may make a FPA section 205 filing that, if accepted or approved by FERC, would in any way have the effect of (1) canceling, modifying or limiting the FPA section 205 filing rights of any other Party provided for in this Appendix K, or (2) converting exclusive FPA section 205 filing rights of a Party provided for in this Appendix K into non-exclusive rights.

I. **<u>Mobile-Sierra Standard</u>.** It is the intent of the Parties that any change to any provision of this Appendix K, or to any conforming change to the Transmission Tariff or the Agreement, that is not proposed pursuant to Article V, Section H of this Appendix K whether proposed by a Party, non-Party, or the FERC shall be limited to the maximum extent permissible by law and shall be subject to the Mobile-Sierra public interest standard of review applicable to fixed rate agreements; provided, however, that beginning five years from the date of execution of the Settlement Agreement Between Transmission Owners and Midwest ISO on Filing Rights (filed at FERC on November 30, 2004 in Docket Nos. RT01-87, ER02-106, and ER02-108), actions initiated by the FERC, acting *sua sponte* pursuant to FPA section 206, shall be governed by the just and reasonable standard.

VI. TERM

This Appendix K shall remain in effect for 5 years from the date it becomes effective and shall remain in effect from year to year thereafter unless (a) it is deemed withdrawn pursuant Section 6.12 of the Settlement Agreement Between

Transmission Owners and Midwest ISO on Filing Rights (filed at FERC on November 30, 2004 in Docket Nos. RT01-87, ER02-106, and ER02-108) (referred to as "Filing Rights Settlement" for purposes of this Article VI, Section A), (b) it is withdrawn pursuant to a modification or amendment executed pursuant to Sections 6.8 and/or 6.9 of the Filing Rights Settlement, or (c) three-fourths of the Transmission Owners then subject to this Appendix K give one year advance notice in writing that they wish to terminate this Appendix K; provided, however, that unless expressly stated otherwise, this Appendix K shall not be deemed withdrawn if modified or amended under Sections 6.8 and/or 6.9 of the Filing Rights Settlement; and provided further that a Transmission Owner shall not be subject to, or otherwise bound by, this Appendix K at any time following its effective withdrawal from either the Agreement or an Appendix I Agreement.

96 FERC ¶ 62,256

UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

UtiliCorp United Inc. Docket No. EC01-142-000

ORDER AUTHORIZING DISPOSITION
OF JURISDICTIONAL FACILITIES

(Issued September 13, 2001)

On August 20, 2001, UtiliCorp United Inc. (UtiliCorp) filed an application pursuant to section 203 of the Federal Power Act (FPA) [1] requesting Commission authorization to transfer operational control of certain of UtiliCorp's jurisdictional transmission facilities to the Midwest Independent System Operator, Inc. (Midwest ISO). The jurisdictional transmission facilities involved include Missouri Public Service, St. Joseph Light and Power and WestPlains Energy-Kansas divisions.

UtiliCorp, an international energy and services company, participates in both regulated and non-regulated activities and serves electric and gas utility customers in Missouri, Kansas, Iowa, Nebraska, Colorado, Michigan and Minnesota through six utility divisions. UtiliCorp is also an energy marketer through its current subsidiary, Aquila Energy Marketing Corporation.

On January 15, 1998, a group of public utilities jointly filed an application pursuant to section 203 of the FPA to transfer operational control over certain of their jurisdictional transmission facilities to the Midwest ISO, pursuant to the Agreement of Transmission Facilities Owners to Organize the Midwest Transmission System Operator, Inc. [2] By order dated September 16, 1998, the Commission approved the public utilities'

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[1]16 U.S.C. § 824b (1994).

[2]The public utilities at that time included the Cincinnati Gas & Electric Company, Commonwealth Edison Company, Commonwealth Edison Company of Indiana, Illinois Power Company, PSI Energy, Inc., Wisconsin Electric Power Company, Union Electtric Company, Central Illinois Public Service Company, Louisville Gas & Electric Company, and Kentucky Utilities Company.

section 203 application subject to certain conditions. [3] In Order No. 2000, [4] the Commission also held that any public utility seeking to transfer control of its transmission facilities to an RTO must file an application under section 203 for approval.

According to the application, the proposed transfer is consistent with the public interest and will not have an adverse effect on competition, rates or regulation. With respect to competition, UtiliCorp states that the proposed transfer will have no effect on generation market power and will not result in higher generation market prices or reduced output in electricity markets. With regard to rates, UtiliCorp states that proposed transfer will have a beneficial effect on ratepayers and transmission customers because the proposed transfer will expand the region over which sellers and buyers can transmit power at non-pancaked rates. With respect to regulation, UtiliCorp states that UtiliCorp and Midwest ISO will continue to be regulated by the Commission. In addition, UtiliCorp states that the Missouri and Kansas commissions will have the opportunity to review and must approve the proposed transfer.

Notice of the application was published in the Federal Register, with motions to intervene or protests due on or before September 10, 2001. None were received.

After consideration, it is concluded that the proposed transfer of operational control over specified jurisdictional transmission facilities from UtiliCorp to the Midwest ISO is consistent with the public interest and is authorized, subject to the following conditions:

(1) The proposed transfer is authorized upon the terms and conditions and for the purposes set forth in the application;

(2) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service,

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[3]Midwest Independent Transmission System Operator, Inc., et al., 84 FERC ¶ 61,231, order on rehearing, 85 FERC ¶ 61,372 (1998).

[4]Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), petitions for review pending sub nom., Public Utility District No. 1 of Snohomish County, Washington v. FERC, Nos. 00-1174, et al. (D.C. Cir.).

accounts, valuation, estimates or determinations of costs or any other matter whatsoever now pending or which may come before the Commission;

(3) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted;

(4) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate;

(5) The proposed transfer is subject to the same conditions imposed on the other Midwest ISO public utilities in Docket Nos. ER98-1438-000 and EC98-24-000; and

(6) UtiliCorp shall promptly notify the Commission of the date on which the disposition of jurisdictional facilities has been consummated.

Authority to act on this matter is delegated to the Director, Division of Tariffs and Rates - West, pursuant to 18 C.F.R. § 375.307. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within thirty (30) days of the date of the issuance of this order, pursuant to 18 C.F.R. § 385.713.

Michael A. Coleman
Director
Division of Tariffs and Rates - West

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JUN 4 2003
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97 FERC ¶ 62, 231
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

UtiliCorp United Inc. Docket No. EC02-24-000

ORDER AUTHORIZING DISPOSITION
OF JURISDICTIONAL FACILITIES

(Issued December 13, 2001)

On November 14, 2001, UtiliCorp United Inc. (UtiliCorp) filed an application pursuant to section 203 of the Federal Power Act (FPA) [1] requesting Commission authorization to transfer operational control of certain of UtiliCorp's jurisdictional transmission facilities to the Midwest Independent System Operator, Inc. (Midwest ISO). The jurisdictional transmission facilities involved include those transmission facilities of Missouri Public Service, St. Joseph Light and Power and WestPlains Energy-Kansas divisions that were omitted from the list of facilities to be transferred to Midwest ISO in Docket No. EC01-142-000. [2]

UtiliCorp, an international energy and services company, participates in both regulated and non-regulated activities and serves electric and gas utility customers in Missouri, Kansas, Iowa, Nebraska, Colorado, Michigan and Minnesota through six utility divisions. UtiliCorp is also an energy marketer through its current subsidiary, Aquila Energy Marketing Corporation.

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[1] 16 U.S.C. § 824b (1994).

[2] On September 13, 2001, the Commission authorized UtiliCorp to transfer control over certain transmission facilities of Missouri Public Service, St. Joseph Light, and WestPlains Energy-Kansas divisions to Midwest ISO. See, 96 FERC ¶ 62,256 (2001).

On January 15, 1998, a group of public utilities jointly filed an application pursuant to section 203 of the FPA to transfer operational control over certain of their jurisdictional transmission facilities to the Midwest ISO, pursuant to the Agreement of Transmission Facilities Owners to Organize the Midwest Transmission System Operator, Inc.[3] By order dated September 16, 1998, the Commission approved the public utilities' section 203 application subject to certain conditions.[4] In Order No. 2000,[5] the Commission also held that any public utility seeking to transfer control of its transmission facilities to an RTO must file an application under section 203 for approval.

According to the application, the proposed transfer is consistent with the public interest and will not have an adverse effect on competition, rates or regulation. With respect to competition, UtiliCorp states that the proposed transfer will have no effect on generation market power and will not result in higher generation market prices or reduced output in electricity markets. With regard to rates, UtiliCorp states that proposed transfer will have a beneficial effect on ratepayers and transmission customers because the proposed transfer will expand the region over which sellers and buyers can transmit power at non-pancaked rates. With respect to regulation, UtiliCorp states that UtiliCorp and Midwest ISO will continue to be regulated by the Commission. In addition, UtiliCorp states that the Missouri and Kansas commissions will have the opportunity to review and must approve the proposed transfer.

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[3]The public utilities at that time included the Cincinnati Gas & Electric Company, Commonwealth Edison Company, Commonwealth Edison Company of Indiana, Illinois Power Company, PSI Energy, Inc., Wisconsin Electric Power Company, Union Electric Company, Central Illinois Public Service Company, Louisville Gas & Electric Company, and Kentucky Utilities Company.

[4]Midwest Independent Transmission System Operator, Inc., et al., 84 FERC ¶ 61,231, order on rehearing, 85 FERC ¶ 61,372 (1998).

[5]Regional Transmission Organizations, Order No. 2000, 65 Fed. Reg. 809 (January 6, 2000), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 ¶ 31,089 (1999), order on reh'g, Order No. 2000-A, 65 Fed. Reg. 12,088 (March 8, 2000), FERC Statutes and Regulations, Regulations Preambles July 1996-December 2000 ¶ 31,092 (2000), petitions for review dismissed, Public Utility District No. 1 of Snohomish County, Washington v. FERC, Nos. 00-1174, et al. (D.C. Cir.)(issued December 11, 2001).

Notice of the application was published in the Federal Register, with motions to intervene or protests due on or before December 5, 2001. None were received.

After consideration, it is concluded that the proposed transfer of operational control over specified jurisdictional transmission facilities from UtiliCorp to the Midwest ISO is consistent with the public interest and is authorized, subject to the following conditions:

(1) The proposed transfer is authorized upon the terms and conditions and for the purposes set forth in the application;

(2) The foregoing authorization is without prejudice to the authority of the Commission or any other regulatory body with respect to rates, service, accounts, valuation, estimates or determinations of costs or any other matter whatsoever now pending or which may come before the Commission;

(3) Nothing in this order shall be construed to imply acquiescence in any estimate or determination of cost or any valuation of property claimed or asserted;

(4) The Commission retains authority under sections 203(b) and 309 of the FPA to issue supplemental orders as appropriate;

(5) The proposed transfer is subject to the same conditions imposed on the other Midwest ISO public utilities in Docket Nos. ER98-1438-000 and EC98-24-000; and

(6) UtiliCorp shall promptly notify the Commission of the date on which the disposition of jurisdictional facilities has been consummated.

Authority to act on this matter is delegated to the Director, Division of Tariffs and Rates - West, pursuant to 18 C.F.R. § 375.307. This order constitutes final agency action. Requests for rehearing by the Commission may be filed within thirty (30) days of the date of the issuance of this order, pursuant to 18 C.F.R. § 385.713.

Michael A. Coleman

Director
Division of Tariffs and Rates - West

INTERNATIONAL
Schedule DO-3

RTO Cost-Benefit Analysis

Aquila Missouri Electric Utility Operations

Prepared By:

CRA International

March 28, 2007

TABLE OF CONTENTS

1. EXECUTIVE SUMMARY

1.1. INTRODUCTION

CRA International ("CRA") has conducted a cost-benefit analysis for the Aquila Missouri electric utility operations (collectively, Missouri Public Service and St. Joseph's Light and Power) to assess the impact of potential membership in a Regional Transmission Organization ("RTO"). Other investor-owned utilities with service territories in Missouri[1] are currently members of one of two different RTOs: 1) the Midwest Independent System Operator ("Midwest ISO")[2] and 2) the Southwest Power Pool ("SPP RTO")[3]. As such, the Aquila Missouri companies asked CRA to evaluate the costs and benefits that would accrue to the utility and its customers if Aquila Missouri were to join one of these two RTOs.

Currently, Aquila Missouri has a number of its transmission- and reliability-related functions performed by SPP and the Midwest ISO. Aquila Missouri is a transmission owner under the SPP tariff, and the Midwest ISO is the reliability coordinator for Aquila Missouri. While the potential exists for Aquila Missouri to continue this type of relationship with the two RTOs in the near future, this interim-type status is unlikely to be available over the long-term. As such, in this study it is assumed that Aquila Missouri will need to move to full market membership in the Midwest ISO or in the SPP RTO or to move to a "Stand-alone" status in which it performs (or procures) its transmission- and reliability-related functions on its own.[4]

1 These Missouri utilities include AmerenUE, a member of the Midwest ISO, and Kansas City Power and Light ("KCP&L") and Empire District, members of the SPP RTO. Aquila Missouri is directly interconnected with the Midwest ISO through AmerenUE, and with the SPP RTO through KCP&L and Westar Energy. During the course of the preparation of this study, Aquila announced a transaction under which Great Plains Energy, the parent of KCP&L, would become the parent of Aquila. Potential impacts of this transaction on the cost-benefit results have not been considered in this study.

2 The Midwest ISO covers all or part of the Canadian province of Manitoba and 15 Midwestern states, including portions of Missouri and the neighboring states of Iowa and Illinois. The market operated by the Midwest ISO provides a security-constrained unit commitment reflecting the marginal cost of providing for transmission losses, and operates a day-ahead market, a real-time market, and a financial transmission rights market.

3 SPP was originally formed as a reliability council, and covers all or parts of eight south central states, including Missouri and the neighboring states of Arkansas, Kansas, and Oklahoma. Most, but not all, of the load-serving entities in the SPP reliability region are currently members of the market operated by the SPP RTO. The SPP RTO began operation of a real-time market on February 1, 2007.

4 Aquila Missouri is a longstanding member of the SPP reliability council. For purposes of this study, Aquila Missouri is assumed to remain in the SPP reliability council in all cases, and thus would continue to pay the SPP annual membership fee and its allocated share of SPP's NERC assessment.

As discussed in further detail below, we have found that joining an RTO is expected to provide net benefits to Aquila Missouri. Subject to certain qualitative considerations and modeling assumptions, we have also found joining the SPP RTO to be more beneficial to Aquila Missouri than joining the Midwest ISO.

1.2. METHODOLOGY

The time horizon for this study is the 10-year period from 2008 through 2017. CRA has performed GE MAPS model runs for this period assuming Aquila Missouri is: 1) Stand-alone, 2) a member of the Midwest ISO, or 3) a member of the SPP RTO. GE MAPS is a detailed economic dispatch and production cost model that simulates the operation of the electric power system taking into account transmission topology. The model determines the security-constrained commitment and hourly dispatch of each modeled generating unit, the loading of each element in the transmission system, and the locational marginal price ("LMP") for each generator and load area. The GE MAPS model was recently used by CRA to support the U.S. Department of Energy in conducting the August 2006 National Electric Transmission Congestion Study required by the Energy Policy Act of 2005.

In comparison to the Stand-alone case, the two RTO cases are modeled in GE MAPS with Aquila Missouri: 1) having no wheeling charges for transactions with fellow RTO members, 2) committing its generating units efficiently through an RTO-wide regional optimization process, and 3) operating flowgates at higher capacity levels through market-based RTO congestion management. These factors serve to decrease impediments to Aquila Missouri trade in the RTO cases and thus yield "trade benefits" to Aquila Missouri. In this study, trade benefits are measured as the decrease in the total cost to serve Aquila Missouri load (Aquila Missouri production costs for owned and contracted capacity plus purchased power costs minus "off-system" sales revenue).[5] These trade benefits must be compared to the additional administrative charges that Aquila Missouri would incur by being a member of an RTO.

1.2.1. Midwest ISO and SPP RTO Modeling

Currently, the Midwest ISO and SPP RTO markets are in different stages of development. The Midwest ISO has in operation a real-time market, a day-ahead market, and financial transmission rights ("FTRs"). In addition, the Midwest ISO has formal plans and budgeting to

5 Fixed costs that do not change between cases, such as depreciation for owned-generating units are not included in this measure. The cost to serve Aquila Missouri load has not been further separated between wholesale and retail jurisdiction in this study.

institute an ancillary services market. The Midwest ISO projects total administrative costs of roughly 36 cents per MWh of market member net energy for load over the next few years.[6]

The SPP RTO commenced operation of a real-time market on February 1, 2007. Subject to cost-benefit consideration, the SPP RTO is evaluating plans to move ahead with establishing a day-ahead market, financial transmission rights and an ancillary services market. Before consideration of these additional market developments, the SPP RTO projects administrative costs over the next few years that are approximately 20% lower per MWh of market member net energy for load than that of the Midwest ISO.

The costs and benefits of RTO market development require formal and complex study and evaluation. It is anticipated that the SPP RTO will institute additional market development if cost-benefit studies indicate that the projected benefits exceed the costs. Such analyses are beyond the scope of the type of study that can be easily performed on behalf of a non-RTO utility such as Aquila Missouri.

As such, for purposes of this cost-benefit study, it is assumed that the SPP RTO market will be similar in overall design to that of the Midwest ISO over the long-term time frame evaluated in this study. While it is unlikely that SPP would implement by 2008 the additional market developments in place at the Midwest ISO, the administrative charges charged to SPP RTO members likely will be lower than those charged to Midwest ISO members until such time as the markets become similar in design.

We have further assumed that, under base conditions, the SPP RTO administrative charges per MWh including incorporation of these additional market developments will be similar to those projected by the Midwest ISO. PJM, an RTO with markets in place similar to those of the Midwest ISO, projects administrative charges per MWh of member load similar to those projected by the Midwest ISO. With market development comparable to that of the Midwest ISO, SPP estimates, on a preliminary basis, administrative charges per MWh of market member load in roughly the same range as the Midwest ISO. SPP is currently significantly smaller in terms of market member load than the Midwest ISO and PJM. All else equal, the resulting reduction in economies of scale in operations could result in SPP administrative costs per MWh, with a comparable level of market development, being higher than those incurred by the Midwest ISO and PJM.

6 Administrative charges per MWh of net energy for the load of RTO market members is used in this study as a reasonable approximation for determining Aquila Missouri's administrative charges if a member of an RTO market. In practice, the RTO administrative charges are assessed using a variety of metrics. Market member load distinguishes between members participating in the RTO markets from those that are solely reliability members.

1.3. FINDINGS

1.3.1. Net Benefits of Joining an RTO

As shown in Table 1, the quantitative findings indicate a net benefit to Aquila Missouri in joining an RTO relative to Stand-alone operations. The results are the mid-2007 present value of net benefits over the 2008 to 2017 period.[7]

Table 1
2008-2017 Benefits (Costs) to Aquila Missouri of RTO Membership in comparison to Stand-alone Status
(in millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Trade Benefits: Decrease in Cost to Serve Aquila Missouri Load	29.9	95.7
Savings from RTO Providing Reliability/Transmission Functions	16.0	16.0
RTO Administrative Charges	(23.5)	(23.5)
FERC Charges	(1.3)	(1.3)
Total Benefits (Costs)	**21.1**	**86.9**

As shown in Table 1, the trade benefits of joining an RTO, i.e., the savings in the net cost to serve Aquila Missouri load, are positive and range from $30 to $96 million over the 10-year study period. The savings that Aquila incurs by having the RTO perform transmission and reliability functions rather than performing or procuring these functions on a Stand-alone basis are $16.0 million over the 10-year study period. The administrative charges that Aquila would incur for being a member of the RTO market are $23.5 million over the 10-year study period. This is an additional cost and thus is shown as a negative benefit in Table 1. And finally, the charges paid to FERC that Aquila would be assessed as a member of an RTO would be $1.3 million higher than if Aquila were Stand-alone over the study period.

The overall net benefit to Aquila of RTO membership is projected to be $21 to $87 million over the 10-year study period. In addition, the annual net benefits are projected to be positive for each year of the study period.[8]

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7 GE MAPS runs were performed for the calendar years 2008, 2012 and 2017 with results for intervening years interpolated. A present value rate of 8.0% was applied, consistent with Aquila Missouri's after-tax cost of capital. An underlying inflation rate of 2.5% was assumed.

8 These quantitative results are a projection based on a number of modeling assumptions that in practice will deviate from the estimates used herein. As such, the results should be viewed as indicative of the direction of the net benefits rather than a specific computation of the precise level of net benefits that will incur with RTO entry.

A key risk factor in joining an RTO is the amount of RTO administrative charges that could be incurred. However, even if the $23.5 million of RTO administrative charges shown in Table 1 increased by 50% from those projected in this study, there would still be considerable benefits for Aquila Missouri joining an RTO. Moreover, qualitative considerations for factors not directly addressed in the quantitative modeling, such as increased price transparency and reduced reliance on Transmission Loading Relief ("TLR") events as a member of an RTO, provide further support for the benefits of Aquila Missouri joining an RTO.

1.3.2. Net Benefits of Joining the Midwest ISO or the SPP RTO

With respect to whether it would be more economic to join the Midwest ISO or the SPP RTO, the quantitative results in Table 1 indicate a $66 million greater benefit for Aquila Missouri being a member of the SPP RTO. As noted above, this benefit is premised on the SPP RTO having in place additional market development that it does not yet have in place, and operating these markets at costs comparable to the Midwest ISO.[9]

The greater benefits for membership in the SPP RTO appear to be primarily the result of Aquila Missouri's location and the nature of its transmission inter-ties with adjoining control areas. Aquila Missouri is located on the western side of Missouri and is heavily interconnected with KCP&L in particular. The total tie-line capacity in MVA on the transmission lines that interconnect Aquila Missouri with SPP RTO members (KCP&L and Westar Energy) is more than five times as large as the capacity on the tie-lines that interconnect Aquila Missouri with Midwest ISO market members (AmerenUE).[10]

Moreover, regardless of Aquila Missouri status (Stand-alone, in the Midwest ISO, or in the SPP RTO) the magnitude of the Aquila Missouri power flow to and from the SPP RTO over the tie-lines in the GE MAPS model runs is significantly higher than that to and from Midwest ISO market members. These physical inter-ties between Aquila Missouri and the SPP RTO exist regardless of whether Aquila Missouri is in the SPP RTO or the Midwest ISO. However, placing cost impediments (e.g., wheeling charges for transactions between Aquila and the SPP RTO) on these inter-ties, as would be the case if Aquila Missouri were in the Midwest ISO, provides a substantial impediment to Aquila Missouri trade.

As a result, the GE MAPS runs indicate that Aquila Missouri is able to displace control area generation, particularly gas-fired generation, with less expensive market purchases to a greater extent in the SPP RTO case. As shown in Table 2, Aquila Missouri generation, which

9 A high natural gas price sensitivity analysis was performed for the year 2012, and indicated that with higher gas prices, the net benefits to Aquila from joining an RTO would increase, and the net benefits of joining the SPP RTO would increase more in dollar terms than the benefits of joining the Midwest ISO.

10 NERC Multi-regional Modeling Working Group ("MMWG") 2005 series 2010 summer peak loadflow.

is roughly equal to Aquila Missouri load in the Stand-alone case, is reduced in the RTO cases, but is reduced significantly more in the SPP RTO case.[11]

Table 2
Decrease in Aquila Missouri Generation in RTO in comparison to Stand-alone Status

	Decrease in Generation (GWh)			Decrease as Share of Net Aquila Load		
	2008	2012	2017	2008	2012	2017
In Midwest ISO	94	258	381	1%	3%	3%
In SPP RTO	1,324	2,173	2,562	15%	22%	23%

Table 2 indicates that additional economic purchases are displacing Aquila Missouri generation in the SPP RTO case through the unit commitment process and through the elimination of wheeling charges with SPP RTO members, and thereby providing additional net benefits. In particular, the gas-fired Aries combined-cycle unit is committed and generates significantly more often in the Stand-alone and Midwest ISO cases than in the SPP RTO case.[12]

Given the smaller size, in terms of market member load, of the SPP RTO, economies of scale could result in higher administrative costs per MWh for the SPP RTO with further market development. However, given the differences in Aquila Missouri net benefits found in the MAPS modeling, even a 50% greater administrative charges per MWh for the SPP RTO would not alter the quantitative advantage found in this study for Aquila Missouri being a member of the SPP RTO.

Again, however, the SPP RTO does not yet have the same level of RTO market development as the Midwest ISO and as modeled in this study. As such, uncertainty exists as to the timing of any future SPP RTO market developments and the costs that would be incurred in putting in place those developments.

11 Aquila Missouri generation as used here includes generation in the Aquila Missouri control area including the merchant Aries unit, plus Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area.

12 The Aries generation is assumed to be purchased by Aquila Missouri at prevailing market prices in all cases. The 580 MW Aries unit owned by Calpine was auctioned to Kelson Energy for $235 million in December 2006 over Aquila Missouri's competing bid of $230 million. To the extent that Aries output becomes contracted to entities outside of the Aquila Missouri control area, Aquila Missouri likely would need to make additional purchases and/or commit and generate more energy from the gas-fired South Harper peaking unit or other units. The additional amount needed would be greater in the Stand-alone and Midwest ISO cases and likely would further increase the relative benefit of joining the SPP RTO.

2. ANALYTIC FRAMEWORK

In this study, it is assumed that Aquila Missouri will need to move to full market membership in the Midwest ISO or in the SPP RTO or to move to a "Stand-alone" status in which it performs (or procures) its transmission- and reliability-related functions on its own.

2.1. CASES ANALYZED

CRA modeled three alternative cases for Aquila Missouri in this study:

- **Stand-alone case.** Aquila Missouri does not join an RTO, and performs (or procures) its transmission- and reliability-related functions on its own.
- **RTO Cases:**
    1. **Midwest ISO case.** Aquila Missouri joins the Midwest ISO as a full member of the RTO participating in all markets and paying all applicable administrative costs.
    2. **SPP RTO case.** Aquila Missouri joins the SPP RTO as a full member of the RTO participating in all markets and paying all applicable administrative costs.

In this study, the Stand-alone case is used as the reference case from which changes in costs and benefits are measured. Aquila Missouri is a longstanding member of the SPP reliability council. For purposes of this study, Aquila Missouri is assumed to remain in the SPP reliability council in all cases, and thus would continue to pay the SPP annual membership fee and its allocated share of SPP's NERC assessment.

2.2. COSTS AND BENEFITS

The evaluation of the costs and benefits has two basic components:

- **Trade benefits,** which are estimated using energy modeling to obtain the Aquila Missouri cost to supply its load under each case. The energy market simulation uses General Electric's MAPS tool.
- **Administrative costs**, the Aquila Missouri costs to perform transmission-related functions on its own or alternatively to pay administrative charges to the Midwest ISO or SPP RTO and interface with the RTOs.

The time horizon for the study consists of the 10-year period from 2008 through 2017. Detailed energy model simulations were performed for 2008, 2012 and 2017, and interpolation was used to obtain energy modeling results for the other years in the study horizon.[13] A natural gas price sensitivity is performed for the year 2012 only.

2.3. Midwest ISO and SPP RTO Markets

For purposes of this cost-benefit study, it is assumed that the SPP RTO market will be similar in overall design to that of the Midwest ISO over the long-term time frame used in this study Currently the Midwest ISO and SPP RTO are in different stages of market development. The Midwest ISO has in operation a real-time market, a day-ahead market, and financial transmission rights (FTRs). In addition, the Midwest ISO has formal plans and budgeting to institute an ancillary services market. The Midwest ISO had not yet formalized plans for the formation of a capacity market. The Midwest ISO projects total administrative costs of roughly 36 cents per MWh of market member load over the next few years.[14]

The SPP RTO commenced operation of a real-time market on February 1, 2007. Subject to cost-benefit consideration, the SPP RTO is evaluating plans to move ahead with establishing a day-ahead market, financial transmission rights and an ancillary services market. Before consideration of these additional market developments, the SPP RTO projects administrative costs per MWh of market member load roughly 20% below that of the Midwest ISO.

The costs and benefits of RTO market development require formal and complex study and consideration. It is anticipated that the SPP will institute additional market development if cost-benefit studies indicate that the projected benefits exceed the costs. Such analyses are beyond the scope of the type of study easily performed on behalf of a non-RTO utility such as Aquila Missouri. While it is unlikely that SPP would implement the additional market developments instituted by the Midwest ISO by 2008, the administrative charges charged to SPP RTO members likely will be lower than those charged to Midwest ISO members until such time as the markets become similar in design. We will further consider the ramifications of this assumption in subsequent sections.

3. ENERGY MODELING

The energy modeling in this study was performed using General Electric's MAPS tool. GE MAPS is a detailed economic dispatch and production costing model that simulates the operation of the electric power system taking into account transmission topology. The GE MAPS model determines the security-constrained commitment and hourly dispatch of each

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13 The results for the intervening years were interpolated on a straight-line basis using the MAPS results in 2005 dollars, and then an annual inflation rate of 2.5% was applied.

14 Midwest ISO, Recommended Capital and Operating Budget, Section IV, Projected Average Administrative Cost per MWH, December 14, 2006.

modeled generating unit, the loading of each element of the transmission system, and the locational marginal price (LMP) for each generator and load area.

In this study, GE MAPS was set up to model the Eastern Interconnection of the United States and Canada. Other than Aquila Missouri, current RTO membership was assumed to continue in all cases. CRA used its current GE MAPS data base to perform the analysis, as well as its current projection of fuel prices and emission allowance prices. In order to assess the impact of future new entry, CRA used its proprietary National Energy & Environmental Model (NEEM) model to develop a capacity expansion forecast. CRA included currently planned or under construction resources throughout the Eastern Interconnect, including Iatan 2 in 2010. Potential CO_2 policies were not considered in this study. A full description of the GE MAPS inputs is contained in Appendix A.

3.1. Modeling Assumptions by Case

In distinguishing among the three scenarios, CRA worked with three categories of modeling assumptions: 1) wheeling charges, 2) effective flowgate capacity and 3) commitment region. Table 3 illustrates how these assumptions were applied in each case.

Table 3
Modeling Assumptions by Case

Case	Aquila MO Wheeling Charges to/from:			Effective Flowgate Capacity	Aquila MO Commitment Pool
	Midwest ISO	SPP RTO	Others		
Stand-alone	Yes	Yes	Yes	90%	Aquila MO
Member of Midwest ISO	No	Yes	Yes	100%	Midwest ISO
Member of SPP RTO	Yes	No	Yes	100%	SPP

Wheeling Charges: Wheeling charges are charges for moving energy from one control area to another in an electric system. In GE MAPS, wheeling rates are applied on a "per MWh" basis to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Wheeling rates are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch.

For this study, the wheeling rates for commitment were based on the day-ahead firm transmission rates (which are generally consistent with non-firm hourly on-peak rates) in the Aquila Missouri, Midwest ISO and SPP tariffs, while the rate for dispatch is based on non-firm hourly off-peak rates. This is to take into account that the day-ahead commitment process, in considering reliability, is more conservative in the type of capacity that is expected to be available.

The default assumption applied for wheeling rates on inter-ties in the modeled Eastern Interconnection region, other than between members of the same RTO, was $2 per MWh for both commitment and dispatch. Based on the Aquila Missouri tariff, the Aquila Missouri wheeling out rate in the Stand-alone case was also set at $2 per MWh for both dispatch and commitment.[15] Based on the Midwest ISO tariff, the wheeling rate from the Midwest ISO to SPP was set at $4 per MWh for dispatch and $6 for commitment.[16] Based on the SPP tariff, the wheeling rate from SPP to the Midwest ISO was set at $2 per MWh for both commitment and dispatch.[17] No wheeling rates were applied for flows within the SPP RTO or within the Midwest ISO. Given current policies, no wheeling rates were applied between PJM and the Midwest ISO.

Effective Flowgate Capacity: For the Stand-alone case, transfer limits on flowgates in the Aquila Missouri region were decreased by 10% to reflect the inefficiency of congestion management through the Transmission Loading Relief ("TLR") process. Flowgates are combinations of critical transmission elements that have the potential to become overloaded due to power flows on the transmission system. The 10% decrease was applied only to those Aquila Missouri flowgates directly impacted by transmission elements outside of the Aquila Missouri control area. The 10% figure was also applied in the SPP cost-benefit study performed by CRA in 2005 based on an examination of historical SPP tie-line flows during TLR events. Because of the uncertainty in exactly which units will be redispatched under a TLR call, and because of the time lag inherent in the process, it is difficult to achieve full system utilization when congestion is managed through the TLR process.

In contrast, RTO markets use market-based congestion management. Locational pricing is used to provide price signals that disclose congestion, signaling generation to redispatch, and enabling market participants to select alternative purchasing opportunities. This process ultimately relieves congestion more quickly and precisely than the TLR process. As a result, flowgates can be managed closer to their transfer limits under market-based congestion management.

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15 Wheeling rates were rounded to the nearest $/MWh integer, as is required in MAPS. The Aquila Networks rate is currently $2.07 per MWh on-peak and $0.98 per MWh off-peak for 345/161 kV service. SPP OATT, Rate Sheet for Point-To-Point Transmission Service for Aquila Networks – MPS/L&P. The Stand-alone wheeling rates for commitment and dispatch were both set to $2/MWh to be consistent with the default modeled region assumption for individual control areas.

16 Midwest ISO, Updated Discounted Pricing Information, oasis.midwestiso.org/doscuments/miso/pricing_new.html, as of January 30, 2007.

17 SPP through and out rates are based on the zone from which the power exits SPP's transmission system. The $2 rates are based on the Point-To-Point Transmission Service rates in the SPP OATT for KCP&L and SWPA inter-ties to the Midwest ISO market (i.e., to AmerenUE). For Westar Energy inter-ties to Aquila Missouri in the case when Aquila Missouri is in the Midwest ISO, the Westar Energy wheeling rate was set at $5 per MWh for commitment and $3 per MWh for dispatch based on the Westar Energy point-to-point rates in the SPP OATT.

Commitment Region: For the Stand-alone case, the day-ahead commitment of generating units for Aquila Missouri was performed for the Aquila Missouri control area, including jointly-owned units outside of the control area. As a Stand-alone entity, Aquila Missouri must commit its own resources in order to ensure control area reliability, as it would have limited ability to rely on external entities for commitment of their resources absent a contractual arrangement. For the RTO cases, the Aquila Missouri commitment was part of a pool-wide commitment encompassing the RTO, in which the unit commitment is optimized on a regional basis subject to transmission limitations. The ability to rely on the commitment of units across a broader region in the RTO markets allows for a more efficient unit commitment process.

4. BENEFITS AND COSTS

4.1. METHODOLOGY FOR MEASURING BENEFITS (COSTS)

This study assesses the benefits and costs associated with Aquila Missouri participating in the Midwest ISO or SPP RTO relative to Stand-alone status. Welfare for the regulated customers of Aquila Missouri, as measured in this study, is based on the charges to local area load for generation and transmission service, assuming that any benefits and costs to the regulated utility are passed through to its native load. If these charges to local area load decrease, regulated customer welfare increases. To quantify this change, CRA identified and analyzed potential sources of benefits and costs that impact the charges for generation and transmission service, such as generation (production) costs, energy purchases, and O&M expenditures.

The major categories of benefits and costs addressed in this study are trade benefits, RTO administrative costs, and Aquila Missouri internal implementation and operating costs. Trade benefits were computed using the GE MAPS results for each case. The methodology used to estimate the impact of each major category of benefits and costs is discussed below along with the corresponding results.

4.2. TRADE BENEFITS

The cases analyzed in this study (Aquila Stand-alone and Aquila in RTO) reflect varying degrees of impediments to trade between Aquila and surrounding regions. In particular, the wheeling rates and flowgate restrictions between Aquila and the Midwest ISO and SPP RTO in the Stand-alone case result in impediments to trade that are reduced when Aquila is a member of an RTO. Reductions in the impediments to trading should generally result in production cost savings. Generation production costs are actual out-of-pocket costs for operating generating units that vary with generating unit output; they comprise fuel costs, variable O&M costs, and the cost of emission allowances. By decreasing impediments to trading, additional generation from utility areas with lower cost generation replaces higher cost generation in other utility areas. These production cost savings yield the "trade benefits" referred to in this study.

Increases or decreases in production cost in any particular utility area, by themselves, do not provide an indication of welfare benefits for that area, because that area may simply be importing or exporting more power than it did under base conditions. For example, a utility that increases its exports would have higher production costs (because it generates more power that is exported) and would appear to be worse off if the benefits from the additional exports were not considered. Similarly, a utility that imports more would have lower production costs, but higher purchased power costs. In either circumstance – an increase in imports or exports – an accounting of the trade benefits between buyers and sellers must be made in order to assess the actual impact on utility area welfare. Increased trading activity provides benefits to both buying parties (purchases at a lower cost than owned-generation cost) and selling parties (sales at a higher price than owned-generation cost). In practice, the benefits of increased trade are divided between buying and selling parties. For example, the "split-savings" rules that govern traditional economy energy transactions between utilities under cost-of-service regulation result in a 50-50 split of trading benefits.[18]

4.2.1. Measurement of Aquila Missouri Trade Benefits

Traditional cost-of-service regulation differs from a fully deregulated retail market, in which individual customers and/or load-serving entities buy all their power from unregulated generation providers at prevailing market prices. In such a deregulated market, benefits to load can be ascertained mostly in terms of the impact that changes to prevailing market prices have on power purchase costs. For the Aquila Missouri region, in which cost-of-service rate regulation is in effect, the energy portion of utility rates reflects the production cost for the utility's owned generating units, plus the cost of "off-system" purchased energy, net of revenues from "off-system" energy sales. In turn, Aquila Missouri's utility customers under cost-of-service regulation pay for the fixed costs of owned-generating units through base rates. Deriving trade benefits for Aquila Missouri thus requires an analysis of both the production cost of operating the Aquila Missouri owned generating plants and the associated Aquila Missouri trading activity (purchases and sales).

The production cost of the Aquila Missouri-owned generating units is derived directly from the MAPS outputs for each case. This includes Aquila Missouri's share of jointly owned units, and its long-term contractual ownership of generating capacity, as shown in Appendix B. Other than its share of Iatan 2, no additional Aquila Missouri owned units were assumed in this study.

18 Consider a simple two-company example. Assume there is a \$16 marginal cost to generate in Company A's control area and a \$20 marginal cost to generate in Company B's control area and there is no trade. Now assume through a reduction in trade impediments that 1 MW can be traded from A to B over the inter-tie between A and B. Company A will generate 1 MW more at a production cost of \$16, while Company B will generate 1 MW less at a production cost savings of \$20. Thus, the total saving in production cost is \$4 (i.e., \$20 – \$16). If the trade price is set, for example, at a 50/50 split savings price, Company A will receive \$18, for a trade benefit of \$2 (\$18 – \$16), and Company B will pay \$18, for a trade benefit of \$2 (\$20 – \$18). The total trade benefit of \$4 (\$2 + \$2) will match the total production cost saving of \$4.

For purposes of deriving the impact of trading with adjoining regions, the net hourly MAPS tie-line flows into and out of Aquila Missouri were used as a proxy for purchase and sale transactions by Aquila Missouri. In each hour, the net interchange was derived using Aquila Missouri tie-line flows to assess whether Aquila Missouri was a net importer (purchaser) or exporter (seller) of power. If a net purchaser in the hour, the net purchase amount was multiplied by the weighted average split-savings price for tie-lines with flows into the Aquila Missouri control area. Similarly, if Aquila Missouri was a net exporter (seller) in the hour, the net sale amount was multiplied by the average split-savings price for tie-lines with outgoing flows. The split-savings prices reflects a 50/50 sharing of the price difference (and trade benefits), adjusted for the applicable wheeling charge, across the MAPS tie lines between Aquila Missouri and adjacent control areas. This also means that to the extent that Aquila Missouri has trade benefits, adjacent control areas are sharing in those trade benefits.

Prior to this hourly net interchange calculation, an adjustment is made to the Aquila Missouri tie-line flows for the power produced by the Aquila Missouri jointly-owned and contracted units located outside of the Aquila Missouri control area. The generation and production costs for Aquila Missouri's share of units located outside of the Aquila Missouri control area are included in Aquila Missouri's total generation and production costs. For purposes of this study, it is assumed that Aquila Missouri purchases the output of the 580 MW Aries combined-cycle unit located in the Aquila Missouri control area at prevailing locational market prices. To the extent that such an arrangement would require an additional capacity-type payment to the merchant unit, it is assumed this payment would be the same in each of the cases. As an intra-control-area unit purchase, these Aries purchases are included in the generation category in the tables in this study along with other Aquila unit purchases.

Wheeling charges on net hourly imports into Aquila Missouri are paid by the native load in Aquila Missouri, and are included in the Aquila Missouri purchase costs in this study. Wheeling charges on net hourly exports from the Aquila Missouri control area are paid by the load in the importing control area to Aquila Missouri (thereby reducing the net Aquila Missouri transmission revenue requirement) and are included in the Aquila Missouri sales revenue in this study.

4.2.2. Trade Benefit Results

Table 4 shows the change in Aquila Missouri generation, purchases and sales for the years 2008, 2012 and 2017 in the RTO cases in comparison to the Stand-alone case. As shown, there is a reduction in generation in the RTO cases. However, the reduction is significantly greater in the SPP RTO case. Aquila Missouri generation as used here includes generation in the Aquila Missouri control area including the merchant Aries unit, plus Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area.

Table 4
Increase in Aquila Missouri Generation, Purchases and Sales in RTO in comparison to Stand-alone Status (GWh)

	Member of Midwest ISO			Member of SPP RTO		
	2008	2012	2017	2008	2012	2017
Generation	(94)	(258)	(381)	(1324)	(2173)	(2562)
Purchases	348	556	497	959	1788	2330
Sales	254	299	116	(364)	(386)	(232)
Net (G+P-S)	0	0	0	0	0	0

Table 5 lists the trade benefits (i.e., the change in the net cost to serve load) to Aquila Missouri in the RTO cases in comparison to the Stand-alone case. The change in the generation costs, purchase costs and sales revenue correspond to the changes in the GWh of generation, purchases and sales shown in Table 4. As shown, the trade benefits are positive for both RTO cases, but more positive for the SPP RTO case.

Table 5
2008-2017 Trade Benefits to Aquila Missouri of RTO Membership in comparison to Stand-alone Status
(in millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Decrease in Production Costs	45.9	673.4
Decrease in Purchase Costs	(103.5)	(465.5)
Increase in Sales Revenues	87.6	(112.1)
Total Trade Benefits	**29.9**	**95.7**

The production costs listed in Table 5 are comprised of the fuel, variable O&M, start-up and emissions costs for Aquila Missouri generating units, including Aquila Missouri's share of jointly-owned units and unit purchases located outside of the Aquila Missouri control area. For purposes of Table 5, the production costs also include the purchase of the output of the merchant Aries unit at prevailing market prices.

The greater trade benefits resulting from membership in the SPP RTO appear to be primarily the result of Aquila Missouri's location and the nature of its transmission inter-ties with adjoining control areas. Aquila Missouri is located on the western side of Missouri and heavily interconnected with KCP&L in particular. The total MVA capacity rating on the transmission lines that interconnect Aquila Missouri with SPP RTO members (KCP&L and Westar Energy) is more than five times as large as the ratings on the lines that interconnect

Aquila Missouri with Midwest ISO market members (AmerenUE).[19] Moreover, regardless of Aquila Missouri status (Stand-alone, in the Midwest ISO, or in the SPP RTO) the magnitude of the Aquila Missouri power flow to and from the SPP RTO over the tie-lines in the GE MAPS model runs is significantly higher than that over the tie-lines to and from Midwest ISO market members. These physical inter-ties between Aquila Missouri and the SPP RTO exist regardless of whether Aquila Missouri is in the SPP RTO or the Midwest ISO. However, placing cost impediments (e.g., wheeling charges for transactions between Aquila and the SPP RTO) on these inter-ties, as would be the case if Aquila Missouri were in the Midwest ISO, provides a substantial impediment to Aquila Missouri trade.

As a result, the GE MAPS runs indicate that Aquila Missouri is able to displace control area generation, particularly gas-fired generation, with less expensive market purchases to a greater extent in the SPP RTO case. As shown in Table 6, Aquila Missouri generation, which is roughly equal to Aquila Missouri load in the Stand-alone case, is reduced in the RTO cases, but is reduced significantly more in the SPP RTO case. This reduction in generation in the SPP RTO case indicates that additional economic purchases are displacing Aquila Missouri generation in the SPP RTO case through the unit commitment process and through the elimination of wheeling charges with SPP RTO members. In particular, the gas-fired Aries combined-cycle unit is committed and generates significantly more often in the Stand-alone and Midwest ISO cases than in the SPP RTO case.

Table 6

Decrease in Aquila Missouri Generation in RTO in comparison to Stand-alone Status

	Decrease in Generation (GWh)			Decrease as Share of Net Aquila Load		
	2008	2012	2017	2008	2012	2017
In Midwest ISO	94	258	381	1%	3%	3%
In SPP RTO	1,324	2,173	2,562	15%	22%	23%

As noted above, the Aries generation is assumed to be purchased by Aquila Missouri at prevailing market prices in all cases. The 580 MW Aries unit owned by Calpine was auctioned to Kelson Energy for $235 million in December 2006 over Aquila Missouri's competing bid of $230 million. To the extent that Aries output becomes contracted to entities outside of the Aquila Missouri control area, Aquila Missouri likely would need to make additional purchases and/or commit and generate more energy from the gas-fired South Harper peaking unit or other units. The additional energy needed would be greater in the Stand-alone and Midwest ISO cases and likely would further increase the relative benefit of the SPP RTO case.

19 NERC Multi-regional Modeling Working Group ("MMWG") 2005 series 2010 summer peak loadflow.

4.3. ADMINISTRATIVE AND OPERATING COSTS

A number of costs must be analyzed in addition to those directly addressed in GE MAPS. These include Aquila implementation and operating costs and RTO administrative charges. The specific categories of costs addressed in this study are discussed in detail below.

4.3.1. Stand-alone Costs to Provide Current SPP and Midwest ISO Functions

In addition to its long-running role as Aquila Missouri's NERC reliability council, SPP performs a number of other reliability/transmission provider functions for Aquila Missouri, namely: 1) tariff administration, 2) OASIS administration, 3) available transmission capacity (ATC) and total transmission capacity (TTC) calculations, 4) scheduling agent, and 5) regional transmission planning. The Midwest ISO performs a sixth needed function, reliability coordination, for Aquila Missouri. As discussed previously, moving to Stand-alone status would require Aquila Missouri to procure these six services from an alternative supplier or provide them internally. In turn, however, Aquila Missouri would avoid payment to SPP and the Midwest ISO for provision of these functions.

Appendix C provides an overview of the analysis performed by Aquila Missouri personnel to estimate the costs to provide or procure these six reliability/transmission provider functions on a Stand-alone basis. The costs were then converted by CRA into annual revenue requirements. The analysis indicates that Aquila Missouri would incur additional costs of $16.0 million over the 10-year study period to provide these six functions. Since this is an additional cost for the Stand-alone case, the $16.0 million is counted as a savings (or benefit) to each of the two RTO cases in comparison to Stand-alone status.

4.3.2. RTO Administrative Charges

Both the Midwest ISO and the SPP RTO incur significant capital and operating costs to operate their markets. These costs are recovered through administrative charges that would be payable by Aquila if it were to be an RTO member. The Midwest ISO assesses these charges under Schedules 10, 16 and 17 under its tariff. The Midwest ISO projects the charges under these schedules over the 2007 to 2011 period to average about 36 cents per MWh of member load.[20] Of this total, about 13 cents per MWh is for Schedule 10 (ISO Cost Recovery Adder), 2.5 cents is for Schedule 16 (FTR Administrative Service), and 20.5 cents is for Schedule 17 (Energy Markets Support). SPP RTO charges are expected to be about 20% lower on a cents per MWh basis over the next few years, including operation of the real-time imbalance market, than those of the Midwest ISO. The SPP RTO costs do not yet

20 Midwest ISO, Recommended Capital and Operating Budget, Section IV, Projected Average Administrative Cost per MWH, December 14, 2006.

include any administrative charges for a day-ahead market, financial transmission rights, and an ancillary services market.

At the request of CRA, SPP provided a preliminary forecast of charges to be incurred upon development and operation by SPP of a day-ahead market, FTRs, and an ancillary services market. On a preliminary basis, SPP projected costs per MWh of member load roughly equivalent to those of the Midwest ISO upon full institution of these additional markets.

Like the Midwest ISO, the PJM RTO also has day-ahead markets and FTR markets in operation. In 2006, the PJM RTO converted to a system of stated rates that result in projected RTO administrative charges roughly similar to those projected by the Midwest ISO.[21] For purposes of this study, given that the RTO markets are assumed to have similar markets and operations over the long-term study period, the projected Midwest ISO administrative charges were applied in both the Midwest ISO and SPP RTO cases.[22]

We note that the following of best practices and pressure by RTO members to minimize costs will tend to minimize differences in RTO costs. Even so, potential longer-term cost differences between the two RTOs could result from the following:

- At the present time, the Midwest ISO serves a market load roughly three times larger than that of the SPP RTO. Given economies of scale in RTO operations, this likely favors the Midwest ISO having lower administrative charges per unit of energy for load. Of course, new RTO members and any exiting members could alter this relationship.

- SPP has not yet developed market components beyond a real-time market. This provides additional cost uncertainty for SPP. However, the later development could allow SPP to develop these markets using knowledge and systems gleaned from operations at RTOs with these markets in place. This potentially favors lower development costs for SPP, all else equal.

- The Midwest ISO has a number of deferred charges that are being assessed over time to its members. The market-related deferred charges were $80.8 million as of the end of 2005, and are projected to be recovered by 2011.[23] These deferred charge recoveries are offset by amortization to members of about $45 million over

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21 Settlement Agreement and Offer of Settlement, PJM Interconnection, LLC, FERC Docket No. EL05-1181, April 18, 2006. The PJM stated rates will average 30 to 32 cents per MWh from 2006 to 2011, supplemented by an additional rider for the construction and operation of a second control center.

22 The Midwest ISO projected unit charges through 2011. After 2011, the annual RTO administrative charges for Aquila Missouri were assumed to escalate at inflation.

23 Midwest ISO, Annual Report 2005, pages 29-30.

the 2007 to 2011 period resulting from the exit charges that have been paid to the Midwest ISO.[24] SPP does not have similar deferred charges at this time. All else equal, this likely favors SPP having somewhat lower unit administrative charges until these Midwest ISO deferrals are completed.

Using the Midwest ISO projection of administrative costs, the Aquila RTO cases are projected to incur $23.5 million (2007 present value) in RTO administrative charges over the 10-year study period. See Appendix C for further detail. This is an additional cost to the two RTO cases in comparison to the Stand-alone case.

4.3.3. FERC Charges

All load-serving investor-owned utilities must pay annual FERC charges in order for FERC to recover its administrative costs. Historically, these FERC charges have been assessed to individual investor-owned utilities based only on the quantity of the utility's wholesale transactions (i.e., those related to interstate commerce). However, the annual FERC charges for RTO member load-serving utilities are assessed directly to the RTO, and then in turn assessed by the RTO to member companies. Under FERC regulations, the annual FERC charge is assessed to all RTO energy for load. FERC charges for RTO members are therefore higher for non-RTO members.

As more of the country's utilities join an RTO, the FERC per-unit charges for energy transmitted in interstate commerce are likely to decrease. Nevertheless, as long as only wholesale transactions are assessed the FERC charge under a non-RTO (Stand-alone) basis, there will be higher FERC charges to RTO members than non-RTO members, all else being equal.

For purposes of this study, the difference in the FERC charges between the Stand-alone and RTO cases was estimated by comparing the FERC charges estimated by the Midwest ISO (on a dollars per load served basis) in 2007 to the average inflation-adjusted FERC charges paid by Aquila Missouri in the 2004–2005 period. This annual difference was then escalated at inflation and discounted over the 10-year study period. Using this approach, the increase in FERC fees for Aquila Missouri under the two RTO cases is $1.3 million (2007 present value) over the study period in comparison to the Stand-alone case. See Appendix C for further detail.

4.3.4. Aquila Internal RTO Market Participation Costs

RTO market participants will incur expenditures to participate in an RTO market over and above the RTO administrative charges. However, in order to interface and trade with surrounding RTOs, Aquila Missouri has already invested in the computer systems and staff

24 Midwest ISO, Recommended 2007-2009 Budget, page 5, December 14, 2006.

training needed to interact with the RTOs. This includes investment in an OATT system. As such, no further additional internal costs have been included for Aquila in the RTO cases.

4.4. Overall Cost-Benefit Results

Table 7 provides the benefits (shown as positive numbers) and costs (shown as negative numbers) discussed above for Aquila membership in the Midwest ISO or SPP RTO in comparison to Stand-alone status. As shown, the quantitative findings indicate a net benefit to Aquila Missouri in joining an RTO relative to Stand-alone operations. The results are the mid-2007 present value of the net benefits over the 2008 to 2017 period.

Table 7
2008-2017 Benefits (Costs) to Aquila Missouri of RTO Membership in comparison to Stand-alone Status
(in millions of 2007 present value dollars; positive numbers are benefits)

	Member of Midwest ISO	Member of SPP RTO
Trade Benefits: Decrease in Cost to Serve Aquila Missouri Load	29.9	95.7
Savings from RTO Providing Reliability/Transmission Functions	16.0	16.0
RTO Administrative Charges	(23.5)	(23.5)
FERC Charges	(1.3)	(1.3)
Total Benefits (Costs)	**21.1**	**86.9**

As shown in Table 7, the trade benefits of joining an RTO, i.e., the savings in the net cost to serve Aquila Missouri load, are positive and range from $30 to $96 million over the 10-year study period. The savings that Aquila incurs by having the RTO perform transmission and reliability functions rather than performing or procuring these functions on a Stand-alone basis are $16.0 million over the 10-year study period. The administrative charges that Aquila would incur for being a member of the RTO market are $23.5 million over the 10-year study period. This is an additional cost and thus is shown as a negative benefit in Table 7. And finally, the charges paid to FERC that Aquila would be assessed as a member of an RTO would be $1.3 million higher than if Aquila were Stand-alone over the study period.

The overall net benefit to Aquila of being in an RTO is projected to be $21 to $87 million over the 10-year study period. In addition, the annual net benefits are projected to be positive for each year of the study period (see Appendix C).

A key risk factor in joining an RTO is the amount of RTO administrative charges that could be incurred. However, even if the $23.5 million of RTO administrative charges shown in Table 7 increased by 50% from those projected in this study, there would still be considerable benefits for Aquila Missouri joining an RTO.

With respect to whether it would be more economic to join the Midwest ISO or the SPP RTO, the quantitative results indicate a greater benefit for Aquila Missouri being a member of the SPP RTO. As noted above, this benefit is premised on the SPP RTO having in place additional market development that it does not yet have in place, and operating these markets at costs comparable to the Midwest ISO.

Given the smaller size, in terms of market member load, of the SPP RTO, economies of scale could result in higher administrative costs per MWh for the SPP RTO with further market development. However, given the differences in Aquila Missouri net benefits found in the MAPS modeling, even a 50% greater administrative charges per MWh for the SPP RTO would not alter the quantitative advantage found in this study for Aquila Missouri being a member of the SPP RTO. Nonetheless, the SPP RTO does not yet have the same level of market development as the Midwest ISO and as modeled in this study. As such, uncertainty exists as to the timing of any future SPP RTO market developments and the costs that would be incurred in putting in place those developments.

4.4.1. High Gas Price Sensitivity

Given historic volatility in natural gas prices, CRA also conducted a one-year sensitivity analysis of the impact that much higher natural gas prices would have on net benefits. The natural gas price forecast used in the GE MAPS modeling (see Figure 1 in Appendix A) declines substantially from 2008 through 2012 in accordance with current natural gas market futures. The average natural gas price projected for the Henry Hub of $7.60 per MMBtu (2005$) in 2008 declines to $5.60 by 2012.

Given this projected decline already included in the base modeling, a relatively large increase in gas prices was tested in the 2012 gas sensitivity model runs to address the potential for 2012 gas prices to be significantly higher than 2008 levels. Specifically, the gas prices applied for 2012 in this sensitivity case were increased from $5.60 to $9.00 per MMBtu (2005$), or to a level about 18% higher than base 2008 gas prices. As shown in Table 8, with these high gas prices, the 2012 trade benefits for the Midwest ISO and SPP RTO cases increase significantly.

Table 8
Impact of Higher Gas prices on 2012 Aquila Missouri Trade Benefits (Costs) from RTO Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

2012 Trade Benefits	Member of Midwest ISO	Member of SPP RTO
With Base 2012 Gas Prices	3.7	16.1
With High 2012 Gas Prices	10.6	28.0
Increased Benefits (Costs)	**6.1**	**11.8**

Relative to the base gas price case, the high gas price case for 2012 shows a greater percentage increase in trade benefits for membership in the Midwest ISO, but a higher absolute increase in benefits for membership in the SPP RTO. These results support the finding that with a significantly higher level of gas prices, the decision for Aquila to join an RTO would become even more favorable.

5. QUALITATIVE CONSIDERATIONS

Aside from the specific benefits quantified above, participation in an RTO is likely to provide additional benefits, along with some cost risks, as discussed below.

Regional Transmission Management. Participation in an RTO is likely to assist Aquila Missouri in the regional management of parallel path flows, management of reserve sharing, and the regional coordination/planning of transmission investment. These benefits result from addressing issues at a regional level rather than that of a local control area unable to examine or to be fully cognizant of the actions of surrounding areas that can impact their local control area. The RTO real-time markets should allow for economic redispatch to alleviate the need for TLR events. TLR is a real-time operating procedure that allows reliability coordinators to mitigate violations of reliability limits through curtailments and redispatch actions. The need for a TLR often arises when transaction schedules are not fully-coordinated among control areas in advance of real-time operations. Finally, single region-wide OASIS administration should also provide additional efficiencies relative to Aquila Missouri in Stand-alone status.

Price Transparency. The inclusion of a transmission system in a transparent regional market with locational price signals will provide additional incentives to improve generation availability when economic to do so, and will help in the planning process in placing transmission improvements and new generation capacity in optimal locations. The transparency of the pricing provides an additional tool for regulators to monitor the efficiency of utility purchases and sales

Costs. Aside from the specific issues identified above, one of the main concerns regarding RTO membership has been the magnitude of the administrative charges, and the perception that individual members may not have enough ability to directly control the underlying RTO expenditures. In response, the Midwest ISO has reduced its budgeted expenditures[25] and is projecting relatively stable costs in terms of costs per MWh over the next five years. Moreover, the PJM RTO has moved to a form of stated rates, rather than a direct formula passthrough of all costs. These stated rate are expected be in place through 2011, indicating greater confidence on the part of RTO management in the predictability of costs as RTO markets mature. In addition, FERC has issued reporting rules to allow for greater

25 Midwest ISO Trims Operating Costs, Midwest ISO News Release, June 19, 2006.

transparency in evaluating RTO costs.[26] While these trends appear favorable to the stabilization of RTO costs, there continues to be ongoing uncertainty about future RTO market developments and refinements that result in ongoing cost risk to member utilities.

Market Monitoring. Market monitoring and mitigation is an essential function for RTOs and is required by FERC Order 2000. Both the Midwest ISO and SPP have established independent market monitors. In CRA's view, Aquila Missouri's entry into an RTO is unlikely to increase significantly the likelihood of actual exercises of market power in the Aquila Missouri region. This is because most power delivered within Missouri will be subject to the continuation of cost-based retail rates. In addition, it is our understanding that much of the wholesale market is covered by long-term contracts for which a short-term increase in the spot price for power would be immaterial. In these circumstances, generation owners would have little, if any, incentive to withhold generation from the RTO markets for the purpose of increase in the market-clearing price in that market. This is because the output of the generating unit is committed to load under regulatory and contractual arrangements under which it is not possible to earn additional revenue merely because of an increase in the spot market price. Without the incentive to exercise market power, the issue is likely to be a minor consideration in the decision to join an RTO. Nonetheless, it is important that the RTO market monitors review the performance of their markets to FERC as needed. The market monitoring function is an important deterrent to the exercise of whatever residual market power exists in the market.

6. CONCLUSION

The results of the quantitative analysis show a net benefit for Aquila Missouri joining either the Midwest ISO or the SPP RTO. Qualitative considerations further buttress the likelihood of net benefits resulting from RTO entry by Aquila Missouri. The quantitative results indicate a greater benefit for Aquila Missouri to join the SPP RTO than the Midwest ISO. The relative benefits are high enough to offset potentially greater administrative costs at SPP given its smaller size. These quantitative results are premised on additional market developments in the SPP RTO that have not yet been formally proposed or budgeted. Thus, there is uncertainty regarding the timing and cost of these additional SPP market developments.

26 RTO Costs to be Reflected in Accounting Rules, FERC News Release, Docket No. RM04-12-000,, December 15, 2005

7. APPENDIX A: MAPS INPUTS

This appendix summarizes the key inputs to the GE MAPS locational price forecasting model. As formulated for this study, the model's geographic footprint encompasses the U.S. portion of the Eastern Interconnect and the Canadian province of Ontario with the major focus on the SPP, Midwest ISO and surrounding regions. The GE MAPS simulations focus on the ten-year period from 2008 to 2017. The years directly simulated are 2008, 2012 and 2017. Results for intervening years are interpolated.

Primary data sources for the model include the NERC MMWG, the General Electric generation and transmission databases for the Eastern Interconnect, various publications by NERC regions and Independent System Operators, FERC submissions by generation and transmission owners, commercial databases from Platt's and Energy Velocity and CRA in-house analysis of plant operations and market data.

7.1. TRANSMISSION

The CRA model is based on load flow cases provided by the NERC Multiregional Modeling Working Group (MMWG). This analysis uses the modified MMWG 2005 series load flow cases for the summer of 2007 and 2010. The MMWG load flow case encompasses the entire Eastern Interconnect system, including lines, transformers, phase shifters, and DC ties. CRA adds to these load flows the Cross-Sound and Neptune high voltage DC cables. Load flow models were further analyzed against regional transmission planning documents and a number of changes were made to the load flow to reflect future transmission projects (those under construction or having a high probability to be implemented, but not included in the original MMWG models).

Monitored constraints originate from the following sources:

- The NERC flowgate book (November 2005 version).
- The list of flowgates published by the Midwest ISO on its website.
- A list of flowgates provided by the Southwest Power Pool.
- FERC Form 715 filings, seasonal transmission assessment reports, and studies published by NERC regions and Independent System Operators.
- Regional Transmission Expansion Plan (RTEP) reports published by various ISOs.
- The 2004 Intermediate Area Transmission Review published by the New York ISO.
- Contingency analyses performed by General Electric and by CRA.
- Historically binding constraints monitored by CRA.

For constraints monitored for their thermal limit violations, their limits are updated with respect to each load flow to reflect transmission upgrades. For constraints enforced for stability purposes, we use the limits obtained from the sources above.

Reducing the number of constraints monitored in the study reduces the time required for GE MAPS to solve the optimal commitment and dispatch. Therefore, CRA filters out non-significant constraints far away from the study areas to speed up the process. In this study, all non-duplicate constraints from the above sources within MISO, SPP and Entergy are included. For other study areas, a constraint is included only if it has been binding in our previous studies or it monitors facilities at 500KV or above.

7.2. LOAD INPUTS

For each load serving entity, GE MAPS requires an hourly load shape and an annual forecast of peak load and total energy. CRA uses the latest EIA-411 load forecast data available (2006) for each company within the study region. Ontario data is drawn from the 10-Year Outlook: Ontario Demand Report published by the Independent Electricity Market Operator of Ontario. If study years are to be modeled after the last year for which forecast data is available, CRA uses linear extrapolation to estimate the peak load and annual energy, by company, for the remaining years.

Load shapes are drawn from hourly actual demand for 2002, as published in FERC Form 714 submissions and on the websites of various Independent System Operators (ISOs) and NERC reliability regions. These hourly load shapes, combined with forecasts for peak load and annual energy for each company, are used by GE MAPS to develop a complete load shape by company for each forecast year.

7.3. THERMAL UNIT CHARACTERISTICS

Description. MAPS models the operational characteristics of generation units in detail to predict hourly dispatch and prices. The following characteristics are modeled:

- Unit type (*e.g.*, steam cycle, combined-cycle, simple cycle, cogeneration)
- Heat rate values and curve (based on unit technology)
- Summer and winter capacity
- Variable operation and maintenance costs
- Fixed operation and maintenance costs
- Forced and planned outage rates
- Minimum up and down times
- Quick-start and spinning reserves capabilities
- Startup costs
- Emission rates

CRA's generation database reflects unit-specific data for each generating unit based on a variety of sources. If unit-specific operational data were not available for a particular unit, representative values based on unit type, fuel, and size were used. Table 9 and Table 10 documents these generic assumptions.[27] As is the case throughout this MAPS analysis, all costs are in real 2005 dollars.

27 Note that certain data types are specified on a plant-specific basis in CRA's database and therefore do not require corresponding generic data. These include full load heat rates and emissions data.

Table 9: Characteristics for Generic Thermal Units

Unit Type & Size	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Minimum Downtime (Hrs)	Minimum Uptime (Hrs)	Heat Rate Shape
Combined Cycle	$ 2.50	$ 21.00	8	6	2 Blocks, each 50% at FLHR
Combustion Turbine <100 MW	$ 7.00	$ 15.00	1	1	One block
Combustion Turbine >100 MW	$ 7.00	$ 15.00	1	1	One block
Steam Turbine [coal] >200 MW	$ 1.00	$ 35.00	12	24	4 blocks, 50% @ 106%FLHR, 15% @ 90%, 30% @ 95%, 5% @ 100%
Steam Turbine [coal] <100 MW	$ 3.00	$ 45.00	6	8	
Steam Turbine [coal] <200 MW	$ 3.00	$ 35.00	8	8	
Steam Turbine [gas] >200 MW	$ 3.00	$ 30.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [gas] <100 MW	$ 5.00	$ 34.00	6	10	
Steam Turbine [gas] <200 MW	$ 4.00	$ 30.00	6	10	
Steam Turbine [oil] >200 MW	$ 3.00	$ 30.00	8	16	4 blocks, 25% @ 118%FLHR, 30% @ 90%, 35% @ 95%, 5% @ 103%
Steam Turbine [oil] <100 MW	$ 5.00	$ 34.00	6	10	
Steam Turbine [oil] <200 MW	$ 4.00	$ 30.00	6	10	

Table 10: Characteristics for Generic Thermal Units

Unit Type & Size	Quick Start (% of Capacity)	Spinning Reserve (% of Capacity)	Forced Outage Rate (%)	Planned Outage Rate (%)	Typical Outage Length (Days)
Combined Cycle	-	30%	1.81%	7.40%	3
Combustion Turbine <100 MW	100%	90%	2.81%	5.28%	1
Combustion Turbine >100 MW	100%	90%	2.60%	6.94%	1
Steam Turbine [coal] >200 MW	-	10%	3.07%	9.10%	7
Steam Turbine [coal] <100 MW	-	10%	3.78%	8.32%	3
Steam Turbine [coal] <200 MW	-	10%	4.57%	9.43%	3
Steam Turbine [gas] >200 MW	-	10%	3.50%	14.11%	7
Steam Turbine [gas] <100 MW	-	10%	2.62%	6.81%	2
Steam Turbine [gas] <200 MW	-	10%	3.23%	11.11%	2
Steam Turbine [oil] >200 MW	-	10%	2.79%	13.51%	7
Steam Turbine [oil] <100 MW	-	10%	1.46%	8.33%	2
Steam Turbine [oil] <200 MW	-	10%	3.01%	12.16%	2

Data Sources. The primary data source for generation units and characteristics is the NERC Electricity, Supply and Demand (ES&D) 2003 database, which contains unit type, primary and secondary fuel type, and capacity data for existing units. Heat rate data were drawn from prior ES&D databases where available. For newer plants, heat rates were based on industry averages for the technology of each unit. The NERC Generation Availability Data System (GADS) database published in January 2005 (data through 2003) was the source for forced and planned outage rates, based on plant type, size, and age.

Fixed and variable operation and maintenance costs are estimates based on plant type, size, and age. These estimates are supplemented by FERC Form 1 submissions where available. The fixed operations and maintenance cost (FOM) values include an estimate of $1.50/kW-yr for insurance and 10% of base FOM (before insurance) for capital improvements.

Plants that are known to be cogeneration facilities are either modeled with a low heat rate (6,000 Btu/kWh), or set as must-run units in the dispatch, to reflect the fact that steam demand requires operation of the plant even when uneconomical in the electricity market.

7.4. Nuclear Units

Description. CRA assumes that all nuclear plants run when available and that they have minimum up and down times of one week. Forced outage rates for each nuclear unit are drawn from the Energy Central database of unit outages. These plants do not contribute to quick-start or spinning reserves. Refueling and maintenance outages for each nuclear plant are also simulated. Outages posted on the NRC website or announced in the trade press for the near future are included. For later years, refueling outages for each plant are projected based on its refueling cycle, typical outage length, and last known outage dates. Since these facilities are treated as must-run units, CRA does not specifically model their cost structure.

Data Sources. Nuclear unit data were obtained from NRC publications, trade press announcements, and the Energy Central database.

7.5. Hydro Units

Description. MAPS has special provisions for modeling hydro units. For conventional or pondage units, CRA specifies a pattern of water flow, i.e., a minimum and maximum generating capability and the total energy for each plant. CRA assumes that hydro plants can provide spinning reserves of up to 50% of plant capacity. CRA assumes that the maximum capacity for each hydro unit is flat throughout the year, that the minimum capacity is zero (i.e., that there are no stream-flow or other constraints that force a plant to generate). Plant monthly energy data is drawn from an average of Form EIA-860 submissions for 1992-1998.

Data Sources. The list of hydro units and their maximum generating capacities is taken from the NERC ES&D database.

7.6. Wind Resources

Description. Individual wind resources were modeled either as zero-cost dispatchable energy resources with high (70%) outage rates or as hourly modifiers based on historical production data. Solar generators are run at 24% annual capacity factor, and restricted to daytime hours.

7.7. Capacity Additions and Retirements

The initial set for new entry is based on existing projects in development and on projects with signed interconnection agreements as of December 2006, including Iatan 2 in 2010. For study years 2012 and 2017, CRA added capacity based on economic and/or reliability criteria using CRA's proprietary CRA's North American Electricity & Environment Model (NEEM). Capacity additions are made such that each capacity region complies with its specified reserve margin. New capacity can also be added if the economics of adding new capacity result in lower present value on-system electric sector costs over the time horizon of the model (i.e., reduced operating costs more than offset capital costs). The choice of new capacity will depend on a number of key inputs, but foremost on capital costs of the new capacity and fuel costs. Capital costs used in NEEM are generally based on information included in EIA's Annual Energy Outlook 2006, with adjustments for such factors as the recent run-up in steel prices, additional costs of adding transmission and natural gas pipeline. The natural gas and oil prices described herein that are applied in the MAPS model are also applied in the NEEM model.

The least cost capacity decisions from NEEM are then added to the MAPS database for balancing purposes. Other information from NEEM that is used in MAPS includes: coal choices, delivered coal prices, emission rates for SO_2, NO_X and Hg, allowance prices for SO_2, NO_X and Hg, and unit retirements. NEEM is a process-based model of national US electricity markets (with limited representation of Canada as well). Electricity markets are divided into 27 individual demand regions (based on NERC sub-regions) and interconnected by limited transmission capabilities (also based on NERC data). Units are dispatched to load duration curves within each region so that all loads are met at least cost. Every existing generating unit in the US is represented in the model, with its current emissions control equipment. NEEM was designed specifically to be able to simultaneously model least-cost compliance with all regional and national, seasonal and annual emissions caps for SO_2, NO_X and Hg (and CO_2 if relevant). NEEM has been widely used within the electric sector to analyze the costs, impacts, and allowance prices of multi-pollutant proposals.

The capacity expansion did not vary by case in this study. According to the NEEM results, no capacity was retired in the SPP region during the study period. Taking into account already planned generating additions, no additional capacity was added in the NEEM modeling in this region. The NEEM modeling is designed to provide a consistent basis for estimating capacity expansion throughout the Eastern Interconnect. By necessity, the capacity expansion in the NEEM analyses is a projection based upon generalized input assumptions and will vary from actual future experience, including the size, type and location of specific new units.

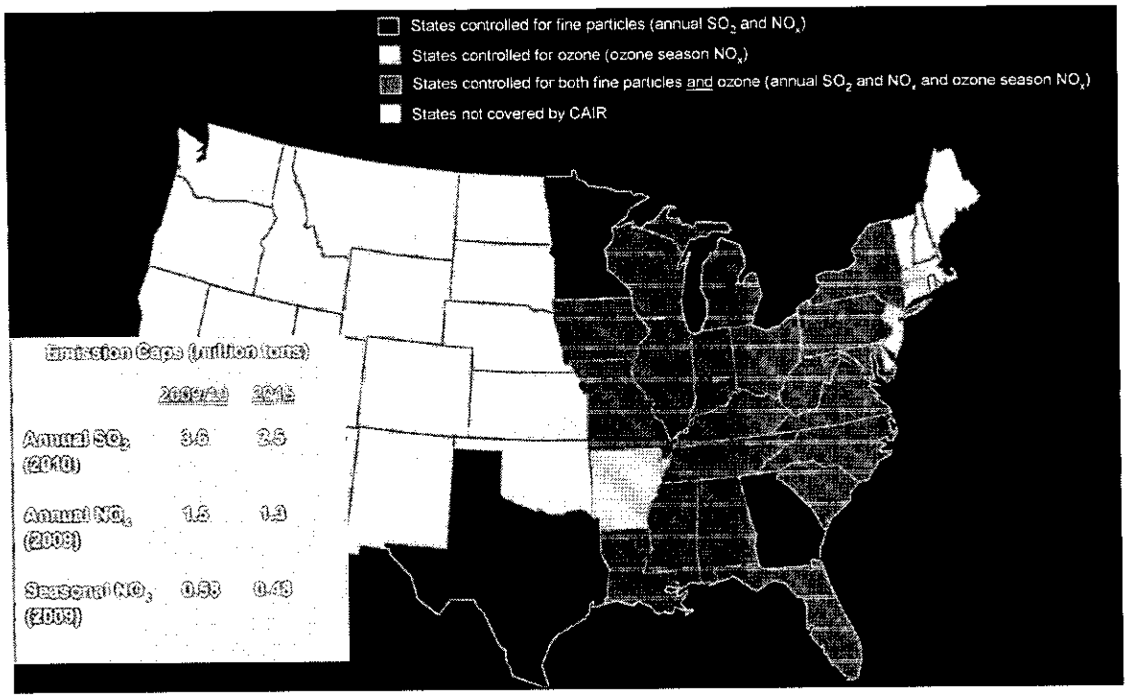
7.8. Environmental Regulations

Description. For thermal generating units, variable operating and maintenance costs associated with installed scrubbers (SO_2 reduction) or with Selective Catalytic Reduction (SCR) processes for NO_x reduction are included in the marginal production cost and the unit energy bids. No fixed or capital costs of these emission control technologies are included in the calculation of marginal cost. CRA tracks industry announcements of units that are planning to install NO_x or SO_2 abatement technologies in the near future and models the resulting changes in emission rates and the variable and fixed costs associated with the new installations.

To account for SO_2 trading under EPA's Acid Rain Program, the model incorporates the opportunity cost of SO_2 tradable permits into the marginal cost bids, based on unit emission rates and forecast allowance trading prices for the time period of the simulation.

CRA models NO_x and SO_2 emission rates for all units where such data is available. In addition, CRA models compliance with various allowance trading programs, and attempts to capture the effect of future environmental regulations. All plant emission rates are drawn from the Emissions Scorecard published by the US Environmental Protection Agency. Emission rates for NO_x and SO_2 are obtained from industry futures, in particular those published by the Cantor Environmental Brokerage. CRA used its in-house NEEM model to forecast NO_x and SO_2 permit prices in the long run following the Clean Air Interstate Rules (CAIR) issued by EPA in March 2005. Implications of CAIR rules vary geographically as shown in Figure 1.

Figure 1. Geography of CAIR rules



Source: EPA

The forecast of emission allowance prices for NO_x and SO_2 are presented in Table 11 below. CRA does not include the impacts of Carbon or Mercury emissions in these simulations.

Table 11: Forecast Emission Allowance Prices

	Non-CAIR SO2 ($/Ton)	CAIR SO2 ($/Ton)	NOx ($/Ton)
2008	615	615	1450
2012	397	794	1665
2017	363	1039	2051

Data Sources. The EPA's Clean Air Markets Emissions Scorecard provides plant heat input, NO_x and SO_2 emissions, and emission rates. Capital costs for NO_x abatement technology are obtained from EPA's Regulatory Impact Assessment report for the NO_x Budget Program, originally provided by Bechtel Corporation. 2008 emission permit prices are obtained from a Cantor Fitzgerald on-line resource. Allowance price forecasts for 2012 and 2017 are developed by CRA using the NEEM Model.

7.9. External Region Supply

CRA explicitly models the US portion of the Eastern Interconnect and the Canadian province of Ontario. Regions outside this study area are modeled as either supply profiles or scheduled interchanges. CRA uses historic flows, combined with expectations of future conditions in these areas to project quantities and prices of power exchanged with the model footprint. In this analysis, flows from New Brunswick to New England, and from Hydro Quebec to New England, New York, and Ontario are modeled as scheduled flows, based on 12 months of historical data.

The DC ties with the WECC and ERCOT interconnections are modeled as price sensitive supply curves. CRA uses historical electricity prices and gas prices near these DC ties to calculate market heat rates for on-peak and off-peak periods, and for summer and winter. These heat rates are multiplied by the appropriate forecast gas price in each scenario, to arrive at a price points for each DC tie. The tie is then modeled as follows:

- When the locational price at the DC tie is within ± $2.50/MWh of the corresponding price point, zero flow is assumed on the tie.
- At locational prices that are between $2.50/MWh and $7.50/MWh above the price point, the tie is modeled as importing power into the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $7.50/MWh above the price point, the tie is modeled as importing power into the Eastern Interconnect at full capacity.
- At locational prices that are between $2.50/MWh and $7.50/MWh below the price point, the tie is modeled as exporting power from the Eastern Interconnect at half its capacity.
- At locational prices that are greater than $7.50/MWh below the price point, the tie is modeled as exporting power from the Eastern Interconnect at full capacity.

7.10. Dispatchable Demand (Interruptible Load)

Description. The presence of demand response is important to the energy and installed capacity markets. The value of energy to interruptible load caps the energy prices, and the capacity of interruptible load effectively replaces installed reserves and lowers the capacity value. For this study, the size of interruptible load is determined as a percentage of total load, based on Interruptible Demand and Direct Control Load Management as reported in the EIA-411 data. The dispatchable demand for each load area is modeled as a generator with a dispatch price of $600/MWh for the first block (50% of the area's dispatchable demand) and $800/MWh for the second block. These proxy units rarely run in the model, because the high prices they require indicate a supply shortfall and prompt new entry. Thus they play an insignificant role in the energy market, but they play an important role in the capacity market. If these loads can truly be interrupted during peak hours, they will be paid the capacity market-clearing price. Thus they have strong incentives to make themselves available during peak hours. When interruptible demand is included in the calculation of the required reserve margin, it reduces the requirement of installed capacity and thus reduces new entry and helps increase energy prices, consistent with market behavior.

Data Sources. Data were drawn from the EIA-411 report data.

7.11. MARKET MODEL ASSUMPTIONS

Marginal Cost Bidding. All generation units are assumed to bid marginal cost (opportunity cost of fuel plus non-fuel VOM plus opportunity cost of tradable emissions permits). To the extent that markets are not perfectly competitive, the modeling results will reflect the lower bound on prices expected in the actual markets.

Operating Reserves Requirement (spinning and standby). Operating reserves are based on requirements instituted by each reliability region. These requirements are based on the loss of the largest single generator, or the largest single generator and half the second largest generator, or a percentage of peak demand. The spinning reserves market affects energy prices, since units that spin cannot produce electricity under normal conditions. Energy prices are higher when reserves markets are modeled. Table 12 shows a list of operating reserves by reliability region, and the fraction met by spinning reserves. The remainder is assumed to be met by quick start reserves.

Table 12: Operating Reserve Requirements

ISO/Region	Operating Reserve	Met by Spin
ISO-NE	1,900 MW	67%
NYISO	1,200 MW	50%
Eastern NY	1,200 MW	25%
Long Island	120 MW	50%
PJM	4,500 MW	67%
Midwest ISO	2,250 MW	65%
MAPP	871 MW	65%
SPP	1,746 MW	65%
MIPU stand alone	85 MW	65%
Entergy	4% of load	65%
Southern	4% of load	65%
TVA	4% of load	65%
VACAR	4% of load	65%
FRCC	853 MW	65%
Ontario	1,600 MW	55%

Transmission Losses. Transmission losses are modeled at marginal rates.

7.12. Wheeling Rates

Wheeling rates are "per MWh" charges for moving energy from one control area to another in an electric system. In MAPS, wheeling rates are applied to net interregional power flows and are used by the optimization engine in determining the most economically efficient dispatch of generating resources to meet load in each model hour. Wheeling rates are considered for both commitment and dispatch of generating units; however, the rates between any two areas may be different for commitment than for dispatch. For the current analysis, the wheeling rates for commitment were based on the day-ahead firm transmission rates in the individual companies' tariffs, while the rate for dispatch was based on the non-firm hourly rates.

Table 13 gives an overview of the wheeling rates between SPP, MISO, Aquila and other neighboring control areas for the Stand-alone and RTO cases

Table 13: Wheel-out Rates for SPP, Midwest ISO and Aquila Missouri

From	To	Commitment	Dispatch
Midwest ISO	SPP	$6	$4
SPP (other than Westar)	Non-SPP	$2	$2
Westar	Non-SPP	$5	$3
Midwest ISO	PJM	$0	$0
Midwest ISO	Non-Midwest ISO/Non-SPP/non-PJM	$2	$2
Aquila Missouri Stand-alone	All	$2	$2
Non-Midwest ISO MAPP companies	All	$2	$2
AECI	All	$2	$2
TVA	All	$2	$2
Entergy	All (including SPP)	$2	$2
LG&E	All	$2	$2
Cleco	All (including SPP)	$2	$2

7.13. Fuel Prices

Description. MAPS requires monthly fuel prices for each generating unit in the model footprint. The fundamental assumption concerning participant behavior in competitive energy markets is that generators will bid their marginal cost into the energy market, including the marginal cost of fuel, variable operations and maintenance (O&M) and the costs associated with marginal emission of pollutants. The marginal cost of fuel is defined as either the opportunity cost of fuel purchased or the spot price of fuel at a location representative of the plant. If the fuel is purchased on a long term contract, it assumed that the opportunity cost of the fuel is the same as the price of fuel on the locational spot market.

CRA uses forecasts of spot prices at regional hubs, and refines these prices on the basis of historical differentials between price points and their associated hubs. For fuel oil and coal, CRA uses estimates of the delivered price of fuel to generators on a regional basis. Dual-fuel generators are simulated as follows:

Natural Gas Primary. Units that primarily burn natural gas may burn fuel oil in at most one month of the year. Because natural gas prices are typically highest in January, the model allows the unit to switch to fuel oil for January if the oil price at that location is lower than the natural gas price.

Fuel Oil Primary. Units that primarily burn oil may switch to natural gas whenever it is economically justified. CRA assumes that natural gas shortages prevent this from happening in the winter heating period, defined as November though March. A heat rate degradation of 3% is modeled when the unit switches to natural gas. Thus, the fuel type is switched to natural gas during April through October, whenever the price of natural gas plus 3% is less than the price of fuel oil.

Coal prices are drawn from a database provided by Resource Data International (RDI), which forecasts delivered coal prices, including transportation and handling, for each major coal plant in the United States. Nuclear plants are assumed to run whenever available, so nuclear fuel prices do not impact commitment and dispatch decisions in the market simulation model. CRA therefore does not do a detailed analysis of nuclear fuel prices.

Specific oil and gas price forecasts used in this study are provided in the next section.

7.14. NATURAL GAS AND FUEL OIL PRICE FORECAST

7.14.1. Natural Gas Forecast

Principal Drivers: The principal drivers are the projected prices for natural gas at Henry Hub.

Base Case Forecast: In the near term (through 2012), the Base Case forecast is set equal to NYMEX futures prices for natural gas at Henry Hub as of the closing of December 6, 2006. For 2013 through 2025, CRA uses the EIA Annual Energy Outlook (AEO2006) Reference Case forecast[28]. CRA Base Case forecast for natural gas prices at Henry Hub is shown in Figure 2.

Regional Prices: CRA forecasts natural gas prices on a regional basis following major pipeline traded pricing points. Regional forecasts are derived by adding two factors, the basis differential by region and local delivery charge by state, to the Henry Hub gas price.

28 AEO 2006 does not forecast Henry Hub Prices, but predicts prices at the wellhead instead. A historical multiplication factor of 1.129 is used to derive the Henry Hub price forecast.

Basis Differentials by Region: CRA recognizes multiple pricing points within each census region, all of which are actual pipeline trading points surveyed and reported by Platt's Gas Daily. Some of these pricing points coincide with the NYMEX Clearport hubs, which include Henry Hub. For the other points, CRA uses a regression model to one or several NYMEX Clearport hubs, calibrated with historical data, to derive a forecast. In the near term (through 2011), the basis forecast is derived from NYMEX Clearport hub futures settlement as of December 6, 2006. The NYMEX Clearport hub futures settlement data are only available for a short period, typically between 12 and 24 months. Within this time frame, CRA derives summer and winter differentials to these hubs using NYMEX data. Beyond this period, CRA scales the basis differentials in proportion to the Henry Hub forecast. Forecast prices at each hub are derived using the Henry Hub forecast and the scaled basis differential for that hub.

Local Delivery Charges: Burner tip prices for natural gas are the sum of the basis differentials by region as derived above and a local component that captures pipeline lateral charges and/or charges to local distribution companies. CRA estimates this local component at $0.07/MMBtu for all units. For older units CRA estimates extra LDC charges derived from AGA statistics.

Seasonal Pattern: Natural gas prices are varied seasonally based on NYMEX futures data in the near term (through 2012). Beyond 2012, the seasonal pattern shown in 2012 is repeated for each year.

Figure 3 compares the Base Case gas price forecast by region.

Figure 2. Henry Hub Prices, History and Forecast (in real 2005 $/MMBtu)

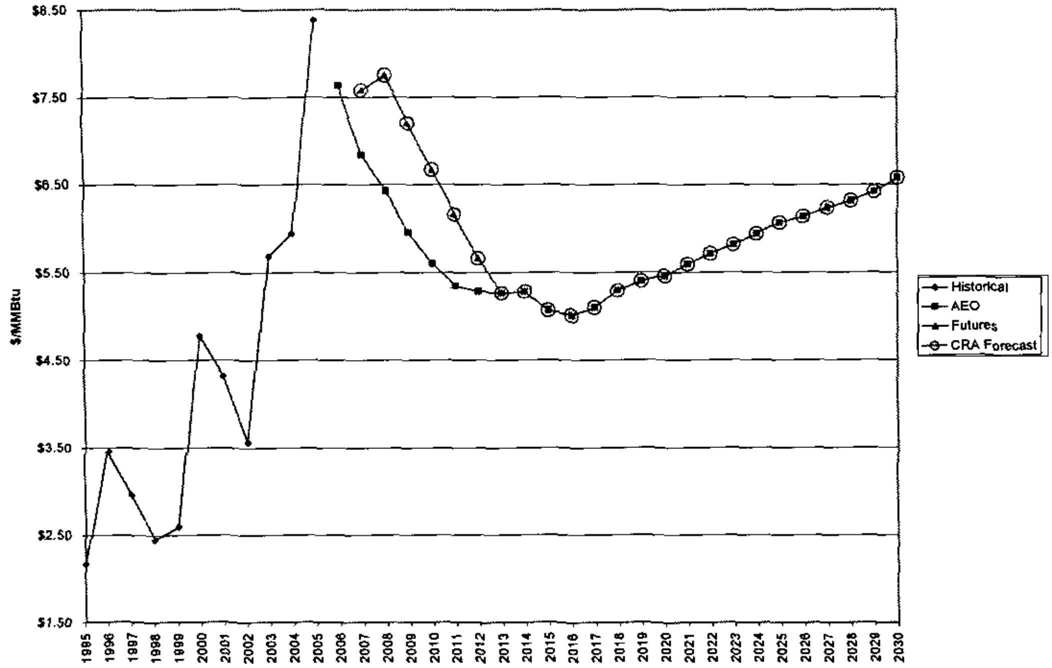
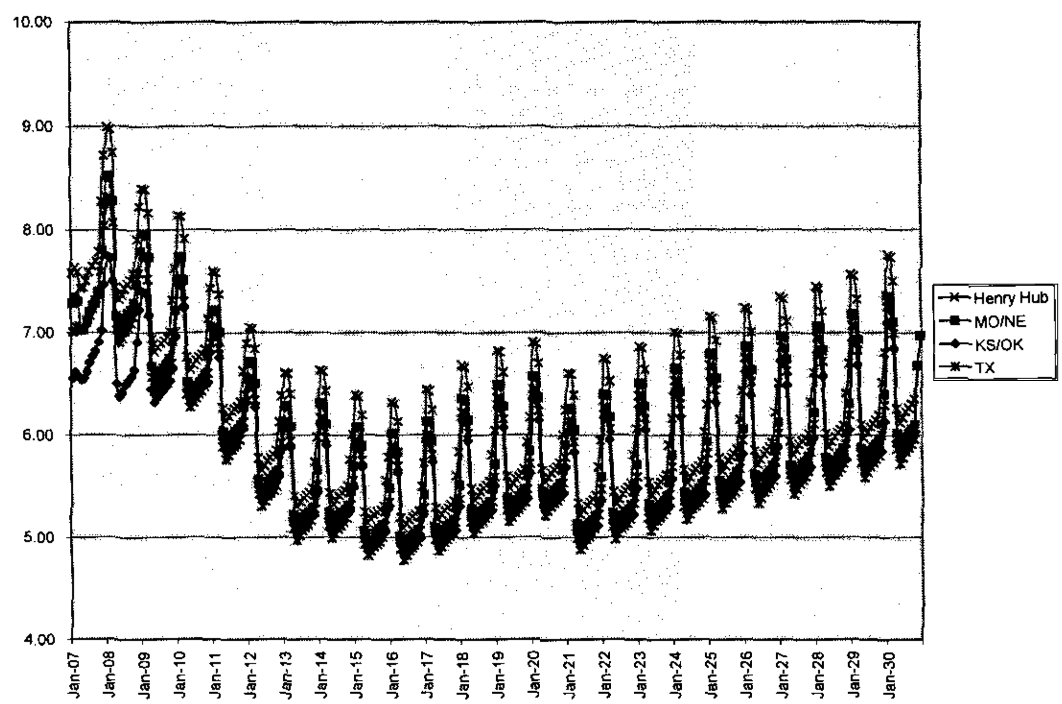


Figure 3. Forecast Regional Natural Gas Prices (Real 2005 $/MMBtu)



7.14.2. Fuel Oil Price Forecast

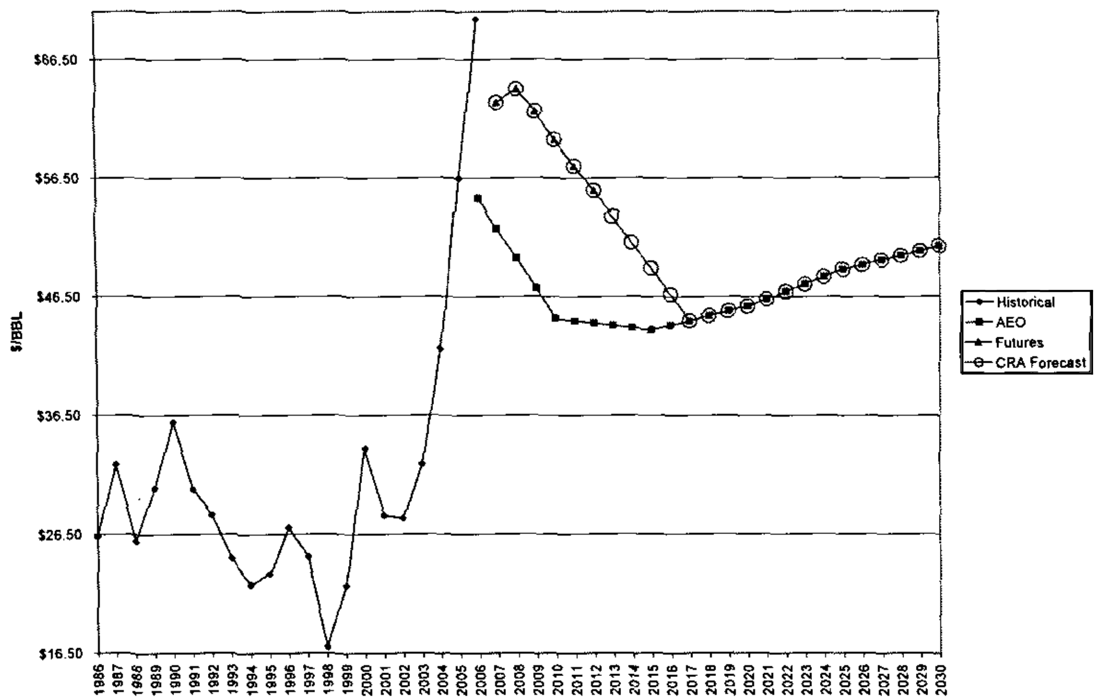
Principal Drivers: The principal drivers underlying this forecast are the projected price for light sweet crude oil at Cushing, Oklahoma.

Base Case Forecast: In the near term (through 2012), the Base Case forecast is derived from the NYMEX futures prices for light sweet crude oil as of the closing of December 6, 2006. For 2013, 2014 and 2015 the forecast is an interpolation between the futures and the AEO2006. Through 2030, CRA uses the AEO2006 Reference Case forecast. CRA Base Case forecast for light sweet crude oil is presented on Figure 2.

Regional Prices: CRA forecasts prices for fuel oil #2 and #6 by US census region. This forecast is prepared in three steps. First CRA uses a regression model calibrated on historical data to derive prices for fuel oil #2 and #6 at New York Harbor from the forecast of crude oil prices. New York Harbor prices for the Base Case forecast are shown in Figure 5. Second, New York Harbor prices (both fuel oil #2 and fuel oil #6) are linked to the AEO Reference Case forecast of US average prices of each type of fuel oil used by electric utilities. This derivation is also based on historical regression. Finally, CRA uses AEO forecast to develop yearly regional multipliers linking national average prices and prices by census region. Petroleum Business Tax of $0.45/MMBtu for fuel oil #6 and $0.63/MMBtu for fuel oil #2 is added to oil prices for New York State.

Seasonal Pattern: Both fuel oil #2 and fuel oil #6 prices are varied monthly based on NYMEX futures data in the near term, and based on historical monthly patterns in the longer term.

Figure 4. Crude Oil Prices: History and Projection (Real 2005 $/BBL)



7.15. NATURAL GAS PRICE SENSITIVITY ASSUMPTION

A natural gas price sensitivity case was performed for the year 2012 in which the Henry Hub natural gas prices shown in Figure 2 were increased to $9.00 per mmBTU (2005$). The 2012 generation fuel prices were then recreated using the methodology discussed above. No changes were made to fuel oil, coal or nuclear fuel prices.

8. APPENDIX B: AQUILA MISSOURI RESOURCES

Table 14 lists the Aquila Missouri generation resources for the 2008 to 2017 period. The jointly-owned units and the long-term unit purchases are located outside of the Aquila Missouri control area.

Table 14
Aquila Missouri Generating Capacity

(MW, summer rating)

Existing Units		
Greenwood 1-4	232.0	
Iatan 1	117.7	*Jointly-owned*
Jeffrey 1-3	175.2	*Jointly-owned*
KCI 1-2	33.6	
Lake Road 1-7	268.8	
Nevada	20.0	
Ralph Green	71.0	
Sibley 1-3	508.3	
South Harper	315.0	
	1741.6	
Long-term Purchases		
Cooper	75.0	*Ends May 2011*
Gentleman 1-2	100.0	*Ends Jan. 2014*
	175.0	
New Capacity		
Iatan 2	153.0	*2010 ISD, Jointly-owned*
Merchant Capacity in Aquila-Mo Control Area		
Aries	580.0	

9. APPENDIX C: SUPPORTING DETAIL

9.1. ANNUAL RESULTS

9.1.1. Member of Midwest ISO

The projected annual benefits (costs) to Aquila Missouri of being a member of the Midwest ISO for each category of benefits and costs are summarized in Table 15.

Table 15
Annual Benefits (Costs) to Aquila Missouri of Midwest ISO Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

	Present Value	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Aquila-MO in Midwest ISO											
+ Production Cost Savings	**45.9**	2.9	3.6	4.3	5.1	5.9	7.5	9.1	10.8	12.6	14.5
+ Purchase Cost Savings	**(103.5)**	(11.4)	(12.7)	(14.1)	(15.5)	(17.0)	(17.2)	(17.4)	(17.7)	(17.9)	(18.1)
+ Sales Revenue Increases	**87.6**	15.3	15.2	15.1	14.9	14.8	13.2	11.6	9.9	8.1	6.2
= Trade Benefits	**29.9**	6.8	6.1	5.3	4.5	3.7	3.5	3.3	3.0	2.8	2.5
+ Savings Trans/Rel Functions	**16.0**	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7
+ RTO Administative Charges	**(23.5)**	(3.3)	(3.2)	(3.3)	(3.4)	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)	(4.0)
+ Additional FERC Charges	**(1.3)**	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
= Subtotal Other Charges	**(8.8)**	(1.3)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.5)
Total	**21.1**	5.5	4.9	4.1	3.3	2.4	2.2	1.9	1.6	1.3	1.0

9.1.2. Member of SPP RTO

The projected annual benefits (costs) to Aquila Missouri of being a member of the SPP RTO for each category of benefits and costs are summarized in Table 16.

Table 16
Annual Benefits (Costs) to Aquila Missouri of SPP RTO Membership in comparison to Stand-alone Status
(in millions of dollars; positive numbers are benefits)

	Present Value	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
Aquila-MO in SPP RTO											
+ Production Cost Savings	**673.4**	80.2	85.0	90.0	95.2	100.7	105.9	111.4	117.1	123.0	129.1
+ Purchase Cost Savings	**(465.5)**	(49.4)	(53.3)	(57.3)	(61.5)	(65.8)	(73.1)	(80.7)	(88.7)	(97.0)	(105.7)
+ Sales Revenue Increases	**(112.2)**	(16.1)	(16.7)	(17.4)	(18.0)	(18.7)	(17.8)	(16.8)	(15.8)	(14.7)	(13.6)
= Trade Benefits	**95.7**	14.7	15.0	15.4	15.8	16.1	15.0	13.8	12.6	11.2	9.8
+ Savings Trans/Rel Functions	**16.0**	2.2	2.2	2.3	2.3	2.4	2.5	2.5	2.6	2.6	2.7
+ RTO Administative Charges	**(23.5)**	(3.3)	(3.2)	(3.3)	(3.4)	(3.5)	(3.6)	(3.7)	(3.8)	(3.9)	(4.0)
+ Additional FERC Charges	**(1.3)**	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)	(0.2)
= Subtotal Other Charges	**(8.8)**	(1.3)	(1.2)	(1.2)	(1.3)	(1.3)	(1.3)	(1.4)	(1.4)	(1.4)	(1.5)
Total	**86.9**	13.4	13.8	14.2	14.5	14.8	13.7	12.5	11.2	9.8	8.3

9.2. ADMINISTRATIVE AND OPERATING COSTS

9.2.1. Savings from RTO Provision of Transmission Functions

At the request of CRA, Aquila Missouri staff estimated the additional costs that Aquila Missouri would incur to provide on a Stand-alone basis the six transmission/reliability functions currently provided by SPP and the Midwest ISO on a Stand-alone basis. These costs would be avoided (and replaced by RTO administrative charges) if Aquila Missouri were to join an RTO. The key assumptions behind the cost figures are summarized below.

Function 1. Reliability Coordination

For Aquila Missouri to provide its own reliability functions (the direct actions required to maintain adequate generation capacity, adequate system voltage levels, and transmission system loading within specified limits), five additional FTE system operators would be required along with a $205,000 investment in additional computer hardware/software. Also there would be approximately $10,000 per year needed for software licensing/maintenance fees.

Function 2. Tariff Administration

In order to provide tariff administration such as processing long term transmission service requests, performing feasibility and impact studies, managing billing, and handling regulatory issues would require addition of one FTE planning engineer.

Function 3. OASIS Administration

This function comprises administration of transmission service, including provision of qualified staff and supervision for day and night coverage and procurement and maintenance of the necessary telecommunications infrastructure to support the service. Information updated would include ATC, response to service requests, transmission limitations, transmission reservation policy, and various FERC required postings. To maintain the OASIS on a full time basis would require three additional FTE system operators in the system operations area. In addition a capital investment of approximately $15,000 would be required for additional computer equipment and software.

Function 4. ATC/TTC Calculations

In order to perform required transmission capacity calculations, one FTE planning engineer would be required.

Function 5. Scheduling Agent

For Aquila to perform this service, two clerical FTEs would be required to check out all transactions with customers on a daily basis, and in addition two FTE system operator would be required to track and administer tags on a daily basis.

Function 6. Regional Transmission Planning

The transmission planning function would consist of developing load flow planning models with a 10 year horizon, developing a database and performing stability studies, performing transmission expansion and operating studies, develop transmission pricing models. Part of this work is already performed by Aquila transmission planning personnel. To assume the planning study work now done by SPP would require the addition of one FTE planning engineer.

Aquila Missouri personnel provided O&M (including benefits) and capital addition costs for the years 2008 through 2017. CRA converted the capital additions into revenue requirements, and also applied an A&G adder to the projected wages as shown in Table 17.

Table 17
Annual Costs for Aquila Missouri to Provide Transmission/Reliability Functions
(in thousands of dollars)

	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017
1 Reliability Coordination										
Wages	390	399	409	419	430	441	452	463	475	486
Benefits	195	200	205	210	215	220	226	231	237	243
Other O&M	10	11	11	11	11	12	12	12	12	13
Total O&M	595	609	625	640	656	673	689	707	724	742
Capital Additions	210					238				
2 Tariff Administration										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
3 OASIS Administration										
Wages	234	240	246	252	258	264	271	278	285	292
Benefits	117	120	123	126	129	132	136	139	142	146
Other O&M	5	5	5	5	4	6	6	6	5	5
Total O&M	356	365	373	382	391	403	412	422	432	443
Capital Additions	15					15				
4 ATC/AFC/TTC Calculations										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
5 Scheduling Agent										
Wages	238	244	250	256	262	269	276	283	290	297
Benefits	119	122	125	128	131	135	138	141	145	148
Total O&M	357	366	375	384	394	404	414	424	435	445
6 Transmission Planning										
Wages	72	74	75	77	79	81	83	85	87	90
Benefits	36	37	38	39	40	41	42	43	44	45
Total O&M	108	110	113	116	119	122	125	128	131	134
TOTAL										
Wages	1076	1103	1131	1159	1188	1218	1248	1279	1311	1344
Benefits	538	552	565	580	594	609	624	640	656	672
Other O&M	16	16	16	16	16	18	18	18	18	18
A&G (a)	473	485	497	510	522	535	549	563	577	591
Total O&M and A&G	2103	2156	2209	2264	2320	2380	2439	2499	2561	2625
Capital Additions										
Capital Additions	225					253				
Rev Requirement	78	71	65	58	52	87	80	72	65	58
Total	2181	2227	2274	2322	2372	2467	2519	2572	2627	2683

(a) *Estimated at 44% of Wages based on Aquila-MO 2004/5 FERC Form 1 Ratio of A&G Office Supplies and Expenses to A&G Salaries*

9.2.2. RTO Administrative Costs

The annual RTO administrative costs were estimated using the forecast of expenditures per MWh of market member load as projected by the Midwest ISO as shown in Table 18. Aquila Missouri expenditures subsequent to 2011 were assumed to escalate at inflation.

Table 18

Annual RTO Administrative Charges for Aquila Missouri

RTO Administrative Charges						
			2008	**2009**	**2010**	**2011**
Aquila-MO Net Annual Energy	(GWh)	(a)	8,823	9,074	9,322	9,572
RTO Administative Charges	($/MWh)	(b)	0.373	0.358	0.356	0.356
Aquila-MO RTO Admin Charges	($000)		3,291	3,248	3,319	3,408

(a) - SPP 2006 IE-411, page 24.
(b) - Midwest ISO, Recommended Capital and Operating Budget, December 14, 2006, page 5.

9.2.3. Additional FERC Charges

The annual additional FERC charges in 2007 dollars that would be incurred by Aquila Missouri if a member of an RTO are provided in Table 19. The additional cost was assumed to increase at inflation through the study period.

Table 19: Additional FERC Annual Charges if in RTO
(in thousands of dollars unless noted)

Historical FERC Charges for Aquila-Missouri						
(Source: FERC Form 1, Page 350, Regulatory Commission Expenses)						
	MPS	**L&P**	**Total**	**2007$ (c) Multiplier**	**2007$ Total**	
2004	148.8	120.2	269.0	1.0875	292.6	
2005	91.5	111.8	203.3	1.0549	214.4	
Average					**253.5**	
FERC Charges if in RTO:						
2007 MISO Estimated Schedule 10 FERC Charges (a)					32,333	(a)
2007 MISO Estimated Schedule 10 GWH (load)					650,847	
2007 FERC Charges per $/MWh of load					0.050	
Aquila-MO 2007 Estimated Net Energy for Load (GWh)					8,586	(b)
Aquila-MO 2007 Annual FERC Charge if in RTO					**426.5**	
Increase in FERC Charges if in RTO (2007$)					**173.0**	

(a) - Midwest ISO, Schedule 10 FERC Rate, forecast 2007 dollars for MISO
(b) - SPP 2006 IE-411, page 24.
(c) GDP Deflator:

7/1/2004	*109.728*	
7/1/2005	*113.121*	
7/1/2006	*116.420*	
7/1/2007	*119.331*	*@2.5%*

Aries Generation by Case

As discussed at the May 31 stakeholder meeting, the Aries unit generates less in the SPP case than in the Midwest ISO case. CRA has reviewed the commitment and dispatch of the Aries unit to confirm that the MAPS model is working correctly. Based on this review, the higher generation of Aries in the Midwest ISO case in the MAPS modeling is driven largely by two inter-related factors.

The first is the relative level of natural gas prices in Missouri for the Aries unit with respect to the level of gas prices elsewhere in the SPP and elsewhere in the Midwest ISO. Gas prices are somewhat lower in Missouri and thus for the Aries CC relative to other CCs in the Midwest ISO. In contrast, the Missouri-Aries CC gas prices are somewhat higher than the gas prices in most other areas of SPP.

The second factor is the combination of transmission limitations and seams charges. The transmission inter-tie capacity between Aquila and the Midwest ISO (Ameren) is relatively small in comparison to the capacity between KCPL and Aquila Missouri. In the SPP case, there are no seams charges across the significant inter-ties between KCPL and Aquila Missouri. In the Midwest ISO case, there are significant seams charges across these same KCPL and Aquila inter-ties.

The combination of gas prices, transmission limitations and seams charges results in Aries being committed and dispatched more often in the Midwest ISO case in the MAPS modeling. In the SPP case, Aquila is able to import additional power from SPP at marginal prices less than the Aries generation. In the Midwest ISO case, seams charges decrease the ability of SPP units to economically meet this Aquila load, and gas prices differences and transmission limitations between Aquila and the rest of the Midwest ISO are such that Aries is more often the least cost alternative.

Aquila Missouri Annual Generation, Purchases, Sales (GWh)

	2008 StAlone	2008 In MISO	2008 In SPP	2012 StAlone	2012 In MISO	2012 In SPP	2017 StAlone	2017 In MISO	2017 In SPP
I. With Aries Included in Generation									
+ Generation, incl. Aries (a)	9,149	9,055	7,825	9,928	9,670	7,756	10,483	10,102	7,921
+ Purchases, excl. Aries	365	713	1,324	538	1,095	2,326	1,161	1,658	3,491
- Sales	494	748	130	406	705	20	270	386	38
= Net	9,020	9,019	9,020	10,060	10,060	10,062	11,375	11,374	11,375
Increase Relative to Standalone									
+ Generation		(94)	(1,324)		(258)	(2,173)		(381)	(2,562)
+ Purchases		348	959		556	1,788		497	2,330
- Sales		254	(364)		299	(386)		116	(232)
Aries Generation	1,533	1,413	231	2,263	2,124	564	3,239	2,939	1,054
II. With Aries Included in Purchases									
+ Generation, excl. Aries	7,615	7,642	7,594	7,665	7,546	7,192	7,244	7,162	6,868
+ Purchases, incl. Aries	1,899	2,126	1,556	2,801	3,219	2,890	4,400	4,597	4,545
- Sales	494	748	130	406	705	20	270	386	38
= Net	9,020	9,019	9,020	10,060	10,060	10,062	11,375	11,374	11,375
Increase Relative to Standalone									
+ Generation		26	(22)		(119)	(474)		(82)	(376)
+ Purchases		227	(343)		417	89		197	145
- Sales		254	(364)		299	(386)		116	(232)

(a) - Includes jointly-owned units and unit purchases outside of the Aquila-Missouri control area and merchant generation inside the Aquila-Missouri control area