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October 7, 2005

BY HAND DELIVERY
The Honorable Magalie Roman Salas
Secretary
Federal Energy Regulatory Commission
888 First Street, N.E.
Washington, D.C. 20426

RE:

LG&E Energy LLC,
Docket No. ER06-___-000

Louisville Gas and Electric Company, *et al.*,
Docket No. EC98-2-___

Louisville Gas and Electric Company, *et al.*
Docket No. EC00-67-___

E.ON AG, *et al.*
Docket No. EC01-115-___

Dear Secretary Salas:

Pursuant to Sections 203 and 205 of the Federal Power Act ("FPA"), 16 U.S.C. §§ 824b & 824d (2000), and Parts 33 and 35 of the Rules of Practice and Procedure of the Federal Energy Regulatory Commission ("FERC" or the "Commission"), 18 C.F.R. Parts 33 & 35 (2005), LG&E Energy LLC, together with and on behalf of its public utility operating company subsidiaries Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Applicants"), hereby tender this filing seeking Commission approval to change Applicants' method of: (i) complying with Order Nos. 888 and 889, and certain conditions imposed by the Commission in the context of Applicants' prior mergers; and (ii) achieving the goals of Order No. 2000.

STATEMENT OF ISSUES (18 C.F.R. § 385.203)

1. Applicants request that the Commission accept for filing certain rates, terms, and conditions necessary for them to:

   a. Withdraw from the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") and regain operational control of their respective transmission systems;

   b. Install a third party certified by the North American Electric Reliability Council ("NERC") to act as reliability coordinator ("Reliability Coordinator") for their transmission facilities subject to the jurisdiction of the Commission ("Transmission System"); and

c. Install an independent third party to act as tariff administrator for their transmission system ("Independent Transmission Organization" or "ITO"); and

2. Applicants request a Commission finding under FPA Section 203 that their withdrawal from the Midwest ISO (together with the operation and administration of their Transmission System by the ITO and Reliability Coordinator) satisfies certain Merger Conditions[1] proposed by Applicants and approved by this Commission in the above-captioned "EC" dockets ("Merger Conditions").

As explained in Part VII below, Applicants request privileged treatment, pursuant to 18 C.F.R. § 388.112, for certain of the workpapers of witness William H. Hieronymus, as contained on one of the two enclosed CD-ROMs.

I. EXECUTIVE SUMMARY, INTRODUCTION AND OVERVIEW OF FILING

In this filing, Applicants seek authority to withdraw from the Midwest ISO and to delegate transmission reliability coordination and tariff administration functions to certain third parties. This filing is the culmination of several years of analysis conducted by Applicants regarding their membership in the Midwest ISO, as directed by the Kentucky Public Service Commission ("KPSC").[2] In testimony attached hereto (Exhibit B), Paul W. Thompson, Senior Vice President of Energy Services for LG&E Energy LLC, provides an overview of the filing. In addition, Mr. Thompson explains Applicants' reasons for becoming charter members of the Midwest ISO, the reasons that Applicants now seek to exit the Midwest ISO, and an explanation of why Applicants' withdrawal will not harm the Midwest ISO.

The body of this filing is divided into five parts:

First, Part II identifies the contents of this filing, including all exhibits hereto.

Second, Part III presents relevant background information, including: a description of the Applicants, the Merger Conditions, a history of Applicants' participation in the Midwest ISO, and a description and overview of KPSC proceedings investigating Applicants' continued membership in the Midwest ISO.

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[1] *See Louisville Gas & Elec. Co. and Kentucky Utilities Co.*, 82 FERC ¶ 61,308 at 62,222-23 (1998) ("LG&E/KU Merger Order"); *Louisville Gas & Elec. Co. and Powergen LLC*, 91 FERC ¶ 61,321 (2000) ("Powergen Merger Order"); *E.ON AG*, 97 FERC ¶ 61,049 at 61,283 (2001) ("E.ON Merger Order").

[2] *See, e.g., Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, KPSC Case No. 2003-00266, Order issued July 17, 2003.

Third, in Part IV, Applicants request that the Commission accept certain rates for filing under FPA Section 205, including: (i) the removal and withdrawal of Applicants from the Agreement of Transmission Facilities Owners to Organize the Midwest Independent System Operator, Inc. ("TO Agreement"); and (ii) a revised open access transmission tariff ("OATT") to implement the ITO/Reliability Coordinator proposal presented herein.[3]

As described below, Applicants have used a competitive bidding process to select the Tennessee Valley Authority ("TVA") as the Reliability Coordinator and the Southwest Power Pool, Inc. ("SPP") as the ITO.[4]

In Section IV.B.2, Applicants explain why TVA is well suited for serving as Reliability Coordinator. In addition, Applicants explain why SPP is the best candidate for serving as ITO. Applicants contend that transmission independence can be achieved and reliability can be enhanced in a more cost-efficient manner through the use of an ITO and a Reliability Coordinator as provided for herein. Applicants' RFP process and the functions to be undertaken by TVA, SPP, and Applicants are described in the attached testimony of Mark S. Johnson. In addition, the benefits of TVA acting as Reliability Coordinator for Applicants' Transmission System are described in the attached testimony of Stuart L. Goza of TVA.

In Part IV, Applicants also seek approval of their withdrawal from the TO Agreement, and explain how their proposed rates and De-Pancaking Maintenance Plan nullify any negative impacts on customers.

Fourth, Part V of this filing demonstrates that Applicants' withdrawal from the Midwest ISO, and implementation of an ITO and a Reliability Coordinator, provides a cost-effective alternative for satisfaction of the Merger Conditions. The determination of cost effectiveness is supported by the attached testimony of Dr. Mathew Morey. Also attached is testimony of Dr. William Hieronymus, who explains that, in his opinion, Applicants' proposal to implement an ITO and Reliability Coordinator is consistent with the Merger Conditions.

Fifth and finally, Part VI discusses how the ITO and the Reliability Coordinator will maintain the level of reliability which Applicants' customers have historically enjoyed. The

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[3] Contained in the OATT are the Applicants' *pro forma* agreements with the ITO and Reliability Coordinator, respectively. Applicants note that they are filing the *pro forma* reliability coordination agreement with TVA, as well as the TVA-applicable provisions of OATT Attachment L (establishing, among other things, the role of the Reliability Coordinator) for informational purposes. The reliability coordination agreement and TVA, in its role as reliability coordinator, do not fall within the Commission's jurisdiction.

[4] As of the date of this filing, Applicants have not concluded negotiations with TVA and SPP. Applicants will submit completed agreements, and any necessary information as amendments to this filing, as soon as possible.

benefits of TVA acting as Reliability Coordinator for Applicants' Transmission System are described in the attached testimony of Stuart L. Goza of TVA.

Overall, this filing demonstrates that Applicants will maintain the requisite level of independence with respect to the operation of their transmission system and administration of the OATT. The independence of the ITO and the lack of affiliation of the Reliability Coordinator with Applicants will prevent any exercise of vertical market power by Applicants. Moreover, in some ways, Applicants' filing seeks to implement a version of the Independent Coordinator of Transmission ("ICT") model recently approved in concept by the Commission.[5] The Commission has recognized that ICTs can be "a positive development towards [a] more independent" transmission regime by stepping "beyond the transmission service offered under [the] *pro forma* OATT and the underlying Order No. 888 principles."[6]

Applicants believe that their proposal complies with Order Nos. 888 and 889, and achieves the goals of Order No. 2000.[7] In this regard, in testimony attached hereto, former Commissioner Vicky A. Bailey explains that Applicants' proposal is consistent with and meets the Commission's policy goals set forth in Order Nos. 888, 889, and 2000. Commissioner Bailey, who is also a former commissioner with the Indiana Regulatory Utility Commission, explains why Applicants' proposal is an appropriate framework to satisfy both this Commission's and Kentucky's interests regarding regulation of a public utility with very low-cost power supplies in a non-retail choice state. In his testimony, Dr. Morey concludes that this ITO/Reliability Coordinator model "satisfies Order No. 888 requirements at lower cost than does RTO membership, leaves the Companies in control of their transmission and generation assets, maintains state regulatory authority and control over retail rates and costs, and gives the Commission a policy option that can advance Order No. 888 objectives with potentially less controversy than has attended the Commission's pursuit of Order No. 2000 and "full-service" RTOs."[8]

Applicants understand that this filing, which seeks authorization to withdraw from a Commission-approved RTO, presents issues of first impression. Applicants note that, in contrast to Applicants' situation, entities recently seeking approval of ICTs or similar independent

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5 *See Entergy Servs., Inc.*, 110 FERC ¶ 61,295 (2005) ("Entergy ICT Order").

6 *Id.* at P 65.

7 *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 (Jan. 6, 2000), FERC Stats. & Regs. P 31,089 at 31,174. (1999), *order on reh'g*, Order No. 2000-A, 65 Fed. Reg. 12,088 (Mar. 8, 2000), FERC Stats. & Regs. P 31,092 (2000), *aff'd sub nom. Public Utility District No. 1 of Snohomish County, Washington v. FERC*, 272 F.3d 607 (D.C. Cir. 2001).

8 Morey Testimony at 3.

entities have not been members of RTOs (*e.g.*, Entergy, MidAmerican and Duke Energy). Although the Commission could find that Applicants' RTO membership must always remain static, Applicants believe this approach would be somewhat shortsighted, especially given the fact that the Commission has not mandated RTO membership as a blanket requirement for public utilities. Thus, Applicants have merely identified and are seeking to implement a more cost-effective method for: (i) meeting the Commission's public policy goals of open transmission access and reliability; and (ii) satisfying the Merger Conditions.

It is of primary importance to Applicants that they meet the Commission's objectives for non-discriminatory, open access transmission service in the most cost-effective and efficient manner possible. Keeping rates down and maintaining reliability are Applicants' top priorities and are the motivating factors for this filing. As demonstrated in the testimony of Dr. Morey, Kentucky has some of the lowest retail electric rates in the nation.[9] These low rates are largely due to the use of coal-fired generation sold at cost-based rates,[10] the policies adopted by the Kentucky General Assembly, and sensible regulatory oversight by the KPSC.[11] Kentucky has studied from time to time the possibility of retail competition, and has consistently concluded that traditional regulation remains the best method of maintaining both reliability and low retail

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[9] *See* Morey Testimony at 7-9. On February 7, 2005, Kentucky Governor Ernie Fletcher issued an Executive Order directing the KPSC to examine the future needs for electricity in the Commonwealth. *See* Kentucky Public Service Commission, *Kentucky's Electric Infrastructure: Present and Future* at 9 (Aug. 22, 2005). The Governor specifically called for a plan that would promote investment in electric infrastructure, preserve the environment, and maintain Kentucky's "low-cost electric advantage" and low electric rates. *Id.* In response, the KPSC initiated a study and reported its findings in a report issued August 22, 2005. *See id.* In the report, the KPSC noted that Kentuckians pay the lowest electricity rates in the nation. *See id.* at 11, citing U.S. Department of Energy statistics for 2005 (average retail rate for electricity in Kentucky in 2005 is 4.47 cents per kilowatt-hour whereas the national average is 7.52 cents per kilowatt-hour). The KPSC found that these low rates were "the result of investment by Kentucky's utilities in large, coal-fired generating units- which generate 95 percent of Kentucky's electricity- combined with an abundant local fuel supply, sound utility management, and a statutory system that regulates the price jurisdictional utilities may charge for retail electricity." *Id.* at 4. The KPSC concluded that this "regulatory structure has enabled [Kentucky] to have the lowest cost power in the nation and that Kentucky should preserve its current statutory and regulatory framework, which focuses on the utilities' obligation to serve their customers within a defined service territory." *Id.* at 7.

[10] The three largest coal producing states (Wyoming, West Virginia, and Kentucky) have the three lowest electricity costs in the nation. *See* Kentucky Governor Ernie Fletcher, *Kentucky's Energy Opportunities for Our Future: A Comprehensive Energy Strategy* AT 2 (2005) <http://governor.ky.gov/NR/rdonlyres/8C9049CA-99AE-45E5-BD40-DC52FED6090D/0/energy.pdf>.

[11] The KPSC attributes the low electric rates to: (i) proximity to coal production sites; (ii) a state ban on costly nuclear generating units; (iii) beneficial corporate management and efficient operations by utility companies; and (iv) fair and reasonable regulation and oversight by state authorities. *See* Kentucky Public Service Commission, *Principles and Guidelines on the Restructuring of the Electric Industry* (1997) ("KPSC Guidelines on Restructuring").

electric rates.[12] In order to maintain low rates, Applicants have developed the present proposal, which complies with Order Nos. 888 and 889 and achieves the goals of Order No. 2000 in a more cost-effective manner.

In sum, Applicants demonstrate herein that this proposal is just and reasonable and provides a cost-effective alternative for meeting the Merger Conditions, thus satisfying the public interest standard. Accordingly, the Commission should accept Applicants' submittal for filing without suspension or hearing (to be effective upon Commission acceptance of the rates contained in this filing).

II. CONTENTS OF THIS FILING

This filing consists of this Application and the following supporting attachments:

- Exhibit A – Clean Version of Applicants' OATT, including new Schedules and Attachments;
- Exhibit A-1 – Chart Referencing Sources for Red-lining the OATT and the Red-lined Portions of the OATT;
- Exhibit B – Testimony of Paul W. Thompson;
- Exhibit C – Testimony of Dr. Mathew Morey;
- Exhibit D – Testimony of Dr. William Hieronymus;[13]
- Exhibit E – Testimony of Vicky A. Bailey;
- Exhibit F – Testimony of Mark S. Johnson;
- Exhibit G – Testimony of Stuart L. Goza;
- Exhibit H – Applicants' Notice of Withdrawal from the Midwest ISO;

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[12] In December 1997, the KPSC identified several principles to guide its consideration of restructuring the electrical industry. Among the KPSC's concerns were protecting consumers against undue discrimination and guaranteeing universal electric service at reasonable prices. *See* KPSC Guidelines on Restructuring. In 1998, the Kentucky General Assembly created the Electricity Restructuring Task Force. *See* HJR 95, 1998 Leg., Reg. Sess. (Ky. 1998) <http://www.lrc.ky.gov/recarch/98rs/HJ95.htm>.

[13] Dr. Hieronymus' workpapers are included on the two enclosed CD-ROMs.

- Exhibit I – TVA Reliability Area Maps;
- Exhibit J – Letter of Intent Between Applicants and TVA;
- Exhibit K – TVA Reliability Plans (*i.e.*, the TVA Reliability Plan approved by NERC in 2002, as well as the TVA Reliability Plan currently pending SERC, ECAR and NERC approval), List of Primary Responsibilities and Support Functions of ITO, Reliability Coordinator and Applicants, and Matrix of ITO-Reliability Coordinator-Applicants Responsibilities and Communications;
- Exhibit L – Joint Reliability Coordination Agreement with the Midwest ISO and PJM;
- Exhibit M – Relevant Portions of Attachment P of the Midwest ISO OATT;
- Exhibit N - Letter Indicating Status of Withdrawal Discussions
- Exhibit O – Service List; and
- Exhibit P – Notice of Filing.

III. BACKGROUND

A. Description of Applicants

LG&E and KU are Kentucky corporations, each primarily engaged in the generation, transmission, and distribution of electric energy in Kentucky. LG&E and KU are subsidiaries of LG&E Energy LLC ("LG&E Energy") which, in turn, is a subsidiary of E.ON AG ("E.ON"), a major multi-national energy company headquartered in Germany.

LG&E provides retail electric service to over 384,000 customers in a service area covering approximately 700 square miles in Kentucky, including the metropolitan Louisville area and 16 surrounding counties. LG&E also purchases, distributes, and sells natural gas to over 312,000 customers within Kentucky. In 1998, LG&E's parent company acquired KU, which provides regulated electric utility service to over 485,000 customers located in 77 Kentucky counties. Under the name Old Dominion Power, KU also provides retail electric service to over 29,000 retail customers located in five counties in Virginia.[14] Altogether, KU's

[14] In addition to its retail service in Kentucky and Virginia, KU provides electric service to approximately five customers in one county in Tennessee.

service territory covers 6,600 noncontiguous square miles. In addition to its retail service, KU also sells wholesale electric energy requirements service to 12 municipalities in Kentucky.

Applicants' retail rates and services in Kentucky are subject to the jurisdiction of the KPSC. In addition, KU's retail activities in Virginia are subject to the jurisdiction of the Virginia State Corporation Commission. Applicants also hold authorizations from FERC to make wholesale sales of power at market-based rates pursuant to their joint market-based sales service rate schedule.[15]

As discussed in greater detail below, Applicants are members of the Midwest ISO and are parties to the TO Agreement, which was accepted by FERC in 1998.[16] Applicants' transmission system is located on the southeastern edge of the Midwest ISO's regional footprint and is bordered by TVA to the south, the PJM Interconnection ("PJM") to the east, and Big Rivers Electric Corporation ("BREC") to the west.[17]

LG&E's and KU's total generation capacity is 3,699 megawatts and 5,030 megawatts, respectively.[18] Applicants self-generate the vast majority of electric power used to serve their retail customers, and are among the lowest-cost power producing utilities in the nation. Applicants also hold a distinguished record for reliability of electric service.[19] As utilities within and subject to the laws of Kentucky, Applicants are not authorized to offer retail customer choice but, instead, provide bundled electric service within franchised service territories.[20]

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[15] *Louisville Gas & Elec. Co.*, 85 FERC ¶ 61,215 (1998) (accepting for filing joint market-based rate tariff of LG&E/KU, FERC Electric Tariff, Original Volume No. 2); *LG&E Operating Cos.*, Docket No. ER99-1623-000, Letter Order, Jun. 4, 1999 (accepting revised tariff – FERC Electric Tariff, Original Volume No. 3 – for LG&E/KU permitting limited sales to certain affiliates).

[16] *See Midwest Indep. Transmission System Operator, Inc.*, 84 FERC ¶ 61,231, *order on reconsideration*, 85 FERC ¶ 61,250, *on reh'g*, 85 FERC ¶ 61,372 (1998), *Initial Decision*, 89 FERC ¶ 63,008 (1999), *aff'd and clarified*, Opinion No. 453, 97 FERC ¶ 61,033 (2001), *on reh'g*, Opinion No. 453-A, 98 FERC ¶ 61,141 (2002).

[17] Applicants are directly interconnected with the following entities: American Electric Power Corporation (member of PJM); Cinergy (member of Midwest ISO); Vectren (member of Midwest ISO); EKPC; BREC; Ohio Valley Electric Corporation; Electric Energy Incorporated; and TVA.

[18] These figures exclude KU's 20 percent interest in Electric Energy, Inc. (equivalent to 220 MW).

[19] In July 2005, LG&E was again awarded – for the sixth time in seven years – the distinction of being the most highly rated electric utility in the Midwest by consumers polled in an annual J.D. Power survey.

[20] *See, e.g., Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, KPSC Case No. 2003-00266, Order issued July 17, 2003.

B. Merger Conditions

On October 9, 1997, LG&E and KU, along with their respective affiliates, submitted an application to this Commission under FPA Section 203 for authority to merge. LG&E and KU demonstrated, pursuant to the Commission's Merger Policy Statement guidelines, that their merger would have no material adverse impact on competition, rates, or regulation. The Commission agreed and authorized the merger.[21] In addressing the competition analysis submitted by LG&E and KU, the Commission noted that both companies were then participating in the development of the Midwest ISO and relied on this fact in determining that the merger would have no adverse impact on competition in the wholesale power market. Specifically, the Commission held:

> In this case, LG&E and KU have joined [the Midwest ISO] and filed for approval to transfer operational control over their transmission facilities to the Midwest ISO. We find that the proposed mitigation measures and ratepayer protection mechanisms, in conjunction with LG&E's and KU's participation in the Midwest ISO, will ensure that the merger will not adversely affect competition, rates or regulation. On this basis, we will approve the merger without further investigation.[22]

The Commission further acknowledged Applicants' right to seek to terminate their participation in the Midwest ISO development process, but advised that if they do so, the Commission "will evaluate that request in light of its impact on competition in the KU destination markets, use [its] authority under section 203(b) of the FPA to address any concerns, and order further procedures as appropriate."[23]

Following the LG&E/KU merger, Applicants were involved in two subsequent mergers. However, neither of these mergers involved operational or physical changes to the pre-existing LG&E/KU system. In response to the application for merger of Applicants' parent, LG&E Energy Corporation, with Powergen plc ("Powergen") in 2000, the Commission did not address Applicants' participation in the Midwest ISO.[24] In approving E.ON's indirect acquisition of

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21 LG&E/KU Merger Order, 82 FERC at 62,214.

22 *Id.*

23 *Id.* at 62,223.

24 *Louisville Gas & Elec. Co.*, 91 FERC ¶ 61,321 (2000).

Applicants in 2001, however, the Commission did consider Applicants' participation in the Midwest ISO. In that order, the Commission stated:

> LG&E and KU have committed to transfer operational control of their transmission systems to the Midwest ISO and will remain members of the Midwest ISO at least until the end of 2002. Furthermore, they have committed to be members of a Commission-approved RTO thereafter. Therefore, they lack the ability to exploit their transmission assets to harm competition in wholesale electricity markets.[25]

Thus, the Commission's determination that the E.ON merger would not adversely affect competition was based in part on Applicants' continued participation in the Midwest ISO through 2002 and, if not the Midwest ISO, then some other Commission-approved RTO thereafter.

C. Applicants' Participation in the Midwest ISO

Applicants were among the earliest participants in the Midwest ISO.[26] They became involved in the initiative to create the Midwest ISO shortly after the formation of the initial agreement among six Midwest transmission owners on February 12, 1996. Applicants invested substantial time and resources in the Midwest ISO formation process, which occurred over the succeeding two year period and involved regular meetings among a wide range of participants, including large and small IOUs, municipal utilities and power agencies, and rural electric cooperatives (collectively, the "Transmission Owners" or "TOs"), as well as other stakeholder groups such as environmental advocates, IPPs, power marketers, industrial customers, state commissions and consumer advocates, and Transmission Dependent Utilities ("TDUs"). Applicants are signatories to the TO Agreement.

Applicants' interests in joining the Midwest ISO were largely related to Order No. 888 and the Commission's evolving policies regarding ISOs. In addition, Applicants strove to accommodate the Commission's desire to manage more efficiently regional transmission service, as contemplated in Order No. 888 (although the Commission did not specify there a particular mechanism for the management of such service). As a related matter, it should be noted that Applicants had agreed to control by American Electric Power Corporation ("AEP") over their transmission system for reliability coordination purposes. Thus, the concept of coordination of

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[25] E.ON Merger Order, 97 FERC at 61,283.

[26] Applicants only transferred functional control of certain facilities to the Midwest ISO – *i.e.*, all transmission facilities rated 100 kV and above.

transmission operations on a regional basis was both supported and embraced by Applicants even before their participation in the Midwest ISO.

As vertically integrated utilities with very low-cost generation resources, Applicants have always been concerned about the magnitude of RTO administrative and operational costs. As originally established, the Midwest ISO performed the core functions of an ISO, as defined in Order No. 888. However, the Midwest ISO was not structured like other ISOs. Because the Midwest ISO was not previously operated as a power pool like PJM, the New York Power Pool, or the New England Power Pool, the Midwest ISO did not originally propose to administer energy markets through regional generation dispatch. Instead, the Midwest ISO initially was designed as an ISO to operate the region's transmission facilities under a single OATT and allow open access to the regional grid without customers having to pay multiple transmission rates.

This original structure reflected the regional differences that had existed in the Midwest, resulting from the fact that the Midwest ISO covered a multi-state region that included: (i) over 30 separate control areas; (ii) vertically integrated utilities; (iii) utilities that had divested generation and/or transmission; (iv) states that had implemented retail access and others which had not; (v) areas with high-cost energy and transmission constraints; and (vi) areas with low-cost energy without transmission constraints. Thus, for all these reasons, the Midwest ISO did not administer regional energy markets under its "Day 1" operations.

Subsequently, in response to Commission orders,[27] the Midwest ISO developed its "Day 2" market design, which was patterned after the energy markets operated by the New York Independent System Operator, Inc. ("New York ISO") and PJM. In its filing seeking approval of the Day 2 concept, the Midwest ISO even admitted that its Day 2 proposal was not an idea that was originally envisioned when the Midwest ISO was created in 1998. In fact, in its original transmittal letter proposing the Day 2 market structure, the Midwest ISO stated:

> As originally organized, [the Midwest ISO's] functions were limited to providing non-discriminatory open access transmission service over the transmission assets entrusted to its operational control and receiving and distributing funds for use of those assets as agent for the [Midwest ISO] Transmission Owners. The authorities and responsibilities vested in [the Midwest ISO] created a transmission organization compliant with the requirements of

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[27] *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 97 FERC ¶ 61,326 at 62,514 (2001); *Midwest Indep. Transmission Sys. Operator, Inc.*, 98 FERC ¶ 61,075 at 61,222 (2002) ("we conditioned our approval of Midwest ISO's RTO status, in part, on its commitment to develop a superseding congestion management methodology based on market mechanisms consistent with Order No. 2000 and the final rule in our current rulemaking on RTO formation").

> Order No. 888. *It was not, however, contemplated that [the Midwest ISO] would establish or operate an energy market*. Instead, to the extent that transmission service required energy-related ancillary services, [the Midwest ISO] would either acquire such services on behalf of Transmission Customers or facilitate the direct acquisition of such services by the Transmission Customer from the energy provider.[28]

At the time of the Midwest ISO's filing of its Open Access Transmission and Energy Markets Tariff ("TEMT") in early 2004, Applicants expressed concerns about the scope and cost of the Midwest ISO's Day 2 market implementation efforts, the ultimate impact of those costs on retail ratepayers, and the shifting of regulatory oversight of Applicants' native load transactions and rate base generation facilities from the KPSC to FERC.[29] Nevertheless, in an August 6, 2004 order, the Commission approved the TEMT over Applicants' objections.[30]

Importantly, Applicants have had occasion to give careful consideration to, and to quantify, the effects of the Day 2 markets in the course of a KPSC investigation into Applicants' continued membership in the Midwest ISO. As discussed below, this careful consideration has led Applicants to conclude that their and their customers' best interests are no longer served by continued participation in the Midwest ISO.

While Applicants have repeatedly and consistently expressed concerns about costs associated with Midwest ISO membership and the ultimate impact of these costs on retail rates, they nevertheless have worked for years to resolve these concerns through the Midwest ISO stakeholder process and at the Commission. In its *SMD White Paper*, the Commission indicated that it may be willing to allow different RTO configurations and provide the industry with more

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28 *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER02-2595-000, Sep. 24, 2002, Transmittal Letter at 2 (footnotes omitted) (emphasis added).

29 *See generally* Motion to Intervene, Comments and Request for Summary Disposition or Conditions of LG&E Energy LLC, *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER04-691-000 (May 7, 2004); Request for Rehearing of LG&E Energy LLC, *Midwest Indep. Transmission Sys. Operator, Inc.*, Docket No. ER04-691-000 (Sep. 7, 2004).

30 *Midwest Indep. Transmission Sys. Operator, Inc.*, 108 FERC ¶ 61,163 (2004).

flexibility to comply with its broad federal policy goals.[31] Shortly after the Commission issued this white paper, Applicants began to seriously consider withdrawing from the Midwest ISO.[32]

Specifically, Applicants began planning for the establishment of an alternative framework – one which would be: (i) cost-effective; (ii) achieve the Commission's goals regarding non-discriminatory, open access transmission service and facilitation of regional reliability coordination; and (iii) satisfy Kentucky's goals of providing the lowest cost and most reliable electric service to Kentucky ratepayers. In addition, such an alternative would have to address the Commission's concerns about Applicants' previous mergers and the impact of those mergers on competition. On December 28, 2004, Applicants gave the Midwest ISO written notice of their intention to withdraw their membership.[33]

D. Kentucky Proceedings to Investigate Applicants' Continued Membership in the Midwest ISO

When Applicants originally joined the Midwest ISO, the KPSC was very supportive of Applicants' participation. For example, in approving the Powergen merger in 2000, the KPSC encouraged Applicants' continued participation in the Midwest ISO, stating:

> Historically, LG&E and KU have actively participated in organizations such as the East Central Area Reliability Council and [the Midwest ISO] which help to ensure the reliability of the bulk power system and which, in turn, have a significant impact on retail electric service. The Commission encourages LG&E and KU to continue active participation in these organizations,

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31 *Wholesale Power Market Platform*, Apr. 28, 2003 <http://www.ferc.gov/industries/electric/indus-act/smd/white_paper.pdf>.

32 Applicants have considered withdrawing from the Midwest ISO in the past. On January 4, 2001, they filed with the Commission a notice of withdrawal and request for authority to withdraw from the Midwest ISO, citing concerns about the Midwest ISO's ability, in light of the withdrawals by several other members, to comply with the "scope and configuration" requirements of Order No. 2000. *See Louisville Gas & Elec. Co. and Kentucky Utilities Co.*, Notice of Withdrawal of Louisville Gas and Electric Company and Kentucky Utilities Company from the Midwest ISO, Docket No. ER01-899-000, Jan. 4, 2001. However, this matter was resolved by settlement among the withdrawing and remaining members of the Midwest ISO – a settlement that satisfactorily resolved Applicants' concerns. *See Illinois Power Co.*, 95 FERC ¶ 61,183 (2001).

33 The December 28, 2004 Notice of Withdrawal is attached hereto as Exhibit H.

> *particularly with respect to maintaining the reliability of the electricity supplied to their customers.*[34]

The KPSC went so far as to require Applicants to accept the following as an express condition to KPSC's approval of the merger: "Powergen commits that its present expectation is for LG&E and KU to remain members of the Midwest ISO."[35] Similar statements acknowledging and encouraging continued Midwest ISO participation were included in the KPSC's E.ON merger approval order.[36]

Notwithstanding this historical support for Applicants' Midwest ISO participation, on July 17, 2003, the KPSC initiated an investigation of Applicants' membership in the Midwest ISO.[37] Specifically, since Kentucky does not allow retail customer choice, unlike certain other Midwest ISO-participating states, the KPSC directed an investigation into "the extent to which LG&E and KU, as providers of bundled retail electricity, utilize and receive benefits from the service provided by the Midwest ISO, and whether those benefits are commensurate with costs."[38] The KPSC also directed an investigation into the Midwest ISO's intent to expand its role beyond its original scope – *i.e.*, to "new matters, such as resource adequacy and demand response programs."[39] Most importantly, it was in this order that the KPSC first indicated its willingness to explore the feasibility of Applicants leaving the Midwest ISO and joining a different, "southern" RTO that had participants from states more similarly situated to Applicants in terms of their vertical integration and bundled retail service orientation.[40]

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34 *Joint Application of Powergen plc, LG&E Energy Corp., Louisville Gas and Electric Company and Kentucky Utilities Company for Approval of Merger*, KPSC Case No. 2000-095, Order issued May 15, 2000, at 22-23 (emphasis added).

35 *Id.*, Appx. A, Other Commitments and Assurances No. 15.

36 *See Joint Application for the Transfer of Louisville Gas and Electric Company and Kentucky Utilities Company in Accordance with E.ON AG's Planned Acquisition of Powergen plc*, KPSC Case No. 2001-104, Order issued August 6, 2001, Appx. A, Other Commitments and Assurances No. 49.

37 *Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc*., KPSC Case No. 2003-266, Order issued July 17, 2003.

38 *Id.* at 2.

39 *Id.* at 3.

40 *Id.*

Applicants responded to the KPSC's inquiries by submitting substantial amounts of company and expert evidence. With respect to the cost/benefit question, Applicants retained an independent economic consultant, Dr. Mathew J. Morey, Senior Consultant, Laurits R. Christensen Associates, Inc., to conduct a study of the relative costs and benefits of the various RTO and non-RTO options that the KPSC found were available to Applicants. This independent economic analysis showed that, on the basis of the available quantitative evidence as well as Dr. Morey's qualitative assessment of hard-to-quantify factors, a "stand-alone" option, *i.e.*, withdrawing from RTO participation altogether and recommencing their own independent operation of their transmission systems under a Commission-approved OATT, was economically superior to any of the RTO options. Dr. Morey concluded that, even with the payment of an exit fee, Applicants would still realize a net benefit from Midwest ISO withdrawal. Significantly, Dr. Morey also posited that none of the alternative RTOs he studied could offer a more favorable cost/benefit outcome for Applicants than the stand-alone alternative.

After the Midwest ISO submitted testimony to rebut Applicants' cost-benefit study results, the KPSC held hearings on February 25-27 and April 8, 2004. Thereafter, the evidentiary record was closed. On March 31, 2004, the Midwest ISO filed its TEMT and Day 2 markets proposal with the Commission. Because of concerns about the impact of Day 2 operations on Applicants and on Kentucky ratepayers, the KPSC issued an order on June 22, 2004, that reopened its investigation and requested that Applicants submit further testimony addressing the Midwest ISO's Day 2 market proposal and its potential impacts, as well as the relative costs and benefits of pursuing alternative RTO and non-RTO options.[41] Following the actual implementation of Day 2 operations, the KPSC found it necessary to investigate further Applicants' Midwest ISO membership (which was initially intended to address this Commission's concern over the mergers and any potential adverse impact on competition) and any adverse impact on Kentucky retail rates and KPSC regulation. In August 2005, the KPSC expressed concern regarding ratepayer protection and shifts in regulatory authority as reasons for their investigation of Day 2 operations.[42]

Applicants submitted written testimony in the reopened investigation proceeding in September 2004 and January, April, and July 2005. The Midwest ISO submitted written

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[41] *Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, KPSC Case No. 2003-266, Order issued June 22, 2004.

[42] In August 2005, the KPSC stated "[t]he list of issues spawned by the creation of RTOs is growing and the Commission is seemingly faced with ever decreasing authority as FERC addresses new issues regarding RTOs and transmission. Recognizing that RTOs are predominantly federally driven, we are unsure as to how Kentucky's energy policy can incorporate plans to address this issue." *Kentucky's Electric Infrastructure: Present and Future: Assessment Conducted Pursuant to Executive Order 2005-121 by the Kentucky Public Service Commission,* Aug. 22, 2005, at 56 <http://psc.ky.gov/agencies/psc /hot_list/ElectricRpt_082205/MainRpt/electric1_CompleteRpt.pdf>.

testimony in the same proceeding in September and November 2004, as well as January, February, March and July 2005. The KPSC held evidentiary hearings on July 20-21, 2005. This proceeding is still pending at the KPSC.

In their submitted testimony, Applicants undertook a reexamination of the costs and benefits of their Midwest ISO participation, in light of the implementation of Day 2 operations. Applicants directed their independent economic consultant, Dr. Morey, to undertake a supplemental study and requested that the new study examine the relative costs and benefits of: (i) staying in the Midwest ISO with Day 2 market implementation; (ii) joining PJM; (iii) joining SPP; and (iv) withdrawing from further RTO participation and, instead, operating their own transmission system, but with an independent Reliability Coordinator (referred to in the KPSC proceeding record as the "Transmission Operator With Reliability Coordinator" or "TORC" alternative). Dr. Morey's supplemental study mirrored the results of the first study. Specifically, among other findings, Dr. Morey concluded that, based on the same study timeframe of six years (through 2010), the TORC remains the most economically superior option.

In light of all relevant factors, Applicants advised the KPSC that they would begin seeking withdrawal from the Midwest ISO and would pursue an alternative model that satisfies the Commission's non-discriminatory, open access transmission service objectives and other relevant policy goals. In order to achieve these objectives, Applicants have expressly asked the KPSC to find that: (i) Applicants' continued Midwest ISO membership is not in the public interest because of the existence of lower cost alternatives; (ii) Applicants may continue pursuing this Commission's approval to exit the Midwest ISO, and may pursue an alternative to Midwest ISO membership that is acceptable to both this Commission and the KPSC; and (iii) Applicants may establish a regulatory asset for the amount of any exit fee that must be paid to the Midwest ISO pursuant to Article Five of the TO Agreement.

IV. APPROVALS UNDER SECTION 205 OF THE FEDERAL POWER ACT

In this section Applicants request that the Commission accept certain rates for filing as follows.

In <u>Section A</u>, Applicants request authority to withdraw from the TO Agreement and explain why such a withdrawal is just and reasonable.

In <u>Section B</u>, Applicants request that the Commission accept for filing a revised *pro forma* OATT (which has been modified to implement the Rate De-Pancaking Maintenance Plan as well as the functions of the ITO and Reliability Coordinator). The OATT also includes *pro forma* agreements between Applicants and the ITO and Reliability Coordinator. Applicants request that the Commission accept for filing the OATT, including the *pro forma* Agreements.

In Section C, Applicants discuss the impact of this filing on their pending requests for authority to sell power and energy at market based rates.

A. Withdrawal From the Midwest ISO TO Agreement is Just and Reasonable.

Applicants request that the Commission approve their withdrawal from the TO Agreement. Such withdrawal constitutes a change in rates under FPA Section 205. Applicants request that the Commission accept this change in rates for filing, effective 30 days after Commission approval, without suspension or hearing. As demonstrated below: (i) Applicants are not contractually barred from withdrawal from the Midwest ISO; (ii) the ITO/Reliability Coordinator proposal involves less costs; (iii) existing transmission customers will be protected under a De-Pancaking Maintenance Plan including GFA customers; and (iv) the Midwest ISO and its members will not be harmed by Applicants' withdrawal.

1. TO Agreement

Applicants have complied with the terms of the TO Agreement and are not contractually barred from withdrawing from the Midwest ISO.

The TO Agreement specifically provides that transmission-owning members of the Midwest ISO may withdraw their facilities from the Midwest ISO's transmission system.[43] In 1998, when the Commission accepted the TO Agreement, the Commission stated that it would permit withdrawals from the Midwest ISO pursuant to the withdrawal process contained within Article Five of the TO Agreement.[44] The Commission also required that the TO Agreement be revised to clarify that any notice of withdrawal from the Midwest ISO must be filed with the Commission and may become effective only upon the Commission's approval.[45]

Under Article Five of the TO Agreement, transmission-owning members of the Midwest ISO may commence the withdrawal process by submitting a written notice of withdrawal to the Midwest ISO President. Under this provision, the withdrawal may not take effect before December 31 of the calendar year following the calendar year in which the notice is given. In relevant part, Article Five states:

> A Member who is also an Owner may, upon submission of a written notice of withdrawal to the President, commence a process

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43 *See* TO Agreement, Art. Two, § X.D, Original Sheet No. 59.

44 *Midwest Indep. Transmission Sys. Operator, Inc.*, 84 FERC ¶ 61,231 at 62,151 (1998).

45 *Id.*

> of withdrawal of its facilities from the Transmission System. Such withdrawal shall not be effective until December 31 of the calendar year following the calendar year in which notice is given.[46]

On December 28, 2004, Applicants provided a notice of withdrawal to the Midwest ISO in compliance with the aforementioned provision of the TO Agreement. Therefore, the earliest date that such withdrawal could take effect would be December 31, 2005. In compliance with the Commission's directive that withdrawing members file their notices of withdrawal for Commission approval, Applicants have attached a copy of their December 28, 2004 notice of withdrawal as Exhibit H.

Applicants have entered into negotiations with Midwest ISO regarding the financial and practical issues associated with their withdrawal. Applicants believe that they and the Midwest ISO are close to finalizing a withdrawal agreement which will include an exit fee amount to be paid by Applicants, and a transition plan for transferring operations to the Reliability Coordinator and the ITO. To date, Applicants and the Midwest ISO have made significant progress in negotiating the terms of the withdrawal. For example, Applicants and the Midwest ISO have already reached agreement on key parts of a methodology for calculating the Midwest ISO exit fee and a process for developing a transition plan.[47] Applicants will amend this filing when any agreement or arrangement with Midwest ISO is finalized.

2. Reduced Costs

The Commission should accept for filing Applicants' request to withdraw from the TO Agreement. Withdrawal is reasonable because continued Midwest ISO membership will mean higher costs for Applicants' native load customers. This fact is supported in the testimony of Dr. Morey (Exhibit C hereto). Among other things, Dr. Morey finds that Applicants' proposal is a reasonable means to fulfilling Order No. 888 objectives because the benefits of membership in an RTO such as Midwest ISO – lower power procurement costs and increased off-system sales and margins – are, given the Companies' existing low cost generation portfolio and history of self supply, small compared to the costs of membership.[48] Dr. Morey also finds that Applicants'

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46 TO Agreement, Art. Five, § I, Original Sheet No. 75.

47 On October 6, 2005, Applicants sent a letter to Stephen Kozey, Vice President and General Counsel of the Midwest ISO, summarizing the status of negotiations between Applicants and the Midwest ISO. This letter memorializes several agreements in principle between Applicants and the Midwest ISO with regard to a methodology for calculating the Midwest ISO exit fee and a process for developing a transition plan. This letter is attached as Exhibit N.

48 Morey Testimony at 3.

proposal satisfies Order No. 888 requirements at lower cost than does RTO membership.[49] In particular, Dr. Morey compares the costs of the ITO/Reliability Coordinator proposal with the costs currently incurred by Applicants as members of the Midwest ISO and concludes that Applicants could save between $8 million and $13 million per year.[50]

In order to meet the non-discriminatory, open access requirements of Order Nos. 888, 889, and 2000, Applicants must either remain members of the Midwest ISO or employ another option for satisfying the Commission's open access and regional reliability objectives, as manifested by the Merger Conditions of the LG&E/KU and E.ON mergers. From a cost perspective, Applicants' ITO/Reliability Coordinator proposal closely resembles the "stand-alone" option studied in the KPSC proceeding, but has the added benefits of maintaining the open access and reliability *status quo* for customers in the LG&E/KU and Midwest ISO service areas and ensuring a heightened level of independent tariff administration, transmission planning, and regional reliability coordination. Specifically, Applicants' ITO/Reliability Coordinator proposal meets the objectives of Order Nos. 888, 889 and 2000 by: (i) transferring key transmission-related functions to third parties; (ii) resolving seams issues and eliminating rate pancaking (as discussed below); and (iii) ensuring non-discriminatory, open access transmission service.

3. Customers Are Protected

Applicants' proposal will not adversely impact existing transmission customers. Applicants intend to abide by their obligation in Article Five of the TO Agreement, which provides that withdrawing Midwest ISO members are bound to hold existing customers harmless from any changes in rates, terms, or conditions of existing transmission service.

In this regard, Section II.A of Article Five provides:

> Users taking service which involves the withdrawing Owner and which involves transmission contracts executed before the Owner provided notice of its withdrawal shall continue to receive the same service for the remaining term of the contract at the same rates, terms, and conditions that would have been applicable if there were no withdrawal. The withdrawing Owner shall agree to continue providing service to such Users and shall receive no more in revenues for that service than if there had been no withdrawal by such Owner.

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49 *Id.* at 3, 20.

50 *Id.*

Applicants propose to meet this contractual obligation through the plan outlined below. In addition, Applicants propose to use the same formula rate for transmission service contained in Attachment O of the Midwest ISO OATT. Accordingly, there will be no transmission rate level impact on customers.

a. De-Pancaking Maintenance Plan

Applicants seek to ensure that their withdrawal from the Midwest ISO and their institution of an ITO and a Reliability Coordinator is consistent with the Commission's goal of eliminating transmission rate pancaking. Applicants are also cognizant of the fact that their withdrawal from the Midwest ISO must be consistent with their merger commitments, as explained in detail in Section V below. Accordingly, Applicants propose a Rate De-Pancaking Maintenance Plan ("RDMP"), in order to ensure that customers continue to enjoy the same de-pancaked rates which currently are in effect between Applicants' zone, the Midwest ISO, and PJM. Applicants propose to preserve the *status quo* regarding pancake elimination by implementing a system that mirrors the de-pancaked transmission protocols of the Midwest ISO and PJM. Through this commitment, Applicants seek to ensure that there are as few economic seams between their system and Midwest ISO/PJM as possible.

In this regard, Applicants will provide point-to-point ("PTP") transmission on their system on a "drive through," "drive in" or "drive out" basis – for service between Applicants' system and points within the existing Midwest ISO and PJM systems, as well as through Applicants' system – on a comparable basis, without the imposition of pancaked base transmission rates for virtually all wheels. Applicants propose several exceptions to this generally applicable rate mechanism which are intended to avoid gaming, as noted below. Applicants will also provide and facilitate network service between points of receipt and points of delivery on the Transmission System and on the Midwest ISO and PJM systems. Applicants refer to such point-to-point and network service provided under the RDMP as "Reciprocity Firm."[51]

Applicants propose that existing transmission arrangements – both existing Midwest ISO Tariff transmission contracts and GFAs – will enjoy the same service and pricing that such customers receive today. This fact will be true for service which "traverses" Applicants' system and the Midwest ISO/PJM, as well as network and point-to-point arrangements "within"

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[51] For new Reciprocity Firm service initiated after the effective date of the proposed rates, Applicants reserve the right to charge the costs of expansion (where applicable) and losses, in accordance with the OATT. Where applicable, customers would bear the costs of expansion, even if base transmission charges would be waived for such a Reciprocity Firm transaction. Applicants believe such expansion charges, where applicable, are reasonable. It would be inequitable, for example, to ask network customers to bear expansion costs, while at the same time providing Reciprocity Firm customers point to point service for free.

Applicants' transmission system. For new service (*i.e.*, contracts entered into after the effective date of Applicants' withdrawal from the Midwest ISO), Applicants propose the same de-pancaked service under the RDMP as would be effective today with the exceptions noted below. Applicants' new OATT submitted with this filing reflects the RDMP proposal described above.

Importantly, Applicants will provide Reciprocity Firm service subject to the Midwest ISO and PJM agreeing that Applicants will receive comparable treatment under the Midwest ISO and PJM tariffs for sales into, through and out of the Midwest ISO and PJM, respectively. In Applicants' discussions with the Midwest ISO, the Midwest ISO has not objected to continuing the de-pancaked rate protocol. As with the current pricing protocols in the Midwest ISO and PJM, Applicants will charge customers for transactions that sink in the Applicants' system or are transmitted wholly "within" Applicants' system. Finally, Applicants also propose to maintain the *status quo* regarding transmission service which Applicants provide to themselves for their native load. Under the Midwest ISO's TEMT, as transmission owners and network service customers (in essence, customers "of themselves"), Applicants are not billed for network service to their native load.[52] After withdrawing from the Midwest ISO, Applicants will similarly not bill themselves for these services.[53]

Under the RDMP, rate pancaking will be eliminated to the same extent and over the same territory as is the case today, with one exception. Applicants propose to charge their applicable PTP rate for transactions that: (i) source within or outside of the Super Region;[54] (ii) sink outside of the Super Region; and (iii) require (x) a withdrawal point scheduled at an interconnection between Applicants and a non-Super Region system (*e.g.*, sink TVA, or sink Duke) or (y) require transmission service through Applicants' control area. Applicants' charging of a PTP rate for these transactions is reasonable because, if Applicants were to remain in Midwest ISO, the Midwest ISO "through and out" rate would be charged for such transactions. Applicants believe that if their PTP rate is not charged for such transactions, the elimination of an "out" charge at Applicants' buses with interconnected utilities (*e.g.*, TVA, Duke) could significantly increase the possibility of gaming.[55]

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[52] MISO TEMT § 37.3, Second Revised Sheet No. 342.

[53] *See* LG&E/KU OATT § 32.6.

[54] "Super Region" is defined as the Midwest ISO/PJM footprint.

[55] Alternatively, if the Commission does not believe that such charges are appropriate, Applicants would be willing to charge the Midwest ISO out rate at its bus with non-Super Region control areas as long as Applicants receive their appropriate share of revenues from such service.

Applicants respectfully request that the Commission approve the RDMP so that customers in Kentucky and throughout the Midwest ISO and PJM can continue to receive transmission service without the re-introduction of pancaked rates.

Tables are included in the Applicants' proposed OATT Schedules 7 and 8 that set forth the applicable base transmission charges under the RDMP for various PTP transaction scenarios. As demonstrated in these tables, the RDMP generally maintains the *status quo* regarding pancaked rates. Where paths have been de-pancaked, they will generally remain so to the greatest extent possible. Where paths remain subject to pancaked charges, they will continue to pay pancaked charges. Applicants note that the New York ISO and ISO New England recently eliminated rate pancaking through a similar voluntary arrangement.[56] Applicants believe the same type of voluntary arrangement is appropriate and reasonable here.[57]

b. Curtailment

Reciprocity between LMP markets like Midwest ISO/PJM and Applicants' system could create issues regarding curtailment priorities. Thus, Applicants propose a curtailment priority as follows (in order from highest to lowest priority):

1. Native load customers, all network and intra-zonal PTP;
2. Reciprocity Firm point-to-point customers; and
3. Non-firm customers.

Order Nos. 888 and 888-A require *pro rata* curtailments of network and native load and firm point-to-point customers together.[58] However, there are specific exceptions to the general rule on *pro rata* curtailment.[59] In particular, the Commission has stated that firm point-to-point

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56 *ISO New England, Inc*., 109 FERC ¶ 61,147 (2004), *on reh'g*, 110 FERC ¶ 61,111 (2005).

57 While pancaked rates have been eliminated, the transitional rate mechanism known as the Seams Elimination Cost/Charge Assignment/Adjustment ("SECA") is currently being litigated in Docket Nos. ER05-6-001, *et al*. These proceedings involve monthly charges on load through March 2006. Thus, the SECA will no longer be in place upon Applicants' projected withdrawal date from the Midwest ISO, *i.e.*, spring of 2006, before the start of the summer cooling season.

58 *See* Order No. 888 at 31,748-50; Order No. 888-A at 30,278-81.

59 Section 1233 of the Energy Policy Act of 2005 amended the FPA to provide that load serving entities are entitled to use their transmission rights to the extent required to meet their service obligations. *See* FPA Section 217 [16 U.S.C. § 824q (2005)]; *see also Northern States Power Co. v. FERC*, 176 F.3d 1090 (8th Cir. 1999) (Commission could not require curtailment of native load on comparable basis to wholesale customers when facing

customers should receive an appropriate rate adjustment where their curtailment priority is different than network service customers.[60] Applicants propose to charge Reciprocity Firm customers a zero transmission rate. Thus, these firm transmission customers already receive the best possible rate, and therefore, it is reasonable to queue transaction curtailments as proposed by Applicants.

c. Grandfathered Contracts

Parties to grandfathered agreements ("GFAs") involving Applicants will not be adversely affected by Applicants' withdrawal from the Midwest ISO. In fact, in several circumstances, such parties should see rate reductions. Applicants are parties to several GFAs, listed at Attachment P to the Midwest ISO's TEMT.[61] These GFAs can be divided into six categories:

(i) Contracts that have expired or will expire by the time Applicants' proposed exit from the Midwest ISO would be effective;

(ii) Contracts that were "carved out" from the Midwest ISO markets;

(iii) Contracts where the customer is not LG&E Energy Marketing, Inc. ("LEM") and the party chose to take service under "Option A" of the Midwest ISO's TEMT;

(iv) Contracts where the customer is not LEM and the party chose to take service under "Option B" of the Midwest ISO's TEMT;

(v) Contracts where the transmission customer taking service is LEM; and

(vi) Contracts where the party taking service is TVA.

As noted below, these customers will receive service at a comparable level after the Applicants' withdrawal from the Midwest ISO as those customers receive today, or will otherwise be unaffected by Applicants' withdrawal.

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constraints); *Northern States Power Co.*, 89 FERC ¶ 61,178 (1999) (Commission order on remand recognizing court order).

60 *Northern States Power Co.*, 89 FERC ¶ 61,178 at 61,551, 61,553 (1999).

61 Relevant portions of Attachment P are appended hereto as Exhibit M.

i. Expiring GFAs

GFA 215(b) expired on May 31, 2005, and GFA 221 is scheduled to expire in January 2006. This expiration is prior to the time when Applicants project they will exit the Midwest ISO and implement their ITO/Reliability Coordinator proposal.

ii. Carved-Out GFAs

With respect to "carved out" contracts (GFAs 220 and 222), customers under these contracts have continued to receive service pursuant to the terms of those GFAs and are unaffected by the Midwest ISO markets. Indeed, the purpose of carved-out service is to insulate customers from receiving the benefits or burdens of transmission service under the Midwest ISO's TEMT. Thus, customers taking service under these GFAs will simply continue to receive service according to the terms of those GFAs and will be unaffected by Applicants' withdrawal from the Midwest ISO. Importantly, customers taking carved out GFA service under the Midwest ISO's TEMT are now subject to a share of the Midwest ISO's Schedule 10, 17 and 18 charges.[62] After Applicants' withdrawal from the Midwest ISO, these charges will no longer be applicable, resulting in a significant cost savings to these customers.

iii. Option A

There is only one GFA – GFA 215(a) – for which a non-LG&E/KU-affiliated customer chose to take Option A service. This is a contract between LG&E and Eastern Kentucky Power Cooperative ("EKPC"). This GFA is scheduled to expire in September 2006. Under Option A, the GFA Responsible Entity receives an allocation of FTRs in accordance with nominated capacity and is responsible for congestion and losses. LG&E is the GFA Responsible Entity and provides service to EKPC under the terms of the contract. Since Applicants project their Midwest ISO withdrawal to be effective in the Spring of 2006, there will be an approximately six-month period prior between Applicants' withdrawal from the Midwest ISO and when this contract will expires. During that period, LG&E will continue to provide service to EKPC under the terms of the contract, just as EKPC receives service today. EKPC will not face any degradation of service, nor will EKPC face any increase in costs. The Option A provisions impact LG&E's costs, not EKPC's. Thus, EKPC should see no difference in service or costs.

iv. Option B

There is only one GFA – GFA 214, between LG&E and Indiana Municipal Power Agency ("IMPA") – for which a non-LG&E/KU affiliated customer chose to take Option B service. Under this GFA, IMPA takes service into PJM for a specific, contracted-for generation

[62] Midwest ISO TEMT § 38.8.4.6, Substitute First Revised Sheet No. 454B.

resource to serve specified load. The Option B service does not provide for an allocation of FTRs and does not impose congestion and losses charges. Under the RDMP, IMPA will not face pancaked charges for access to PJM. Moreover, just as LG&E provides service to IMPA according to the terms of the contract, and IMPA is not at risk for congestion and losses today, IMPA will not be at risk for congestion or losses in the future. LG&E will simply continue to provide service under the terms of the contract after Applicants' withdrawal from the Midwest ISO.

v. Contracts in Which LEM is the Customer

For GFAs 216, 222, 223, 224, 418, 419, and 420, LEM is the transmission customer and will continue to take service on the Transmission System according to the terms of the GFAs. Under these agreements, Applicants are obligated to deliver electricity to a customer. If Applicants fail to perform under these GFAs, they will be liable for failure to perform. However, as noted throughout this section, there will be no change in transmission delivery service that will affect any such customer's continued receipt of electricity pursuant to the contracts at issue.

vi. TVA Contracts

This final category consists of two contracts – GFAs 219 and 225. GFA 219 involves TVA taking service under Option A. Just as is the case with the EKPC contract under Option A, LG&E will continue to provide service to TVA under the terms of the contract just as EKPC receives service today. TVA will not face any degradation of service, nor will TVA face any increase in costs. The Option A provisions impact LG&E's costs, not TVA's. Thus, TVA should see no difference in service or costs. With respect to GFA 225, this three-party agreement between TVA, Cinergy, and LG&E allows TVA to access the Midwest ISO (specifically, Cinergy). TVA will continue to receive service under the terms of the contract, and under the RDMP, TVA should receive non-pancaked service into Cinergy in any event (to the extent TVA requires service above and beyond service provided for under the contract).

d. Existing Midwest ISO Tariff Contracts

Applicants will continue to honor existing Midwest ISO short and long term transmission contracts which require service within Applicants' system.[63] In addition, with respect to transmission contracts under the Midwest ISO Tariff that involve Applicants' system but have sources or sinks in other zones, Applicants will not re-impose any pancake charges under the RDMP. For instance, Illinois Municipal Electric Association ("IMEA"), East Kentucky Power Cooperative, and Hoosier Energy are parties to Midwest ISO transmission contracts under which

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[63] Long term existing Midwest ISO transmission contracts are listed on Attachment E to the OATT.

these customers take service with either points of receipt or points of delivery in Applicants' zone, and points of receipt or points of delivery in another Midwest ISO zone. For contracts such as these, where customers take service under the Midwest ISO TEMT involving Applicant's zone, Applicants propose that such customers continue to be customers of the Midwest ISO, with Applicants ensuring that such customers continue to enjoy the same service they have today. This treatment is consistent with Applicants' obligation under the Midwest ISO TO Agreement.[64]

As noted above, Applicants will continue to honor existing Midwest ISO transmission contracts. Applicants will require, however, that such customers sign a transmission service agreement for the portion of service which such customers take over Applicants' system. This will ensure that Applicants are protected with appropriate commercial terms. Otherwise, such customers would take service over Applicants' system without any contractual relationship to Applicants.

e. Other Seams Issues

As described more fully below, Applicants choice of TVA as the Reliability Coordinator will ensure that no new seams are created when Applicants withdraw from the Midwest ISO. TVA currently has reliability coordination operations in Kentucky and acts as reliability coordinator for East Kentucky Power Cooperative and Big Rivers Electric Cooperative. Accordingly, this filing seeks to put more load under TVA, but management of the seams should not change. Indeed, seams issues will be unaffected by Applicants' withdrawal from the Midwest ISO, in large measure because of TVA's Joint Reliability Coordination Agreement with the Midwest ISO and PJM ("JRCA"), and the JRCA's corresponding Congestion Management Process ("CMP"). These seams agreements are discussed below.

i. Joint Reliability Coordination Agreement

Beginning in May 2004, the Midwest ISO, PJM, and TVA (the "JRCA Parties") began exchanging certain data and information in order to facilitate inter-regional coordination, system reliability, and efficient market operations for the Midwest ISO and PJM. In April 2005, the JRCA Parties executed the JRCA in order to establish other reliability protocols, including the pre-existing data exchange. The JRCA provides for data flow between TVA and the Midwest ISO and PJM, and congestion management on flowgates affected by flows of TVA and either the Midwest ISO or PJM, or flowgates of any JRCA Party and a Third Party that executes a Reciprocal Coordination Agreement. The JRCA also outlines system coordination among the Parties, including coordination of scheduled outages, emergency operations, transmission expansion planning, and reactive power coordination. The JRCA is attached hereto as Exhibit L.

64 *See generally* Midwest ISO TEMT § 38.8, Substitute Second Revised Sheet No. 442.

ii. Congestion Management Process

The CMP is a separate document from the JRCA, but is incorporated into the JRCA by reference.[65] The CMP details the specific procedures for management of congestion on flowgates, particularly coordinated flowgates – *i.e.*, flowgates across which there are energy flows of one or more parties and one or more third parties. The CMP provides detail in the areas of: market flow calculation; firm generation-to-load flow determination; the tagging of import and export transactions; and flowgate administration. One of the primary seams issues that must be addressed is how different congestion management methods (market and non-market) will interact to ensure that parallel flows and impacts are recognized and controlled in a manner that ensures system reliability. The solutions proposed in the CMP will enhance overall transparency by utilizing existing real-time applications to monitor and react to flowgates external to an entity's footprint.

4. Impact on the Midwest ISO and its Membership

Applicants' withdrawal from the Midwest ISO will have no adverse impacts on the Midwest ISO's operations, its energy markets, or its membership.

First, the Midwest ISO is a mature RTO with widespread participation in its regional footprint. The Midwest ISO oversees more than 100,000 miles of transmission lines and more than 100,000 megawatts of electric generation over approximately 1.1 million square miles. Applicants' operations constitute a very small portion of the Midwest ISO system, with only 2,420 miles of transmission lines (100 kV and above),[66] approximately 8,000 MW of electric generation, and a service territory of approximately 7,300 square miles.

Applicants' system represents a mere "drop in the bucket" compared to the Midwest ISO regional system and, therefore, Applicants' withdrawal from the Midwest ISO only increases market concentration slightly.[67] The Midwest ISO's total generation is approximately 115,000 MW (after accounting for outages) and LG&E's generation in the Midwest ISO is only approximately 7,500 MW (after outages). According to Dr. Hieronymus' analysis, the Midwest ISO's Herfindahl-Hirschman Index ("HHI") will only modestly increase under most

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[65] The CMP is a rate schedule for both the Midwest ISO and PJM. *See* Midwest ISO FERC Electric Tariff, Rate Schedule No. 5; PJM Interconnection L.L.C., FERC Electric Tariff, Rate Schedule No. 38.

[66] *See supra* n. 26.

[67] *See* Hieronymus Testimony (Exhibit D hereto) at 8. Dr. Hieronymus' workpapers are included on the two enclosed CD-ROMs.

circumstances as a result of Applicants' withdrawal and, for the most part, will remain unconcentrated.[68]

Second, Applicants' location within the Midwest ISO highlights the minimum impact that withdrawal will have on the Midwest ISO. Applicants reside on the "border" of the Midwest ISO footprint and are, therefore, not essential for the Midwest ISO's connectivity needs. In other words, Applicants' withdrawal will not involve anomalous connectivity and seams issues. Further, after withdrawal, Applicants will continue to have interconnected operations with the Midwest ISO, and commerce between the Midwest ISO's and Applicants' regions will continue. Applicants also have interconnection agreements with all neighboring utilities on file with the Commission.

Third, the Midwest ISO enjoys widespread participation across a 15-state footprint. Members of the Midwest ISO include investor-owned utilities, cooperatives, municipals, public power districts, independent transmission-only companies, power marketers, independent power producers and industrial end users. Also, the Midwest ISO appears to have the support of most of the state commissions within its footprint.[69] Given this widespread support, Applicants believe that their withdrawal will not create an adverse impact on the Midwest ISO and its status as an RTO. In fact, as Dr. Ronald McNamara, Vice President of Market Management for the Midwest ISO, testified before the KPSC, the Midwest ISO is not concerned that Applicants' withdrawal will lead to other Midwest ISO members withdrawing as well.[70]

Fourth, the Midwest ISO is not the nascent organization it was when entities sought approval to leave the Midwest ISO and join the Alliance RTO in 2001.[71] The Midwest ISO has not only undertaken all Day 1 operational testing and addressed all start-up concerns, but also has begun Day 2 market operations. Applicants believe that their participation is not critical to the operational integrity of the Midwest ISO grid or its markets, as was arguably the case when other entities sought to leave the Midwest ISO in 2001.

Finally, Dr. McNamara testified before the KPSC that Applicants' withdrawal is a "business decision" for the companies.[72] Indeed, Dr. McNamara specifically stated that neither

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68 *Id.*

69 *See, e.g.*, Craig S. Cano, *MISO success seen as "proof positive" of value offered by regional state committee*, INSIDE F.E.R.C., Aug. 15, 2005, at 1 (describing Organization of MISO States' support for MISO's Day 2 markets).

70 KPSC Case No. 2003-00266, Transcript of Evidence (Volume I) at 31:5-21 (July 20, 2005).

71 *See Illinois Power Co.*, 95 FERC ¶ 61,183 (2001).

72 *See* KPSC Case No. 2003-00266, Transcript of Evidence (Volume I) at 22:6-19 (July 20, 2005).

the Midwest ISO nor any stakeholder should stand in the way of Applicants' business decision to withdraw from the Midwest ISO.[73] Further, in the context of the KPSC investigation discussed above, the Midwest ISO never testified that Applicants' withdrawal would harm the Midwest ISO. Midwest ISO's testimony only went to the issue of trying to prove that the benefits of Midwest ISO membership outweigh the costs. In fact, on August 25, 2004, James P. Torgerson, President and CEO of the Midwest ISO, was quoted as saying that Applicants' withdrawal from the Midwest ISO would have only a "minor impact" on the Day 2 markets.[74] Later, Dr. McNamara testified in the KPSC proceeding that Applicants' withdrawal would not have a material financial impact on the Midwest ISO and agreed with Mr. Torgerson's August 25, 2004 statement.[75] It is also significant that other Midwest ISO members and stakeholders did not participate in the KPSC proceeding.[76]

5. Consistency with Commission Policy and Precedent

Applicants' proposal to withdraw from the Midwest ISO is consistent with Commission policy. In Order No. 2000, the Commission embraced the creation of third-party regional transmission entities that could independently administer and operate transmission systems, but specifically rejected the idea of mandatory RTO membership. To this end, the Commission adopted a flexible approach under which utilities could voluntarily seek to join RTOs or other regional entities. The Commission stated that "[g]iven the rapidly evolving state of the electric industry, we want to allow involved participants the flexibility to develop mutually agreeable regional arrangements with respect to RTO formation and coordination."[77] As described by former FERC Commissioner Vicky Bailey in Exhibit E, the Commission wanted to encourage participation in RTOs, but did not believe that RTO membership was "a flat prerequisite to the provision of just and reasonable, non-discriminatory transmission service."[78]

The Commission has not mandated RTO membership. While the Commission considered the possibility of more expansive RTO participation under Standard Market Design

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[73] *Id.* at 25:11-17 (July 20, 2005)

[74] *Kentucky Regulators Delay Decision on Whether LG&E, KU Should Withdraw From MISO; MISO Chief Suggests Their Withdrawal Will Have Little Impact*, FOSTER ELECTRIC REPORT, Aug. 25, 2004, at 2.

[75] KPSC Case No. 2003-00266, Transcript of Evidence (Volume I) at 19:14 to 20:7 (July 20, 2005).

[76] Dr. McNamara testified that none of the Midwest ISO stakeholders intervened in the KPSC proceeding. *See* KPSC Case No. 2003-00266, Transcript of Evidence (Volume I) at 25:6-10 (July 20, 2005).

[77] Order No. 2000 at 31,033.

[78] Bailey Testimony at 8.

("SMD"), such a rule was not ultimately adopted.[79] Also, in 2002, the U.S. Court of Appeals for the District of Columbia Circuit found that the Commission cannot require blanket RTO membership.[80] The Court stressed that the FPA does not provide the Commission with the power "to *compel* any particular interconnection or technique of coordination"[81] or to "prohibit [entities] from ending their voluntary coordination and interconnection through [an RTO]."[82]

Applicants note further that the Commission has effectively permitted other public utilities to completely forgo merger conditions similar to those currently applicable to Applicants.[83] Unlike other such public utilities, Applicants submit herein a proposal that meets the goals of Applicants' Merger Conditions. It would be inconsistent for the Commission to reject Applicants' ITO/Reliability Coordinator proposal because it does not comply with the Merger Conditions, while continuing to let other public utilities forgo merger obligations which have never been met.

Finally, Applicants note that the Commission has accepted Entergy's ICT proposal and is considering similar proposals by MidAmerican and Duke. Applicants' ITO/Reliability Coordinator proposal complies with the Entergy ICT Order, but also represents a refinement of that plan. For example, unlike the Entergy and Duke proposals, Applicants' proposal involves a separate Reliability Coordinator that will not only provide security coordination services, but will also oversee the transmission planning function. If the Commission approves the Entergy, Duke or MidAmerican proposals, it should also approve Applicants' proposal.

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79 *Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Notice of Proposed Rulemaking, FERC Stats. & Regs. ¶ 32,563 (2002). *See also Remedying Undue Discrimination through Open Access Transmission Service and Standard Electricity Market Design*, Order Terminating Proceeding, 112 FERC ¶ 61,073 (2005).

80 *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1 (D.C. Cir. 2002).

81 *Id.* at 12, citing *Duke Power Co. v. FERC*, 401 F.2d 930, 943 (D.C. Cir. 1968 (emphasis in original).

82 *Id.*

83 In 2000, CP&L Holdings ("CP&L") and Florida Progress Corporation ("Progress") sought Commission approval of their proposed merger and addressed concerns about vertical competition by committing to participate in Commission-approved RTOs. *See CP&L Holdings, Inc.*, 92 FERC ¶ 61,023 at 61,055 (2000). In granting its approval, the Commission relied on these RTO commitments and stated "we accept Applicants' RTO commitments and rely on them in approving this merger." *Id.* at 61,056. Subsequently, all efforts to develop RTOs in the Southeast and Florida stalled, but the Commission has never enforced the merger conditions.

B. The Proposed Open Access Transmission Tariff is Just and Reasonable.

Applicants hereby file a revised *pro forma* OATT that: (i) implements the RDMP; (ii) institutes the ITO and the Reliability Coordinator as third parties acting as tariff administrator and reliability coordinator for the Transmission System, respectively; (iii) maintains the same transmission rate levels (and rate formula) currently charged by the Midwest ISO for transmission service on Applicants' system (*i.e.*, Attachment O); and (iv) contains the same ancillary service rates that Applicants charge today.

This *pro forma* OATT contains revisions to the OATT that is currently on file with the Commission.[84] Applicants have red-lined the OATT against various operable documents for ease of comparison.[85] Attached hereto as Exhibit A-1 are the red-lined portions of the OATT, as well as a chart which notes the various sections of the OATT, and the documents against which those sections have been redlined. The chart also references the source of support for the reasonableness of the provisions in question.

As described below, the OATT should be accepted for filing. All of the rates in the new OATT are just and reasonable because, in each instance, such rates reflect either: (i) language changes and provisions which are necessary to implement the ITO and the Reliability Coordinator; (ii) rates that are currently on file and charged by Applicants; (iii) rates that have been accepted by the Commission in other dockets; or (iv) rates that have been filed by other public utilities in other dockets and that Applicants now propose here, subject to the outcome of Commission decisions in those dockets.

The following is an overview and key highlights of Applicants' proposed OATT.

- The Body of the OATT follows the Commission's *pro forma* OATT as closely as possible, and tracks the body of Applicants' OATT which is currently on file with

[84] On January 31, 2002, Applicants cancelled certain portions of their OATT in order to facilitate the offering of transmission services over the Transmission System under the Midwest ISO's OATT. Since Applicants would no longer be offering base transmission service under their own OATT, certain portions of their OATT became inapplicable. The cancelled portions of the Applicants' OATT included Schedule 7 ("Long-Term Firm and Short-Term Firm Point-to-Point Transmission Service) and Schedule 8 (Non-Firm Point-to-Point Transmission Service). In addition, Applicants replaced all their Attachments (A through I) with a single Attachment A (Form of Service Agreement for Ancillary Services). The remaining portions of Applicants' OATT remained in effect, as the Midwest ISO has continued to rely on Applicants' OATT as the applicable rate schedule for Applicants' sales of ancillary services.

[85] Attachments E, L, and M and Schedule 9, which are original documents, have not been compared to any other operable documents. In addition, Attachment O is the same Attachment O contained in the Midwest ISO TEMT and, therefore, requires no red-lined comparison.

the Commission. Applicants have made minor modifications to the main body of the OATT to reflect the division of responsibilities between Applicants (referred to as the "Transmission Owner"), the ITO, and the Reliability Coordinator.

- <u>Attachments A through K</u>: (i) were part of the Applicants' prior OATT and have been merely re-filed with changes to reflect the division of responsibilities between the Applicants, the ITO, and the Reliability Coordinator; or (ii) reflect changes to the *pro forma* OATT required by the Commission subsequent to Applicants transitioning to the Midwest ISO's OATT (*e.g.*, LGIA/LGIP and SGIA/SGIP).[86] One exception is Attachment C, which contains a revised and updated methodology for assessing Available Transmission Capability ("ATC"). These Attachment C revisions were based on the Attachment C contained within the Duke Energy Corporation OATT (*i.e.*, the OATT that is proposed to govern Duke's independent transmission coordinator proposal, which is similar to the Applicants' proposal contained herein). Because this ATC function will be performed by SPP, Applicants recognize that it may need to revise this Attachment C as appropriate to reflect the ATC calculation methodology that SPP deems appropriate. Such revisions will be made upon conclusion of Applicants' negotiations with SPP.

- <u>Attachments L and M</u> provide for and delineate the functions of the ITO and the Reliability Coordinator. Attachment L sets forth the functions of these entities in tariff language. Attachment M appends to the OATT the *pro forma* bilateral agreements between Applicants and the ITO and the Reliability Coordinator. As noted above, the TVA *pro forma* agreement and the portions of Attachment L that establish the role of the Reliability Coordinator are included in the OATT for informational purposes only. Attachments L and M are discussed in detail below.

- <u>Attachment N</u> provides for cost recovery for system expansions and transmission upgrades. It defines the different kinds of transmission expansions and upgrades and determines the pricing for and the rights associated with Supplemental Upgrades. This Attachment has been modeled after a similar Attachment proposed by Entergy.[87]

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[86] *See Standardization of Small Generator Interconnection Agreements and Procedures*, Order No. 2006, 111 FERC ¶ 61,220 (2005); *Standardization of Generator Interconnection Agreements and Procedures,* Order No. 2003, FERC Stats. & Regs. ¶ 31,146 (2003), *on reh'g,* Order No. 2003-A, 106 FERC ¶ 61,220 (2004), *on reh'g,* Order No. 2003-B, 109 FERC ¶ 61,287 (2004), *on reh'g*, Order No. 2003-C, 111 FERC ¶ 61,401 (2005).

[87] On March 22, 2005, the Commission approved the Entergy transmission pricing proposal for a two-year experimental basis and directed Entergy to enhance and modify its proposal in a subsequent filing. *See Entergy*

- Attachment O appends Attachment O of the Midwest ISO's TEMT to Applicants' OATT. Applicants currently receive revenue from the Midwest ISO for transmission service provided by the Midwest ISO pursuant to rates charged under Attachment O. Thus, Applicants propose to charge the same rates as are charged to customers today, and apply the same formula for rate setting which would be otherwise applicable.

- Ancillary Service Schedules: Applicants have not made any substantive revisions to Schedules 1 through 6. These schedules reflect the ancillary services schedules that are currently on file in Applicants' existing OATT and pursuant to which Applicants currently sell ancillary services. Applicants have made only minor revisions to the language of Schedules 1 through 6 to reflect the division of responsibilities between the ITO and the Reliability Coordinator.

- Point to Point and Network Service: Schedules 7 through 9 reference and reflect the formula rate set forth in the Midwest ISO's TEMT Attachment O. These schedules have also been revised to include language reflecting the RDMP and the inclusion of Reciprocity Firm service, as discussed above.

- Loss Compensation Service: Schedule 10 (Loss Compensation Service) is modeled after similar schedules the Commission has approved in other OATTs.[88] This Schedule 10 will only apply to transmission service arrangements entered into after the effective date of the revised tariff. That is, existing transmission arrangements will not be subject to Applicants' submitted Schedule 10.

1. The ITO and the Reliability Coordinator (Attachment L)

Attachment L of Applicants' OATT sets forth the division of functions, rights, and responsibilities of the ITO and the Reliability Coordinator. Attachment L details how the ITO and Reliability Coordinator will perform their oversight of Applicants' transmission system and specifies the scope of their functions, rights, and responsibilities. In order to further explain the relationship between the ITO, the Reliability Coordinator, Applicants, and the other market participants, and the communications links and coordination points between them, Applicants

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Services, Inc., 110 FERC ¶ 61,295 at P 66, 68 (2005), *on clarification*, 111 FERC ¶ 61,222 (2005). On May 27, 2005, in Docket No. ER05-1065-000, Entergy filed revisions to its tariff in compliance with the Commission's orders. Included in this May 27, 2005 filing was Entergy proposed Attachment T (Recovery of New Facilities Costs) on which Applicants' Attachment N is based. *See* Exhibit A for a red-lined comparison of Applicants' Attachment N and Entergy proposed Attachment T.

[88] In particular, Applicants' Schedule 10 is modeled after Duke Energy Corporation's OATT Schedule 10.

have attached to this filing (*see* Exhibit K) a list of primary responsibilities and support functions for each entity and a matrix showing the interaction of such responsibilities/functions.

Below is a description of the major aspects of the roles and responsibilities of the ITO and the Reliability Coordinator as provided for under Attachment L. These functions are also explained in the testimony of Mark S. Johnson, Exhibit F hereto.

a. The ITO

The following discussion highlights key elements of Attachment L, including: (i) the ITO's independence; (ii) the ITO's role in taking transmission service requests and in setting ATC and TTC; (iii) the ITO's oversight of generator interconnections; (iv) the ITO's oversight of the stakeholder process; and (v) the ITO's involvement in seams management.

i. ITO Independence

Attachment L contains numerous provisions to ensure that the ITO will be truly independent from Applicants and other market participants.

- Attachment L bars both the ITO and its employees from being affiliated with Applicants, any transmission customer, or any market participant. *See* § 3.2.

- Attachment L prohibits the ITO from discriminating against any transmission customer, and includes measures to ensure that the ITO will have no incentive to discriminate in favor of Applicants' merchant generation division. *See* § 3.3.

- Attachment L makes all employees of the ITO subject to the Commission's Order No. 2004 Standards of Conduct and equivalent to Applicants' transmission-function employees. Moreover, Attachment L requires the ITO to develop and post certain policies on the Applicants' OASIS to prevent conflicts of interest or other ethical concerns that could bias the ITO in favor of any market participant. *See* § 3.3.1.

- Finally, to allow the ITO to fulfill its role without any perceived or actual interference from Applicants, Attachment L grants the ITO access to any transmission information that it needs to carry out its functions, subject to the protection of any Critical Energy Infrastructure Information and other confidential information. *See* §§ 3.5, 4.4.

ii. Transmission Service Requests, TTC/ATC Calculations and OATT/OASIS Administration by ITO

Under Attachment L:

- The ITO shall administer the terms and conditions of Applicants' OATT. *See* § 4.1.

- The ITO will calculate TTC and ATC, process all requests for transmission service, and administer Applicants' OASIS site. *See* § 6.6. The Commission has determined that having an independent party serve these roles addresses concerns that the transmission owner could manipulate TTC and ATC calculations or transmission service denials.[89]

- The ITO will have sole authority to accept or reject requests for transmission service on a non-discriminatory basis, including requests under network service and existing point-to-point service agreements. The ITO shall document all transmission service requests, whether the request was granted or denied, and the supporting data underlying the ITO's ultimate decision. *See* § 6.

- In processing transmission service requests, the ITO will be responsible for: (i) performing any System Impact Studies required by Applicants' OATT; (ii) providing the transmission customer with the Facilities Study Agreement; and (iii) coordinating, overseeing and finalizing Facilities Studies. The ITO will have discretion to coordinate with Applicants, when it deems it necessary, to obtain information that may assist in the evaluation of requests for service over Applicants' transmission or distribution facilities. *See* § 6.

- The ITO will administer Applicants' OASIS for purposes of processing and evaluating transmission service requests ("TSRs") and ensuring the Applicants' compliance with the obligation to post publicly transmission-related information. The ITO will fulfill the obligations of the "Responsible Party" under 18 C.F.R. § 37.5 (2005) and post all information required to be posted on OASIS under 18 C.F.R. § 37.6 (2005). For instance, the ITO will be responsible for maintaining queues of transmission requests and for calculating and posting TTC and ATC values on the OASIS. *See* §§ 6.1, 6.6, and 6.8.

- The ITO shall determine all TTC and ATC calculations in a manner consistent with the terms of the Applicants' OATT and ensure that all TTC and ATC values are calculated on a non-discriminatory basis. Further, ATC shall be calculated by the ITO on a control area-to-control area basis for Applicants' control area interfaces. Applicants are

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89 *See Am. Elec. Power Co.*, 90 FERC ¶ 61,242 at 61,789 (2000).

responsible for providing the ITO with all information necessary for the ITO to fulfill its OASIS posting and TTC/ATC calculation responsibilities. *See* § 6.

iii. Generator Interconnection Process Overseen by ITO

In recent years, the Commission has standardized the process by which generators may secure interconnections to the transmission systems of public utilities.[90] While adopting these standardized processes in its OATT, Applicants also propose that the ITO process all interconnection requests.

Specifically, under Attachment L:

- The ITO will have the authority to receive, evaluate, and respond to all requests for generator interconnection. This will include: (i) implementing and applying Applicants' generator interconnection procedures in accordance with the terms in Attachments J and K; (ii) queuing all interconnection requests; (iii) performing studies necessary to evaluate the interconnection requests; and (iv) developing transmission system modeling processes, software and assumptions used to evaluate interconnection requests. *See* § 7.1.

- As Transmission Owners, Applicants will continue to maintain responsibility for developing and filing with the Commission procedures for any Interconnection Impact Studies. The ITO, however, will assume full responsibility for performing the Interconnection Feasibility Study and Interconnection Impact Study in accordance with the LGIP/SGIP procedures. *See* § 7.2.

b. The Reliability Coordinator

The Reliability Coordinator will perform all functions identified for Reliability Coordinators under NERC Version 0 Reliability Standards,[91] while Applicants will retain all

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90 *See supra* n. 86.

91 NERC's Operating Reliability Subcommittee specifies the specific NERC Version 0 Reliability Standards that implicate Reliability Coordinators. These standards include: (i) TOP-001-0 ("Reliability Responsibilities and Authorities"); (ii) TOP-003-0 ("Planned Outage Coordination"); (iii) TOP-005-0 ("Operating Reliability Information"); (iv) TOP-006-0 ("Monitoring System Conditions"); (v) COM-001-0 ("Telecommunication"); (vi) COM-002-0 ("Communications and Coordination"); (vii) EOP-002-0 ("Capacity and Energy Emergencies"); (viii) EOP-004-0 ("Disturbance Reporting"); (ix) EOP-006-0 ("Reliability Coordination - System Restoration"); (x) EOP-008-0 ("Plans for Loss of Control Center Functionality"); (xi) CIP-001-0 ("Sabotage Reporting"); (xii) PER-004-0 ("Reliability Coordination - Staffing"); (xiii) IRO-001-0 ("Reliability Coordination - Responsibilities and Authorities"); (xiv) IRO-002-0 ("Reliability Coordination - Facilities"); (xv) IRO-003-0 ("Reliability Coordination - Wide Area View"); (xvi) IRO-004-0 ("Reliability Coordination - Operations Planning"); (xvii) IRO-005-0 ("Reliability Coordination - Current Day Operations"); and (xviii) IRO-006-0 ("Reliability Coordination - Transmission Loading Relief"), *available at* http://www.nerc.com/~oc/ors.html.

remaining NERC obligations. Applicants will retain the ability to address reliability problems through their role as control area operator and take action necessary to protect reliability of the Applicants' Transmission System, including circumstances where such action is necessary to protect, prevent or manage emergency situations.

In addition, as set forth in Attachment L, the Reliability Coordinator will perform certain other functions, including: (i) transmission planning and regional coordination; (ii) approving Applicants' maintenance schedules; (iii) identifying and mandating upgrades required to maintain reliability; (iv) non-binding recommendations relating to economic transmission system upgrades; and (v) administration of any seams agreements.

i. Security Coordination

The Reliability Coordinator will perform its security coordinator functions in accordance with Good Utility Practice and shall conform to: (i) all applicable reliability criteria, policies, standards, rules, regulations, and other requirements of NERC and any applicable regional reliability council or their successors; (ii) the Transmission Owner's specific reliability requirements and operating guidelines; and (iii) all applicable requirements of federal and state regulatory authorities. Most importantly, as noted above, the Reliability Coordinator will perform all functions identified for Reliability Coordinators under NERC Version 0 Reliability Standards. *See* Attachment L § 8.2.

ii. Transmission Planning and Upgrades

The Reliability Coordinator will oversee Applicants' transmission planning efforts to ensure that reliability and upgrade needs are met and that such transmission planning is conducted on a non-discriminatory basis. The Reliability Coordinator will serve as Applicants' Transmission Planning Authority – the same role currently being filled by the Midwest ISO. *See* Attachment L § 13.

In addition, as set forth in Attachment L:

- The Reliability Coordinator will review Applicants' proposed maintenance schedules and either approve or deny such maintenance schedules based on reliability considerations. *See* § 10.1.

- The Reliability Coordinator will review and approve Applicants' Planning Criteria, as defined in Section 2.10 of Attachment L, in order to ensure that these criteria are sufficiently transparent and understandable. *See* § 13.1.3.

- The Reliability Coordinator will review and approve Applicants' Base Case Model for the transmission system that reflects annual and seasonal power flows. This model will include all existing long-term, firm uses of the transmission system, including: (i) Network Integration Transmission Service; (ii) firm transmission service for Applicants' Native Load; (iii) long-term point-to-point transmission service; and (iv) firm transmission service provided in accordance with grandfathered agreements. The Reliability Coordinator will ensure that the Base Case Model is consistent with Applicants' Planning Criteria. *See* §§ 13.1.4, 13.4.

- Applicants will develop an Annual Plan, which will contain all transmission upgrade projects on its transmission system that are necessary to satisfy the Planning Criteria and the Base Case Model. This Annual Plan will be submitted to the Reliability Coordinator, who will perform an independent reliability assessment and evaluation of the Annual Plan and makes suggestions to Applicants. After the Annual Plan has been finalized, the Reliability Coordinator will transfer the Annual Plan to the ITO for posting on OASIS. *See* § 13.5, 13.1.5, and 13.1.6.

- The Reliability Coordinator will identify any instances where it does not agree with Applicants' Annual Plan and provide Applicants with an opportunity to provide any revisions. *See* §13.1.8.

2. ITO and the Reliability Coordinator Agreements and RFP Process (Attachment M)

As part of their proposal to withdraw from the Midwest ISO and ensure a substantial level of independence in the operation of their transmission system, Applicants will enter into separate agreements with the ITO and the Reliability Coordinator, as more fully described below. *Pro Forma* versions of these agreements are appended to the OATT as Attachment M.[92] The agreements document the commercial relationship between Applicants and the ITO and the Reliability Coordinator, and reflect (and will continue to reflect) the key terms provided for in Attachment L.

In the preceding months, Applicants have issued two Requests for Proposals ("RFPs") for the performance of ITO and Reliability Coordinator functions. As explained in more detail in the attached testimony of Mark S. Johnson, the ITO RFP was issued to seven parties on August 22, 2005 and included a response deadline of September 8, 2005.[93] The Reliability Coordinator RFP was sent to four entities on August 10, 2005 and included a response deadline of August 24,

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92 As of the date of this filing, the ITO and Reliability Coordinator Agreements have not been finalized and executed by the parties. Applicants will amend this application when these Agreements have been finalized and replace the *pro forma* agreements with the executed agreements.

93 Johnson Testimony at 4.

2005.[94] The Reliability Coordinator RFP was only issued to a select number of entities because those entities are the only NERC-certified reliability coordinators capable of providing the required reliability functions that Applicants are seeking to outsource.

Below, Applicants discuss the benefits of SPP acting as the ITO, and TVA acting as the Reliability Coordinator, and, in particular, why these entities were selected in the RFP process.

a. SPP as the ITO

Applicants selected SPP as the winner of the ITO RFP. Negotiations with SPP are ongoing. Applicants will file an executed version of their agreement with SPP in this docket as a filing amendment when that agreement is finalized.

SPP was selected based on several factors. First, Applicants believe that SPP is sufficiently independent and the Commission has already deemed SPP an appropriate entity for serving as an independent overseer of transmission. In the Entergy ICT Order, which approved Entergy's ICT proposal, the Commission specified that any entity serving as an independent coordinator of transmission "must be, in both perception and in reality, entirely independent" from the public utility.[95] The Commission found that SPP, as a Commission-approved RTO that complies with the independence requirements of Order No. 2000, satisfies this independent standard.[96]

Second, although SPP is physically removed from the Applicants' Transmission System, Applicants believe that physical proximity to or an interconnection with Applicants is not required for SPP to perform its ITO services. Rather, ITO services can be handled remotely with the appropriate computer software, data, and communication links and personnel. In fact, Applicants believe that SPP's location may actually further its role as an independent overseer of Applicants' system. Since the Applicants' Transmission System is not physically connected with the SPP transmission system, there is no incentive for SPP to administer Applicants' OATT in a manner that creates advantages for its own footprint.

Third, Applicants believe that SPP is uniquely qualified to perform the required services. Not only is SPP sufficiently independent from market participants, but it also has the experience, personnel, platform, and infrastructure to perform the required functions. SPP should be able to "hit the ground running" and start performing its ITO functions in a very short amount of time.

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94 *Id.*

95 Entergy ICT Order, 110 FERC at P 35.

96 *Id.*

Moreover, while Applicants believe that SPP is the uniquely qualified to serve as ITO, Applicants' note that SPP was the only Commission-approved RTO willing to offer Applicants unbundled ITO services (notwithstanding the fact that other RTOs have in the past offered unbundled Reliability Coordination and tariff administration services to certain entities – *e.g.*, MAPP utilities and Duke).

b. TVA as the Reliability Coordinator

On August 30, 2005, Applicants selected TVA as the Reliability Coordinator. Applicants have entered into negotiations with TVA regarding a Reliability Coordinator Agreement. The *pro forma* agreement is included as Attachment M of the OATT. However, the agreement has not been finalized. On September 27, 2005, Applicants entered into a letter of intent with TVA regarding the provision of reliability coordination services which is attached hereto as Exhibit J.

Applicants selected TVA as Reliability Coordinator based on a combination of its: (i) operational capabilities and experience; (ii) geographic location and interconnectivity; (iii) pre-existing seams agreements (as discussed above); and (iv) lowest cost bid. However, there are numerous other benefits in selecting TVA as Reliability Coordinator.

First, TVA, as a governmental entity, has many unique characteristics to ensure that it will remain independent from Applicants and perform its Reliability Coordinator functions in a non-discriminatory manner. Unlike a for-profit, electric utility seeking to maximize profits, TVA is a government corporation charged with providing electric power, flood control, navigational control, agricultural and industrial development, and other services to a region including Tennessee and parts of six contiguous states.

Also, the Tennessee Valley Authority Act of 1933 ("TVA Act") effectively eliminates any TVA incentive to discriminate against Applicants or any other market participant. Section 15d(a) of that Act prohibits TVA from making contracts for the sale or delivery of power that have the direct or indirect effect of making it a source of power supply outside a statutorily defined area.[97] This provision is generally referred to as the "fence" and, with limited exceptions,[98] effectively prohibits the direct or indirect marketing of TVA generated power outside the TVA footprint. The fence was erected to protect utilities from having to compete

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[97] 16 U.S.C. § 831n-4(a) (2000).

[98] TVA is permitted to make limited sales to certain neighboring utilities, including LG&E and KU. This limited ability is important in order to ensure that TVA may effectively engage in congestion management and redispatch involving its generation.

against TVA power because of the privileges, benefits, and competitive advantages TVA possesses as a government corporation.[99]

Given that TVA is generally prohibited from selling power outside "the fence," TVA has no incentive to use its role as Reliability Coordinator to benefit itself at the expense of another market participant. Further, TVA is bound by its own Standards of Conduct, which state that it "shall treat all Transmission Customers, affiliated and non-affiliated, on a nondiscriminatory basis, and, to the extent consistent with the TVA Act and other applicable law, shall not operate its transmission system to preferentially benefit [TVA's Bulk Power Trading unit]."[100] Finally, since TVA has no stake in wholesale markets outside "the fence," it has no ability to discriminate against one market participant in favor of another.

Second, the selection of TVA as Reliability Coordinator makes sense when one looks at the existing relationship between TVA and the Commonwealth of Kentucky. TVA is already the Reliability Coordinator for EKPC and BREC and Applicants' control area is embedded in TVA's reliability footprint.[101] Early in their participation in the Midwest ISO, Applicants were concerned about the Midwest ISO's role as Reliability Coordinator given TVA's similar role for EKPC and BREC. Applicants urged the Midwest ISO to enter into seams and congestion management agreements with TVA to alleviate these coordination concerns between the two Reliability Coordinators. TVA serving as the Reliability Coordinator for Applicants, EKPC, and BREC, alleviates any residual Midwest ISO-TVA coordination concerns.

Third, it is likely that the regional transmission grid will benefit from TVA serving as the Reliability Coordinator. Under Applicants' proposal, TVA, as Reliability Coordinator, will not only be performing security coordination for Applicants, but will also oversee transmission planning of Applicants' system. Such oversight will undoubtedly create synergistic opportunities for increasing the interface capacity between Applicants, TVA, and others within the TVA reliability area. Also, by TVA overseeing the transmission planning function for Applicants' footprint, there will be greater focus (of attention and resources) on the Applicants/TVA regional grid. Under the Midwest ISO's transmission planning regime, Kentucky's planning interests were subject to Midwest ISO-wide planning priorities. Applicants' proposal will provide better focus to the Applicants/TVA footprint and hopefully facilitate additional interconnects between the two systems.

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99 *Hardin v. Kentucky Utilities Co.*, 390 U.S. 1, 7 (1968) ("it is clear and undisputed that protection of private utilities from TVA competition was almost universally regarded as the primary objective of the [fence]").

100 *See* Tennessee Valley Authority Standards of Conduct for Transmission Providers, August 2005 Edition, <http://www.oatioasis.com/tva/tvadocs/TVA_StandardsOfConduct.pdf>.

101 *See* TVA Reliability Area Maps, Exhibit I hereto.

Finally, Applicants note that they are filing the *pro forma* reliability coordination agreement with TVA, as well the TVA-applicable provisions of OATT Attachment L (establishing, among other things, the role of the Reliability Coordinator), for informational purposes only. The reliability coordination agreement and TVA, in its role as Reliability Coordinator, do not fall within the Commission's jurisdiction.

3. Recovery of New Facility Costs (Attachment N)

Attachment N provides cost recovery for system expansion and transmission upgrades and has been modeled after a similar proposal submitted by Entergy Services, Inc. in Docket No. ER05-1065-000 on May 27, 2005. The cost allocation for upgrades and expansions is driven by the Reliability Coordinator's Base Case Model, as discussed above. The Base Case Model includes system expansions or upgrades that are necessary to meet reliability standards on Applicants' transmission system. Base case investments are eligible for recovery in transmission rates, as specified in Attachment N. System expansions and upgrades not included in the Base Case Model are considered Supplemental Upgrades and are paid for by the requesting party. Under the provisions of Attachment N, the Reliability Coordinator will determine whether a proposed upgrade should be considered a Base Case Upgrade or a Supplemental Upgrade.

a. Pricing of Supplemental Upgrades

The costs of Supplemental Upgrades that are required to grant point-to-point transmission service will be recoverable under the Commission's "higher of" pricing policy. In particular, the transmission customer requesting the service will be charged the higher of: (i) the applicable point-to-point rate recoverable over the requested term of service, factoring the cost of the upgrade into the rate; or (ii) the incremental cost of the upgrade plus any financial compensation payments due to other transmission customers as specified in Attachment N.

The cost of Supplemental Upgrades required to accommodate network customer service requests, including designation of new NITS Network Resources, will be recovered from the requesting network customers. Network customers will be charged the cost of the upgrade plus any financial compensation payments due to other customers.

Similarly, the cost of Supplemental Upgrades required to accommodate requests for Energy Resource Interconnection Service ("ERIS") or Network Resource Interconnection Service ("NRIS") will be recovered from the Interconnection Customer. The Interconnection Customer will be charged the cost of the upgrade plus any financial compensation payments due to other customers.

The cost of all other Supplemental Upgrades will be recovered from the requesting customer. The requesting customer will be charged the cost of the upgrade plus any financial compensation payments due to other customers.

b. Comparability

The provisions of Attachment N will apply to Applicants and their affiliates, including requests for transmission service on behalf of Applicants' bundled retail load, and requests for point-to-point transmission service into, out of, or across the Transmission System by Applicants' affiliates or their wholesale merchant functions. Any Supplemental Upgrades are funded by Applicants on behalf of their bundled retail load will be eligible for recovery through Applicants' bundled retail rates and will not be recovered through transmission rates. Recovery of the cost of Supplemental Upgrades from GFA customers will be governed by the particular provisions of each GFA.

c. Rights Associated With Supplemental Upgrades

Under the provisions of Attachment N, when a customer uses the capacity created by a Supplemental Upgrade that it funded, the customer shall not be charged congestion for its use of that capacity. Further, a customer who obtains transmission service by funding a Supplemental Upgrade will receive firm service, subject to the same curtailment priority as other firm service under the OATT. In addition, a customer funding a Supplemental Upgrade will receive a financial payment if additional long-term point-to-point transmission service, the designation of a long-term network resource (*i.e.*, the designation of a Network Resource for a period of at least one year), or NRIS or ERIS status is subsequently granted to another customer using the facility that was created or expanded by the funding customer's Supplemental Upgrade. A customer that has funded a Supplemental Upgrade in order to qualify a generating resource at the NITS, NRIS or ERIS level will receive an equivalent financial compensation payment if that same customer obtains long-term point-to-point transmission service out of the generating resource and that point-to-point service uses transmission capacity that was originally funded through the Supplemental Upgrade

The Reliability Coordinator will review all requests for long-term point-to-point, long-term network resources, or NRIS or ERIS status to determine whether the granting of such service is dependent on previously funded Supplemental Upgrades. If the Reliability Coordinator determines that the respective service does depend on previously funded Supplemental Upgrades, the requesting customer will be offered the service/status according to the terms contained within Sections 4.3.4 and 4.3.5 of Attachment N.

4. Formula Rate (Attachment O)

Applicants propose to adopt the Midwest ISO's Attachment O and make it part of their OATT. Under the Midwest ISO's Attachment O rate formula, which has been approved by the

Commission,[102] rates for each transmission-owning member of the Midwest ISO are updated effective June 1 of each year, based on FERC Form No. 1 data of each transmission-owning Midwest ISO member for the previous calendar year.

The Commission should approve Applicants' adoption of Attachment O because: (i) the Attachment O formula has been previously approved by the Commission; (ii) Applicants' transmission rates will continue to be formulated in the same way and, therefore, will remain unchanged following their withdrawal from the Midwest ISO; and (iii) the Attachment O formula rate uses publicly available and readily ascertainable historical FERC Form 1 data.

C. The Effect on Applicants' (and Their Affiliates') Market-Based Rate Authority.

Applicants and their affiliates, LEM and Western Kentucky Energy Corporation ("WKEC"), have all received blanket authority to sell electric capacity and energy at market-based rates.[103] Applicants first received blanket market-based rate authority from the Commission in 1998.[104] LEM received such authority in 1994,[105] and WKEC received such authority in 1998.[106] On November 19, 2004, Applicants, LEM, and WKEC submitted to the Commission an updated generation market power analysis in compliance with *Acadia Power*

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[102] On January 15, 1998, in Docket No. ER98-1438-000, the Midwest ISO Transmission Owners filed Attachment O as the formula rate template under the Midwest ISO's OATT. On September 16, 1998, the Commission conditionally approved the Midwest ISO as an independent transmission system operator and instituted hearing procedures on several issues, including the formula rate template, which were later resolved. *See Midwest Indep. Transmission Sys. Operator, Inc.*, 87 FERC ¶ 61,189 (1999). Since it was originally accepted, Attachment O has been occasionally revised. *See, e.g.*, *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,052 (2005) (approving revisions to Attachment O following July 8, 2004 and October 28, 2004 Commission orders); *Midwest Indep. Transmission Sys. Operator, Inc.*, 111 FERC ¶ 61,131 (2005) (approving a settlement involving the Midwest ISO Attachment O formula which derives the transmission charges for all customers in the American Transmission Systems Incorporated ("ATSI") zone).

[103] Applicants, LEM, and WKEC are the only affiliates with market-based rate authority.

[104] *See supra* n.15.

[105] *LG&E Power Mktg., Inc.*, 68 FERC ¶ 61,247, *modified on other grounds*, 69 FERC ¶ 61,153 (1994). LEM was formerly known as LG&E Power Marketing Inc. *See* Notice of Name Change, Docket No. ER97-3418-000, Jun. 24, 1997.

[106] *WKE Station Two Inc.*, 82 FERC ¶ 61,178 (1998) (accepting for filing market-based rate tariffs of WKEC and WKE Station Two Inc., since cancelled).

Partners, LLC.[107] That filing demonstrated that Applicants, LEM, and WKEC passed the Commission's pivotal supplier screen in all relevant control areas but failed the market share screen in Applicants' control area and the adjacent BREC control area.[108]

On May 5, 2005, the Commission issued an order which, *inter alia*, instituted an investigation under Section 206 of the Federal Power Act to determine whether Applicants, LEM, and WKEC may continue to charge market-based rates in these two control areas.[109] With respect to Applicants' market-based rate authority in their own control area, the May 5 Order required Applicants, LEM, and WKEC to file a revised generation market power analysis using the footprint of the Midwest ISO, rather than Applicants' control area, as the relevant geographic market.[110] Accordingly, on June 6, 2005, Applicants, LEM, and WKEC filed with the Commission a generation market power analysis for the Midwest ISO market, showing that Applicants, LEM, and WKEC pass both the pivotal supplier and market share screens in this market (the "June 6 MBR Filing").

On February 10, 2005, the Commission issued *Reporting Requirement for Changes in Status for Public Utilities with Market-Based Rate Authority*, requiring entities with market-based rate authority to report to the Commission, within 30 days, "any change in status that would reflect a departure from the characteristics the Commission relied upon in granting [an entity] market-based rate authority."[111] Further, this order requires entities filing such a report to

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107 107 FERC ¶ 61,168 at P 7 (2004) ("*Acadia*"). On November 4, 2004, the LG&E Parties filed in the above-referenced dockets a request for a 10-day extension of time in order to permit them until November 19, 2004 to submit their joint updated market power analysis. The Commission has not yet acted on this request.

108 Although Applicants were members of the Midwest ISO at the time of the November 19 filing, the Midwest ISO's "Day 2" markets had not yet begun operation. Accordingly, the updated generation market power analysis submitted was conducted not on the Midwest ISO market, but rather, on the LG&E/KU control area market, among others. *See AEP Power Mktg., Inc.*, 107 FERC ¶ 61,018 at PP 187-88, *on reh'g*, 108 FERC ¶ 61,026 (2004) ("[A]pplicants located in ISO/RTOs with sufficient market structure and a single energy market may consider the geographic region under the control of the ISO/RTO as the default relevant geographic market for purposes of completing their analyses (e.g., PJM, ISO-NE, NYISO, and CAISO)…. The ISO/RTO-wide geographic market delineation would not be appropriate for Midwest ISO or SPP at this time because neither performs functions such as a single central commitment and dispatch.").

109 *LG&E Energy Mktg. Inc.*, 111 FERC ¶ 61,153 at P 3 and Ordering Para. (E) (2005).

110 The Commission stated that, alternatively, the LG&E Parties could explain why the LG&E/KU control area is the correct market for analysis and include with such explanation: (i) a Delivered Price Test analysis; (ii) proposed mitigation measures; or (iii) a commitment to adopt cost-based rates. *Id.* P 20, 26 & Ordering Para. (I).

111 110 FERC ¶ 61,097 at P 1 (2005) ("Changes in Status Order").

state the change of status will likely result in changes to results of the Commission's generation market power screens.[112]

While the Changes in Status Order does not speak directly to the issue presented by Applicants' withdrawal from the Midwest ISO, it is reasonable to consider Applicants' withdrawal a "change in status that would reflect a departure from the characteristics the Commission relied upon in granting [Applicants, LEM, and WKEC] market-based rate authority."[113] Accordingly, absent further guidance from the Commission on this issue, Applicants, LEM, and WKEC commit to file a "change in status" report with the Commission within 30 days of Applicants' withdrawal from the Midwest ISO.

V. SATISFACTION OF MERGER CONDITIONS UNDER FPA SECTION 203

A. Merger Conditions

As described above, Applicants have been a party, directly or indirectly, to three major merger transactions. Applicants obtained prior Commission approval of each of these transactions under FPA Section 203 through a demonstration that each transaction was "consistent with the public interest."[114] In particular, Applicants demonstrated that each proposed transaction will have no adverse effect on competition, rates, or regulation.[115] In reaching this determination in the KU Merger and the E.ON Merger transactions, the Commission relied in part on Applicant's Midwest ISO membership as a factor mitigating any potential competitive concerns.

In particular, in approving the Applicant's merger, the Commission stated that such Midwest ISO membership would help "ensure that that the merger will not adversely affect competition, rates or regulation."[116] In that same order, the Commission also stated that

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[112] *Id.* at P 75.

[113] *Id.* at P 1.

[114] 16 U.S.C. § 824b(a) (1994 & 2000).

[115] *See Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement*, Order No. 592, FERC Stats. & Regs. ¶ 31,044 at 30,111 (1996) ("Merger Policy Statement"), *reconsideration denied,* Order No. 592-A, 79 FERC ¶ 61,321 (1997); *Revised Filing Requirements Under Part 33 of the Commission's Regulations,* Order No. 642, FERC Stats. & Regs. ¶ 31,111 at 31,874-78 (2000) ("Order No. 642"), *on reh'g,* Order No. 642-A, 94 FERC ¶ 61,289 (2001).

[116] LG&E/KU Merger Order, 82 FERC at 62,214.

> [A]pproval of the merger is based on LG&E and KU's continued participation in the Midwest ISO. If LG&E and KU seek permission to withdraw from [the Midwest ISO], we will evaluate that request in light of its impact on competition in the KU destination markets, use our authority under section 203(b) of the FPA to address any concerns, and order further procedures as appropriate.[117]

Similarly, in its order approving the E.ON merger, the Commission relied in part on Applicants' continued participation in the Midwest ISO through at least 2002, and another FERC-approved RTO thereafter.[118] In particular, in its analysis of vertical competitive issues, the Commission found that Applicants lacked the ability to exploit their transmission assets to harm competition because they had transferred operational control of their transmission systems to the Midwest ISO, to remain members of the Midwest ISO at least until the end of 2002, and to be members of a Commission-approved RTO thereafter.[119]

Below, Applicants explain how the submitted proposal is consistent with the Merger Conditions and does not create any negative competitive or rate issues.

B. Applicants' Proposal Will Achieve the Same Objectives as Midwest ISO Membership.

In the context of these merger orders, Applicants' RTO membership was not viewed by either Applicants or the Commission as an end unto itself. Rather, it was viewed as a means to an end – a means to alleviate any residual concerns the Commission might have had with regards to the effect of those transactions on competition, rates, and/or regulation. Neither Applicants nor the Commission ever stated that membership in the Midwest ISO – or in any RTO – was the only means to achieving such an end. As indicated by the quotation above from the LG&E/KU Merger Order, the Commission itself contemplated that, at some point in the future, Applicants' may wish to revisit RTO membership. In her testimony, Ms. Bailey states that she originally supported Applicants' RTO membership merger conditions, but that those merger conditions were not meant to "mandate LG&E/KU's RTO membership indefinitely *per se*."[120]

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117 *Id.* at 62,222-23.

118 E.ON Merger Order at 61,283.

119 *Id.*

120 Bailey Testimony at 11.

Applicants' plan for withdrawal from the Midwest ISO provides for a comparable means to achieving this end. Indeed, as explained by Dr. Hieronymus in attached testimony, Applicants' proposal preserves the horizontal and vertical benefits of Midwest ISO membership.[121] This fact is particularly true when one looks in detail at what the Commission said about the key characteristics of ISOs and RTOs when accepting Applicants' RTO representations in the LG&E/KU and E.ON mergers.

In the LG&E/KU Merger Order, the Commission stated that ISOs separate "the control of transmission from generation,"[122] "reduce, if not eliminate altogether, any potential manipulation of the post-merger transmission system,"[123] and "ensure expansion of geographic markets by eliminating pancaked transmission rates" and offering "transmission service at a single rate."[124] In addition, the Commission also cited several other important ISO concepts, such as: (i) the establishment of an independent entity with "no economic stake in maintaining congestion interfaces;" (ii) the elimination of "the incentive to engage in strategic curtailments" of competitor generation; and (iii) the removal of all incentives to game OASIS operations.[125] In the E.ON Merger Order, the Commission stated that LG&E/KU's membership in the Midwest ISO or another RTO adequately protects competition because it removes LG&E/KU's "ability to exploit their transmission assets to harm competition in wholesale energy markets."[126]

The same benefits of an ISO or RTO membership identified in the LG&E/KU and E.ON merger orders are achieved through the ITO/Reliability Coordinator proposal. In fact, each of the Commission's reasons why Midwest ISO membership mitigates potential competitive concerns hold true for the Applicants' proposal as well. Dr. Hieronymus concludes that the ITO/Reliability Coordinator proposal is "consistent with commitments made by Applicants in prior merger proceedings and, further, will have no significant adverse competitive effects."[127] Also, Ms. Bailey, a former FERC Commissioner who voted on the Applicants original merger,

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121 Hieronymus Testimony at 5, 11.

122 LG&E/KU Merger Order, 82 FERC at 62,222.

123 *Id.*

124 *Id.*

125 *Id.* at n.39.

126 E.ON Merger Order, 97 FERC at 61,282.

127 Hieronymus Testimony at 1.

concludes in her testimony that the ITO/Reliability Coordination model should be deemed to meet the Applicants' merger conditions.[128]

C. Applicants' Withdrawal from the Midwest ISO, as Proposed Herein, Will Not Adversely Affect Competition, Rates, or Regulation.

In evaluating whether a proposed jurisdictional transaction is consistent with the public interest as required by FPA Section 203, the Commission evaluates whether the proposed transaction will have an adverse effect on competition, rates, or regulation.[129] In accordance with *Atlantic City Electric Company v. FERC,*[130] no FPA Section 203 application is required for Applicants to withdraw from the Midwest ISO. However, in an effort to alleviate any related concerns the Commission may have, Applicants demonstrate below that their withdrawal from the Midwest ISO will not have an adverse effect on competition, rates, or regulation.

1. Applicants' Withdrawal from the Midwest ISO Will Not Adversely Affect Competition in the Midwest ISO or LG&E/KU Markets.

In Order No. 642, the Commission stated that its objective in analyzing a proposed transaction's effect on competition is to determine whether such disposition "will result in higher prices or reduced output in electricity markets."[131] The Commission has held that higher prices and reduced output in electricity markets may occur if a FPA Section 203 applicant or applicants are able to exercise market power, either alone or in coordination with other firms.[132] Applicants' exit from the Midwest ISO will have no such adverse impact on either horizontal or vertical competition.

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128 Bailey Testimony at 11.

129 *See supra* n.115.

130 *See Atlantic City Elec. Co. v. FERC*, 329 F.3d 856 at 859 (D.C. Cir. 2003) (*per curiam*); *Atlantic City Elec. Co. v. FERC*, 295 F.3d 1 at 11 (D.C. Cir. 2002) (FERC exceeded its jurisdiction by directing utilities to modify their ISO Agreement to state that any notice of withdrawal from the ISO must receive FERC approval under Section 203 to become effective).

131 Order No. 642, FERC Stats. & Regs. at 31,879.

132 *Id.*

a. Applicants' Exit From the Midwest ISO Will Not Adversely Affect Horizontal Competition.

In the *Merger Policy Statement*, and affirmed in Order No. 642, the Commission adopted a "delivered price test" as a screen in order to measure the effect of a proposed transaction on the ability of entities to exercise market power in generation with respect to two measures of capacity – Economic Capacity and Available Economic Capacity.[133] Appendix A of the *Merger Policy Statement* details the analytic methodology that merger applicants must follow in their applications and that the Commission will use in screening the competitive impact of mergers (the "Competitive Analysis Screen").[134]

The Competitive Analysis Screen is intended for application to situations where two or more entities in the same or nearby geographic markets proposed to merger or otherwise transfer control of generating assets. It is not intended as a tool for analyzing general changes in market concentration resulting from, for example, possible changes in the definition of the market within which an existing entity operates. Thus, the Competitive Analysis Screen may be of only marginal use for analyzing the competitive effects of Applicants' exit from the Midwest ISO.

Nonetheless, Dr. Hieronymus has conducted such an analysis of market concentration in the Midwest ISO market and found that Applicants' withdrawal from the Midwest ISO will not adversely affect market concentration in the Midwest ISO market in any material manner.[135] Indeed, in all but one of the scenarios studied, the Midwest ISO market remains, even after Applicants' withdrawal, unconcentrated.[136] This one scenario should not be cause for concern, however, as concentration in the Midwest ISO market under this scenario will not increase by such an amount that would, in the context of a merger application, provide the Commission cause for concern.[137]

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133 Merger Policy Statement, FERC Stats. & Regs. at 30,130-32; Order No. 642, FERC Stats. & Regs. at 31,871-72.

134 Merger Policy Statement, FERC Stats. & Regs. at 30,128-37.

135 Hieronymus Testimony at 7.

136 *Id.* at 9.

137 For analyzing Section 203 merger applications, a "screen violation" is said to occur in a Competitive Analysis Screen if (i) the post-transaction HHI is greater than 1,800 and the transaction-induced HHI change is greater than 50, or (ii) the post-transaction HHI is between 1,000 and 1,800 and the transaction-induced HHI change is greater than 100. There is generally a "safe harbor" for transactions that result in a post-transaction HHI that is less than 1,000 notwithstanding the level of the transaction-induced HHI change. *See, e.g., Ameren Services Co.*, 101 FERC ¶ 61,202 at P 30 n.15 (2002); *CP&L Holdings, Inc.*, 92 FERC ¶ 61,023 at 61,053 n.14 (2000), *reh'g*

b. Applicants' Exit From the Midwest ISO Will Not Adversely Affect Vertical Competition.

In Order No. 642, the Commission set forth guidelines to be used in determining whether a proposed merger transaction will have an adverse effect on vertical competition.[138] Ordinarily, such concerns arise in circumstances in which the combined entity may restrict potential downstream competitors' access to upstream supply markets or increase potential competitors' costs. Applicants' proposed withdrawal from the Midwest ISO presents no such concerns. As explained above, Applicants are filing an OATT that will provide non-discriminatory open access to their transmission lines. This fact alone should be sufficient to alleviate any concerns that vertical competition may be adversely affected by a withdrawal from the Midwest ISO.[139] Regardless, Applicants' ITO/Reliability Coordinator proposal will ensure that they are unable to adversely effect vertical competition following their withdrawal from the Midwest ISO.

2. Applicants' Withdrawal from the Midwest ISO Will Not Adversely Affect Rates.

As noted in Part IV above, Applicants' filing is intended to have no impact on rates. There will be no change in transmission rates charged to Applicants' customers. Applicants will continue to offer de-pancaked transmission service, and will continue to charge Attachment O transmission rates and their existing ancillary service rates.

3. Applicants' Withdrawal from the Midwest ISO Will Not Adversely Affect Regulation.

In the context of a merger application under FPA Section 203, Order No. 642 provides that the Commission will evaluate the effect of a merger on regulation both at a federal and state level. There are no such concerns presented by the present filing. Applicants' proposal will neither change the state/federal regulatory jurisdictional boundaries nor create a regulatory gap. Also, the Commission's concern that state regulators should not be divested of authority to act on mergers of traditional, vertically-integrated utilities with captive retail (as well as wholesale)

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denied, 94 FERC ¶ 61,096 (2001); *IES Utilities, Inc.*, 78 FERC ¶ 61,023 at 61,093 n.12, *order affirming in part and denying in part*, Opinion No. 419, 81 FERC ¶ 61,187 (1997), *reh'g denied*, 82 FERC ¶ 61,089 (1998).

[138] Order No. 642, FERC Stats. & Regs. at 31,904-07.

[139] *See, e.g.*, *IES Utilities, Inc.*, 78 FERC ¶ 61,023 at 61,095 (1997) ("Applicants' open access tariffs mitigate any transmission market power they may possess post merger."). *See also* Order No. 888, FERC Stats. & Regs. at 31,656-57 ("In order to demonstrate the requisite absence or mitigation of transmission market power, a transmission-owning public utility seeking to sell at market-based rates must have on file with the Commission an open access transmission tariff for the provision of comparable service.").

customers is not applicable here.[140] Furthermore, upon Applicants' withdrawal from the Midwest ISO, they will continue to be subject to the KPSC's jurisdiction with respect to retail gas and electric rates, service, and operation. Accordingly, Applicants' withdrawal from the Midwest ISO will have no adverse effect on state regulation.[141]

VI. EFFECT ON RELIABILITY

Applicants' proposal will not have any adverse effect on reliability. First, as explained above, TVA will be the NERC-certified Reliability Coordinator for the Applicants' control area. As explained herein and in the testimony of Stuart L. Goza of TVA (Exhibit G hereto), TVA will satisfy all of NERC's Version 0 Reliability Standards and adequately ensure the reliability of the Applicant's transmission system. TVA fulfills its Reliability Coordinator duties in a manner consistent with NERC Standards, industry practices and business processes.[142] As a Reliability Coordinator, TVA has been audited by NERC and SERC and received high marks for meeting Reliability Coordinator requirements.[143] In its role as Reliability Coordinator, TVA has maintained regional reliability and consistently met all SERC and NERC compliance measures. TVA operates two completely separate systems that perform state estimation and contingency analysis.[144] Both systems are independently operated and have dual-redundant computer systems located in and immediately available at separate TVA control centers. Models used in both systems are built weekly using equivalent external area models derived from VAST operating cases maintained intra-monthly for configuration and facility changes within the region.[145]

Second, TVA clearly has the expertise and proven track record to serve as Applicants' Reliability Coordinator. As an Reliability Coordinator, TVA operates one of the largest and most reliable transmission systems in North America and is responsible for monitoring and ensuring the reliable operation of the bulk transmission system in an 10-state region that includes Tennessee, and portions of Alabama, Georgia, Illinois, Iowa, Kentucky, Mississippi, Missouri,

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140 *See* Order No. 642, FERC Stats. & Regs. at 31,914-15.

141 *See Madison Gas and Elec. Co.*, 106 FERC ¶ 61,098, P 20 (2004); *Texas-New Mexico Power Co., Southern New Mexico Elec. Co.*, 105 FERC ¶ 61,028, P 22 (2003); *Ameren Energy Generating Co., Union Elec. Co., d/b/a AmerenUE*, 103 FERC ¶ 61,128, P 60 (2003).

142 Goza Testimony at 8.

143 *Id.*

144 *Id.* at 14.

145 *Id.*

North Carolina, and Virginia.[146] TVA has maintained 99.999 percent reliability over the past five years in delivering electricity to customers.[147] During the 2005 summer, TVA surpassed its all-time peak demand of 29,966 MW with a peak demand of 31,703 MW on July 25, 2005 and demand of 31,935 MW the following day. These demands were met with no customer interruptions while also handling power from other areas moving across the TVA system. TVA demand exceeded 29,000 MW for eight consecutive days beginning July 20, 2005 with no customer interruptions.[148]

Mr. Goza lists several recent TVA accomplishments in maintaining reliability.[149] For example, TVA has received two *Examples of Excellence* from NERC, has successfully transitioned to the NERC Functional Model framework, and has implemented the new NERC Reliability Standards updating all our processes and procedures to align with revised and emerging industry rules.[150] Also, TVA has enhanced its operating system and implemented cyber-security monitoring.[151]

Third, as explained above, TVA is also uniquely suited to serve as the Reliability Coordinator for Applicants' transmission system. TVA already has an existing relationship with Kentucky, *i.e.*, as Reliability Coordinator for EKPC and BREC. As demonstrated by the TVA Reliability Area Maps (Exhibit I hereto), Applicants' footprint is already embedded within TVA's reliability area. The maps demonstrate that TVA is a natural and logical choice to oversee reliability coordination for the Applicants' system.

Fourth, TVA's oversight and planning authority of Applicants' transmission system will facilitate additional interconnects between Applicants' system and TVA, and create opportunities for transmission expansion (which will in turn will increase regional reliability). Although the Midwest ISO, as a NERC-certified Reliability Coordinator, would also abide by NERC Version 0 Reliability Standards, TVA will not have to focus on such a wide geographic area and will instead be able to make reliability decisions that would make sense for the smaller footprint, which already encompasses most of Kentucky. Essentially, it will be easier for TVA to maintain reliability in the smaller, less complicated footprint.

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[146] *Id.* at 4.

[147] *Id.* at 8.

[148] *Id.* at 3.

[149] *Id.* at 8-10.

[150] *Id.* at 8.

[151] *Id.* at 10.

VII. INFORMATION REQUIRED UNDER 18 C.F.R. PART 35

A. Action Date and Proposed Effective Date

Applicants request Commission action on this filing by February 1, 2006. This date is necessary to ensure that Applicants and the Midwest ISO may effectively coordinate the transition over to the ITO/Reliability Coordinator model prior to the 2006 summer season.

Applicants seek an effective date for the rates proposed herein as of the date the Commission accepts this submittal for filing. Applicants request waiver, to the extent necessary, of the Commission's 60-day or 120-day notice requirements (as may be applicable) in order to permit the rates to take effect upon the Commission's acceptance of this submittal for filing.[152]

B. Service

A copy of this transmittal letter and all exhibits has been served by First Class U.S. Mail (postage paid) on all of the affected state commissions, and on all customers affected by this filing, as well as the Midwest ISO. A list of all those to whom this transmittal letter and exhibits has been sent is attached hereto as Exhibit O.

C. Notice

A form of notice suitable for publication in the Federal Register is attached hereto as Exhibit P. In addition, an electronic version of the notice is included on the enclosed diskette.

D. Communications

Applicants request that all notices and correspondence related to this filing be sent to the following individuals, and that the Secretary include these individuals on the official service list for these proceedings.

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152 *See* 18 C.F.R. § 35.3 (2005).

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E. Additional Matters and General Waivers

Per 18 C.F.R. § 35.13(b)(7), Applicants state that no expenses or costs associated with their proposed rates have been alleged or judged in any administrative or judicial proceedings to be illegal, duplicative, or unnecessary costs that are demonstrably the product of discriminatory employment practices.

Applicants respectfully request a waiver of any requirements of 18 C.F.R.§ 35.13 that have not been fulfilled by this filing. The tariff sheets filed herein do not contemplate a change in rates other than what is necessary to effectuate Applicants' withdrawal from the Midwest ISO. Furthermore, as noted throughout this filing, the proposed rates have been approved by the Commission as *pro forma* rates, or reflect rate and tariff terms accepted by the Commission in other proceedings.

VIII. REQUEST FOR PRIVILEGED TREATMENT.

Applicants respectfully request privileged treatment, in accordance with 18 C.F.R. § 388.112, for certain of the workpapers of Dr. Hieronymus, as contained on one of the two enclosed CD-ROMs.[153] Applicants have labeled this confidential CD-ROM with the words "Contains Privileged Information – Do Not Release." Applicants consider the information on this CD-ROM to be "commercial…information obtained from a person [that is] privileged or confidential."[154]

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153 Additional, public workpapers are enclosed on the other CD-ROM.

154 *See* 18 C.F.R. § 388.107(d) (2005).

IX. CONCLUSION.

WHEREAS, as set forth above, Applicants respectfully request that the Commission approve their withdrawal from the Midwest ISO, accept the attached rates for filing, and find that the Applicants' proposal is consistent with the Merger Conditions, as discussed herein.

Respectfully submitted,

Clifford S. Sikora
Jeffrey M. Jakubiak
Andrea J. Chambers
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Date: October 7, 2005
Washington, D.C.

Exhibit A

(See Volume II)

Exhibit A-1

(See Volume III)

Exhibit B

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LG&E Energy LLC	**)**	**Docket No. ER06-___-000**
	)	
Louisville Gas & Electric Company, *et al*.	**)**	**Docket No. EC98-2-___**
	)	
Louisville Gas & Electric Company, *et al*.	**)**	**Docket No. EC00-67-___**
	)	
E.ON AG, *et al*.	**)**	**Docket No. EC01-115-___**

TESTIMONY OF PAUL W. THOMPSON

Q. Please state your name, position and business address.

A. My name is Paul W. Thompson. I am the Senior Vice President of Energy Services for LG&E Energy LLC ("LG&E Energy"), the parent company of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (LG&E and KU are collectively referred to as the "Companies"). My business address is 220 West Main Street, P.O. Box 32020, Louisville, Kentucky 40202.

Q. What is the purpose of your testimony?

A. I will provide a brief general overview of the Companies' application and the evidence that supports it. I will also present the Companies' reasons for becoming charter members of Midwest Independent Transmission System Operator, Inc. ("MISO"), and describe the reasons that the Companies now seek to exit, as well as why the Companies' exit will not harm MISO. As part of this application, the Companies are filing a new Open Access Transmission Tariff. I will provide the reason for that filing. The Companies also presented evidence in an ongoing proceeding before the Kentucky Public Service Commission ("Kentucky PSC") concerning the Companies' membership in the MISO. I will summarize that proceeding. Finally, I will affirm the Companies' commitment to maintaining credible independence and transparency in their control areas through the use of a stakeholder process.

Q. Please provide a brief overview of the Companies' proposal set out in its application and the evidence that supports it.

A. In view of the Federal Energy Regulatory Commission's ("Commission" or "FERC") goal of increasing confidence in the independence and transparency of the operation of the Companies' transmission system, the proposal contained in the Companies' application would not only effect the Companies' exit from MISO, but would also install both an Independent Transmission Organization to administer the Companies' new OATT and a new NERC-certified Reliability Coordinator ("RC"). The Companies have undertaken Request for Proposals processes ("RFPs") to identify the best candidates for these roles, and have selected the Southwest Power Pool ("SPP") and the Tennessee Valley Authority ("TVA") to fill the ITO and RC roles, respectively. These separate and independent entities will assume responsibility for those transmission-related functions and will fulfill the Commission's policy objectives.

As I and the Companies' other witnesses show through our testimony, the Companies' proposal addresses the market power issues that gave rise to the Companies' existing merger conditions and is consistent with the public interest, both at the state and national levels. In particular, the employment of an Independent Transmission Organization and a Reliability Coordinator ensures that the Companies will maintain the requisite level of independence in the operation of their transmission system and prevent any exercise of transmission market power while maintaining a high level of system reliability.

Furthermore, this proposal achieves the Commission's objectives for ensuring reliable, non-discriminatory, open access transmission service through the prudent use of sound business practices. The Companies have used a competitive bidding process to solicit bids from independent entities wishing to serve as the Reliability Coordinator and are currently in the process of completing a competitive bid process for the Independent Transmission Organization. The Companies' requests for proposals were designed to solicit bids from entities that meet the Commission's independence criteria, including existing RTOs and ISOs. Employing a competitive bidding process has ensured that the selected Independent Transmission Organization and Reliability Coordinator will ultimately provide efficient and cost-effective service.

The Companies are currently in negotiations with SPP regarding an ITO Agreement. To date, the ITO Agreement has not been executed, so the Companies submit a pro forma version of this agreement in Attachment M of the OATT. Under that agreement, the Companies will remain the owners and operators of their transmission system (as they are today), and will continue to maintain ultimate responsibility for the provision of transmission service, including the sole authority to amend their OATT pursuant to Section 205 of the Federal Power Act. However, the Independent Transmission Organization would assume responsibility for a number of core transmission functions, including OATT administration, approval of all transmission service requests, oversight of system impact studies and facilities study agreements, OASIS administration, calculation of total transfer capability and available transmission capacity, transmission scheduling, generation interconnections, and administration of a stakeholder process. Each of the functions that will be assigned to the Independent

Transmission Organization meets, or exceeds, the level of responsibility that the Commission has found to facilitate competition through transmission independence.

In addition, the Companies have negotiated an agreement with TVA and coordinated with TVA to institute TVA as their North American Electric Reliability Council ("NERC")-certified Reliability Coordinator. This Reliability Coordinator will provide: (i) security coordination (as defined in relevant NERC Version 0 standards); (ii) transmission planning and regional coordination; and (iii) administration of any seams agreements (although this function may also be provided by the Companies).

The Companies are committed to maintaining clear independence and transparency in their control area, and believe their proposal should further these objectives.

In support of its filing, the Companies submit the testimony of several witnesses. First, Dr. William Hieronymus demonstrates that the proposal mitigates any potential market power concerns at least as adequately as the RTO membership condition to which the Companies voluntarily agreed in the LG&E-KU merger. Dr. Hieronymus testifies that the Companies' proposal substantively complies their previous merger commitments (Exhibit B). Second, Ms. Vicky Bailey, a former member of the Commission, explains why approval of this filing promotes sound regulatory policy (Exhibit C). Third, Mr. Mathew Morey, Senior Consultant, Laurits R. Christensen Associates Inc., explains how the Companies' proposed ITO/RC is economically superior to, and hence more prudent than, the Companies' continuing MISO membership (Exhibit D). Fourth, Mr. Mark Johnson, Director of Transmission, LG&E Energy, LLC ("LG&E Energy") describes the functions of the Independent Transmission Organization and Reliability Coordinator and the RFP process that led to their selection (Exhibit E). Fifth and finally, Pat O'Connor of TVA testifies as to TVA's qualifications and ability to serve as the Companies' reliability coordinator.

Q. What were the reasons that the Companies became charter members of MISO?

A. The Companies had two primary goals in helping to form and initially joining MISO as it was originally conceived: (i) to comport with emerging federal regulations, such as Order No. 888 (and subsequently Order No. 2000); and (ii) to achieve greater transmission system reliability. At the time the Companies became charter members of MISO they believed that MISO's structure and function would help further their functions as low-cost, vertically integrated utilities because MISO's purposes were limited to providing non-discriminatory open access transmission service over the transmission assets entrusted to its operational control, as well as receiving and distributing funds for the use of those assets as agent for the MISO Transmission Owners. The Companies' belief that MISO could help the Companies' continue their low-cost provision of service to native load also made MISO participation seem prudent from a state regulatory perspective.

Q. Why do the Companies now seek to exit MISO?

A. The Companies seek exit from MISO because their analyses during the recent Kentucky Public Service Commission investigation concerning the Companies' MISO membership show that, despite effectively mitigating vertical market power, MISO membership has become a less prudent and more controversial means of meeting the goals of open access transmission and otherwise complying with federal policy than would be other available alternatives recently approved by FERC.

Two other important considerations further support the Companies' exit from MISO. First, the Companies can obtain equivalent reliability coordination services from other providers, as all reliability coordinators must be NERC-certified. Moreover, the Commission has proposed that such organizations will be governed by an Electric Reliability Organization pursuant to the Commission's new authority in Title XII, Subtitle A, Section 1211(a) of the Energy Policy Act of 2005, further ensuring equivalence of reliability coordination services. Second, MISO's Day 2 markets represent a significant departure from the traditional regulatory regime that Kentucky has chosen to continue implementing; a departure more beneficial and accommodating to utilities in states that have opted to unbundle services or adopt retail choice.

Kentucky is not a retail choice state, having elected to maintain its long-standing structure of vertically integrated, rate-regulated utilities like the Companies, the primary objective of which is to serve native load at the lowest reasonable cost using Companies-owned and -controlled, coal-fired generation. This venerable approach, under which the Companies historically have served approximately 99% of native load with their own low-cost generation,[1] has served Kentucky well, having assured consumers access to low-cost power.

For these reasons, and having carefully reviewed MISO's evidence throughout the Kentucky PSC MISO case, the Companies determined that withdrawal from MISO would be in the Companies' best interests, as well as the public interest, because the evidence indicated that MISO membership is no longer the most prudent means of

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[1] *In the Matter of: Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission Operator, Inc.*, Kentucky Public Service Commission Case No. 2003-00266, Supplemental Testimony of Martyn Gallus at 8, ll, 14-16 (9/29/04).

meeting federal regulatory open access requirements and the Companies' merger commitments.

For these reasons, on December 28, 2004, the Companies formally notified MISO in writing of their intent to withdraw from the MISO. Sending the notice before the end of the calendar year also served to prevent the Companies from having to pay an additional year of schedule fees. (Article Five, Section One provides that withdrawal cannot be effective until at least one full calendar year after December 31 of the year in which a MISO member gives its notice of intent to withdraw.) MISO has acknowledged that the Companies have given proper and effective notice and that, once the Companies receive the Commission's and the Kentucky PSC's permission to exit, the Companies may indeed exit MISO as early as January 1, 2006. As of the date of this filing, the Companies are engaged in negotiations with MISO over the appropriate exit fee. The Companies believe that an agreement will be reached on this matter relatively quickly. The Companies plan to amend this filing to update the Commission when a definitive exit agreement is reached.

Q. Please describe the Kentucky Public Service Commission's MISO-related proceedings in which the Companies have participated.

A. On July 23, 2003, Kentucky Public Service Commission initiated an investigation to determine if the Companies' continuing participation in MISO is in the public interest and asked the Companies and interveners to determine whether the Companies' continuing participation in MISO is cost-effective.

In the first phase of the Kentucky PSC's investigation, the Companies showed that exiting MISO in favor of obtaining reliability coordination services from another

NERC-certified reliability coordinator would be economically beneficial to the Companies and, therefore, their customers, even taking into account paying the MISO exit fee. Nonetheless, the Companies' analysis in this phase of the investigation also showed that, should the Companies be required to participate in an RTO for reliability purposes, MISO was more cost-effective than other RTOs under consideration at that time.

In the second phase of the investigation, which the Kentucky PSC initiated by order dated June 22, 2004, the Kentucky PSC instructed the Companies to perform further analysis that addressed the possibility of joining an RTO other than MISO, such as PJM or SPP, and the impact of MISO's Transmission Energy Market Tariff ("TEMT"). The Companies again conducted their analysis and determined that exiting MISO in favor of procuring the services of a NERC-certified reliability coordinator was economically preferable to continued MISO membership in Day 2, again even in view of paying a MISO exit fee. Unlike the first phase of the Kentucky PSC investigation, however, in this phase, in which Day 2 had greater definition, the Companies' analysis showed that MISO is no longer the most cost-effective RTO: if the Companies must be in an RTO, SPP is economically preferable to MISO (although PJM is not).

Q. Should the Commission be concerned that the Companies' exit from MISO will have a negative effect on MISO's Day 2 markets?

A. No. The August 19, 2004 Louisville Courier-Journal quoted MISO's President and CEO, James Torgerson, as saying that the Companies' withdrawal from MISO would have only "a minor impact" on the Day 2 markets. More recently, in the Kentucky PSC proceeding, MISO's chief witness, Dr. Ronald R. McNamara, stated that MISO has no serious concern that other MISO members will follow the Companies' lead if the Commission and the Kentucky PSC allow the Companies to exit in accord with the Companies' current proposal. Thus, at least in MISO's view, allowing the Companies to exit MISO will not materially alter or affect the ISO's markets and operations.

Furthermore, should the Commission approve the Companies' exit from MISO, the Commission can be assured that MISO and its remaining members will be made whole for any obligation incurred on the Companies' behalf because the Companies will pay the exit fee appropriate for withdrawal from MISO under Article V, Section II of the MISO Transmission Owners Agreement ("TO Agreement"). The same section also requires that the Companies hold harmless those users taking transmission service from the Companies pursuant to contracts executed prior to December 28, 2004, the date the Companies gave MISO notice of their intent to withdraw. That same section of the MISO TO Agreement also requires the Companies and MISO to renegotiate the Companies' construction obligations and any other obligations created by the TO Agreement, which should result in a satisfactory solution that will do MISO and its members no harm.

In addition to the requirements set out in the TO Agreement, MISO's Chief Executive Officer, James Torgerson, and I met on September 9, 2005, to discuss the Companies' costs of exit, including the MISO exit fee. Mr. Torgerson and I also discussed the other topics I mentioned above, including holding users of the Companies' transmission system harmless from costs associated with the Companies' exit from MISO.

Q. Why are the Companies filing a new Open Access Transmission Tariff as part of this application?

A. The Companies are filing a new Open Access Transmission Tariff ("OATT"), FERC Electric Tariff Volume No. 1, in order to satisfy the Commission's standards for reliable, non-discriminatory, open access transmission service, as articulated in Order Nos. 888, 889 and 2000. Specifically, the Companies' new OATT provides that key transmission functions will be administered by the Independent Transmission Organization. The Companies respectfully request that the Commission accept as just and reasonable this OATT and its attachments. The OATT substantially follows the Commission's pro forma OATT. The transmission rates are the same rates which MISO charges transmission customers today under the so-called Attachment O formula rate. The Companies adopt that formula in this filing, therefore no rate levels will change. In addition, all other terms and conditions included in the OATT – with the exception of Attachments L and M which implement the Independent Transmission Organization and Reliability Coordinator – are standard provisions or have been accepted for filing by the Commission in other dockets.

Q. Specifically, what relief do the Companies request from the Commission?

A. The Companies respectfully request that the Commission:

1. Accept for filing certain rates, terms and conditions necessary for the Companies to:

   a. Withdraw from MISO and regain operational control of the Companies' transmission system;

   b. Install a third party certified by NERC to act as reliability coordinator for the Companies' transmission facilities subject to the jurisdiction of the Commission;

c. Install an independent third party to act as tariff administrator for the Companies' transmission system (an "Independent Transmission Organization" or "ITO"); and

2. Find under FPA Section 203 that the Companies' withdrawal from MISO, together with the operation and administration of the Companies' transmission system by the ITO and reliability coordinator is consistent with the Applicants' merger conditions.

Q. Does the Company need any other regulatory approvals before its withdrawal from MISO can become fully effective?

A. Yes. The Companies ask the Commission to note that the Companies cannot withdraw from MISO, even with this Commission's approval, unless and until the Kentucky PSC also grants the Companies permission to transfer operational control of their transmission assets from MISO to the new Reliability Coordinator. Because the Kentucky PSC cannot act until a definite alternative to MISO is presented to it, the Companies ask the Commission to act with all possible speed in approving the Companies' proposal, i.e., by February 1, 2006. The Commission's prompt action will enable the Companies to complete their regulatory and operational withdrawal from MISO by their target date, before the summer of 2006.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, Paul W. Thompson, being duly sworn, deposes and says he is the Senior Vice President of Energy Services for LG&E Energy LLC, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

PAUL W. THOMPSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 6th day of October 2005.

Notary Public

My Commission Expires:

Notary Public, Cobb County, Georgia
My Commission Expires September 10, 2008

Exhibit C

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LG&E Energy LLC	)	**Docket No. ER06-___-000**
	)	
Louisville Gas & Electric Company, *et al*.	)	**Docket No. EC98-2-___**
	)	
Louisville Gas & Electric Company, *et al*.	)	**Docket No. EC00-67-___**
	)	
E.ON AG, *et al*.	)	**Docket No. EC01-115-___**

TESTIMONY OF MATHEW J. MOREY

Q. Please state your name, current position, and business address.

A. My name is Mathew J. Morey. I am Senior Consultant with Christensen Associates Energy Consulting LLC. My business address is 409 Cambridge Road, Alexandria, Virginia. Christensen Associates Energy Consulting's principal business address is 4610 University Avenue, Suite 700, Madison, Wisconsin.

Q. Please describe your education, professional background, and qualifications.

A. I received my doctorate in economics and statistics from the University of Illinois in 1977, and taught economics and econometrics for nearly twenty years. During that time, I also worked as a consultant to companies in and regulators of the telephone, natural gas, and electricity industries. I worked as Director of Economics at the Edison Electric Institute from 1996 to 2000. Prior to joining Christensen Associates in 2003, I worked as an independent consultant to companies in the electricity industry both in the U.S. and Canada.

Q. Have you previously testified before regulatory utility commissions?

A. Yes. I have testified before state and federal regulatory agencies, as well as state legislative bodies, on a wide range of electric industry restructuring issues including stranded costs, market power, seams elimination cost adjustment charges, utility codes of conduct, utility-affiliate transfer pricing rules, distribution standby and transmission rate design, and the costs and benefits of membership in Regional Transmission Organizations ("RTOs"). A complete list of my appearances is contained in my résumé appended hereto.

Q. Have you previously testified before the Federal Energy Regulatory Commission?

A. Yes, I testified in Docket No. ER03-262-000 on various aspects of the Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") methodology and charges. I have also testified before the Commission in Docket No. RM04-7-000 on the issues of the Commission's interim market power screens in conjunction with applications for market-based rate authority.

Q. What is the purpose of your testimony?

A. My testimony supports the application of Louisville Gas and Electric Company and Kentucky Utilities Company (the "Companies") to end their membership in the Midwest Independent Transmission System Operator ("MISO") and to instead establish an arrangement with an independent Reliability Coordinator ("RC") and an Independent Transmission Organization ("ITO") that will satisfy the Commission's objectives expressed in Order Nos. 888 and 889 and the Companies' merger commitments. The Companies believe – as do I – that these objectives can best be satisfied through an RC/ITO arrangement rather than through membership in MISO.

Q. Please summarize your findings.

A. Order Nos. 888 and 889 have the goal of facilitating competition in generation services. In furtherance of this goal, they require that transmission owners offer non-discriminatory transmission access. RTO membership is one important avenue for implementing non-discriminatory transmission access; but it is not the only possible avenue. In particular, an RC/ITO arrangement can also satisfy the objectives of Order Nos. 888 and 889 and, in some instances, can do so at lower cost and with greater net benefits to consumers. In the Companies' case, the RC/ITO potentially could save its customers between $8 million and $13 million per year.

The RC/ITO proposal as a means to fulfill Order No. 888 objectives is reasonable for the Companies and their customers because the benefits of membership in an RTO such as MISO – lower power procurement costs and increased off-system sales and margins – are small compared to the costs of membership. The Companies' RC/ITO proposal introduces a degree of flexibility into the division of functions necessary to satisfy Order No. 888 requirements and functions necessary to ensure grid reliability. The RC/ITO concept satisfies Order No. 888 requirements at lower cost than does RTO membership, leaves the Companies in control of their transmission and generation assets, maintains state regulatory authority and control over retail rates and costs, and gives the Commission a policy option that can advance Order No. 888 objectives with potentially less controversy than has attended the Commission's pursuit of Order No. 2000 and "full-service" RTOs.

Q. How is your testimony organized?

A. Section I summarizes the Order Nos. 888 and 889 requirements that transmission owners, including the Companies, are required to meet. Sections II through IV explain why RTO membership is not needed to achieve the objectives of these orders, why an RC/ITO can be an appropriate alternative vehicle for achieving these objectives, and how the RC/ITO approach offers a promising means of strengthening RTOs' incentives for cost and quality control relative to the standard RTO approach.

Section V explains that the Companies' share of MISO's costs have turned out to be higher than the Companies originally anticipated and higher than they have recently projected. Section VI demonstrates that an RC/ITO can achieve Order No. 888 objectives at lower cost to the Companies' consumers than can MISO membership. Section VII describes the Companies' plan for developing an RC/ITO arrangement in accordance with the requirements of Order Nos. 888 and 889. Finally, Section VIII summarizes the reasons that the Commission should approve the Companies' plan to develop an RC/ITO.

I. TRANSMISSION OWNERS, INCLUDING THE COMPANIES, ARE REQUIRED TO MEET THE OBJECTIVES OF ORDER NOS. 888 AND 889

Q. What are the objectives of Order Nos. 888 and 889?

A. The Commission stated in Order No. 888 that its "goal is to ensure that [electricity] customers have the benefits of competitively priced generation."[1] The Commission further stated that "[n]on-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition."[2] Thus, to achieve that goal, the Commission required transmission-owning public utilities to provide non-discriminatory (open) access to their grids and file *pro forma* open-access transmission tariffs that would facilitate that access. To further strengthen the non-discriminatory access provisions of

1 Order No. 888, FERC Stats. & Regs. at 31,652.

2 *Id.*

Order No. 888, the Commission issued the companion Order No. 889 that requires public utilities to make information about transmission service and capacity availability transparent to transmission customers through the creation of Open Access Same-Time Information Systems ("OASIS").

Order No. 888 also encourages public utilities to cooperate voluntarily to form Independent System Operators ("ISOs") that:

- Operate independently of all market participants,
- Provide open access to the transmission system,
- Administer a single region-wide tariff that eliminates rate pancaking,
- Maintain the reliability of the transmission grid, and
- Control the operation of all of the transmission facilities within the region.

The objective of ISO creation was to ensure that transmission service is provided on a non-discriminatory basis; that the terms, conditions, and rates for transmission service are transparent; and that barriers to trade, particularly payment of multiple transmission rates for wheeling power over long distances ("rate pancaking"), are reduced or eliminated. The ultimate objective of ISO creation was the promotion of greater competition among generators in wholesale power markets, which was expected to put downward pressure on electricity production costs and prices. Competition was thus expected to produce efficiency gains that would deliver benefits to all consumers in the form of lower overall costs of delivered power.

Q. Is it important to achieve the goals of Order No. 888 in a cost effective manner?

A. Yes. Order No. 888's goals should be achieved so as to bring the highest net benefits to consumers, which generally means that costs should be kept to a minimum. Inevitably, there will be transaction costs in implementing reforms as far reaching as those embedded in Order No. 888. If implemented poorly, these costs can offset – and even exceed – both the short-term and long-term gross benefits of the Order. A fundamental policy objective should therefore be to find low-cost means of implementing Order No. 888.

II. RTO MEMBERSHIP IS NOT NEEDED TO ACHIEVE THE OBJECTIVES OF ORDER NOS. 888 AND 889

Q. Is there evidence that RTO membership may not always be the most effective means of achieving the objectives of Order Nos. 888 and 889?

A. Yes. The total value of the several benefits arising from open access facilitated by an RTO with centralized control of the transmission system is not necessarily greater than the cost of creating that institution and reorganizing functional responsibilities between an RTO and public utility transmission owners. The evidence on this point, even today in 2005, is mixed. The benefits of RTOs are more likely to exceed their costs for those ISOs that were created from the tight power pools in the Northeastern U.S. – namely ISO New England, the New York ISO, and the PJM Interconnection LLC ("PJM") – although this is not a certainty. In these particular cases, startup costs have been kept to reasonable levels because much of the necessary infrastructure already existed. Even in these cases, the costs to create the institutional infrastructure to support the wide array of Order No. 888 functional services that these Northeastern RTOs provide may well offset the short-term gross benefits – the evidence is not clear on this point. For ISOs that were created from scratch, however, the startup costs have been higher. Any net benefits for consumers have a far greater probability of being lower, and are far more likely to be negative. Thus, for some regions, at least, the potential aggregate costs of RTO creation may well exceed the benefits, at least in the short term.

Q. How are the foregoing cost considerations relevant to the Companies' present situation?

A. In Kentucky, policy makers have chosen to retain the vertically integrated utility model. They have done so because it has worked very well in an absolute and relative sense compared to what has taken place in other parts of the country. Consumers of the Companies have paid and continue to pay some of the lowest prices for delivered power of any consumers in the country. Figure 1 illustrates this point well by comparing average revenue for all customer classes for several Midwestern states over the period 1996 to 2003.[3] The Companies' customers have paid on average less than 4.5 cents per kWh over this period, <u>averaging 21 percent less than average revenues in Indiana, the second lowest priced Midwestern state</u>.

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[3] These data are from the U.S. Energy Information Administration. *See* <http://www.eia.doe.gov/cneaf/electricity/esr/esr_tabs.html, average_price_state.xls> (accessed August 29, 2005).

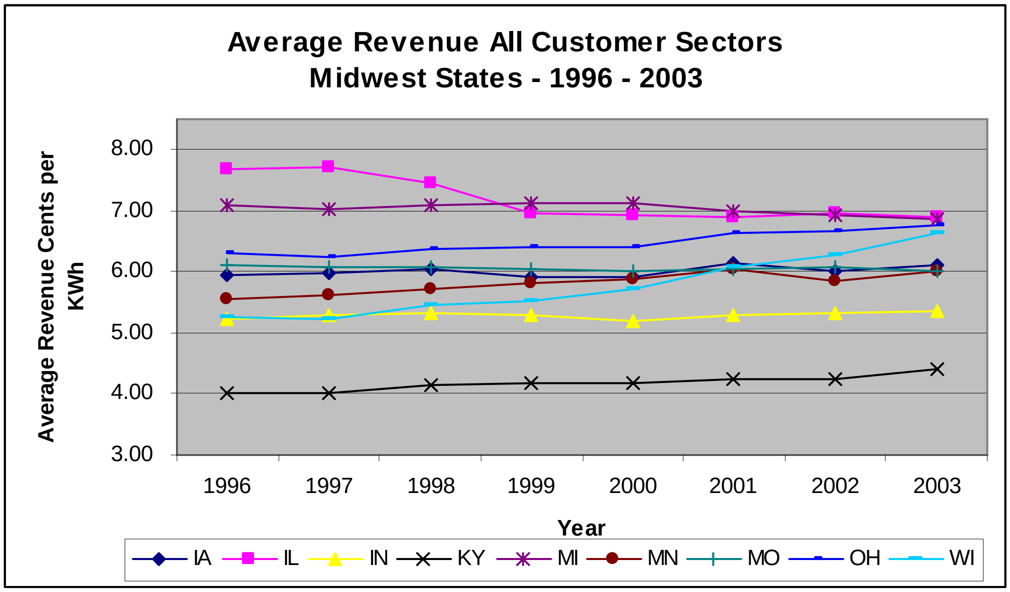

Figure 1 Average Revenue - All Customers Sectors, Midwest States, 1996 - 2003

When average revenues in Kentucky are compared to the rest of the U.S. over this same period, the relative success of the vertically integrated utility model in Kentucky is even more striking, as illustrated in Figure 2.

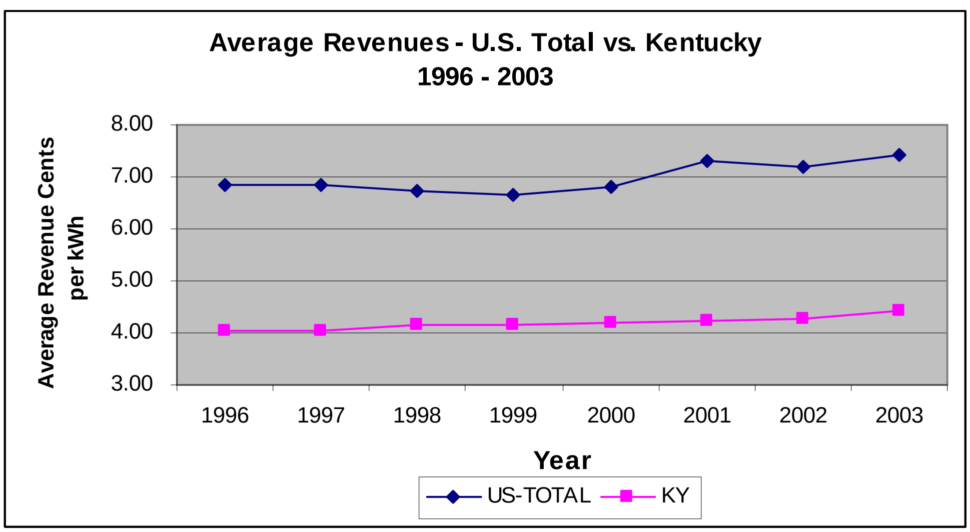

Figure 2 Average Revenues - U.S. Total vs. Kentucky, 1996 - 2003

Q. Relative to RTO membership, is there a cheaper alternative vehicle for achieving the objectives of Order Nos. 888 and 889?

A. I believe that, for some transmission owners such as the Companies, the answer is clearly "yes." This cheaper alternative is embodied in the RC/ITO approach proposed by the Companies in this filing and as described below.

III. AN RC/ITO CAN BE AN APPROPRIATE VEHICLE FOR ACHIEVING THE OBJECTIVES OF ORDER NOS. 888 AND 889

Q. How has the institutional landscape changed since the Commission issued Order No. 888?

A. When the Commission issued Order No. 888 in 1996, the institutional choices for delegating responsibility for both transmission system operations and reliability coordination were narrower than they appear to be today. In 1996, there were tight power pools in the northeastern U.S. that could readily assume responsibility for system operations, generation dispatch, and reliability coordination because they were already performing some of those functions at that time. There were no such institutions in the rest of the country that could immediately perform Order No. 888 functions independently of the public utilities that owned and operated transmission systems and the majority of generation assets. Today, transmission owners can satisfy Order No. 888's technical requirements by contracting out responsibility for grid operations and tariff administration functions to an existing Commission-approved RTO that assumes the role of the RC/ITO. Alternatively, a new RC/ITO can be created to assume responsibility for performing Order No. 888 functions.

Public Utilities have contracted out Reliability Coordination services for many years and continue to obtain these services through contract. Hence, this dimension of the RC/ITO concept is not an innovation. The Companies can enter into a contract with one of several NERC-certified Reliability Coordinators in proximity to the Companies' control area. The reliability of the transmission system will be maintained and the costs of doing so can be kept to a minimum. This is discussed in more detail by the Companies' witness Mark S. Johnson. The Companies have chosen TVA as their reliability coordinator through an RFP process. In accordance with my description above, TVA currently provides reliability coordination service for public power customers in Kentucky with widely dispersed loads throughout the Companies' service territory. TVA is well suited to provide such service to the Companies.

Q. How can an ITO satisfy Order No. 888 objectives?

A. An ITO can achieve Order No. 888 objectives by assuming responsibility for a number of core transmission functions, including but not necessarily limited to:

- Evaluation and approval of all transmission requests,
- Calculation of Total Transfer Capacity ("TTC") and Available Transfer Capacity ("ATC"),
- Operation and maintenance of the Companies' OASIS,
- Evaluation, processing, and approval of all generation interconnection requests, and performance of all related interconnection studies, and
- Coordination of transmission planning with entities in the wider region.

Q. Will these assigned functions meet the level of responsibility that the Commission seeks in Order No. 888?

A. Yes. Each of the functions that will be assigned to the ITO includes or exceeds the level of responsibility that the Commission has held will facilitate competition through transmission operator independence. As the Commission recognized in its order in

Entergy Services lnc., successful ITO proposals must "clearly and unambiguously give the [ICT] authority to grant or deny requests for transmission service [including any] feasibility studies, system impact analyses, or other studies necessary to evaluate a request for transmission service."[4] ITOs must also have "authority to independently administer [the transmission provider's] OASIS."[5]

Q. Under the ITO model concept, and specifically the ITO proposed by the Companies, will customers be assured of receiving non-discriminatory access to transmission owners' transmission systems?

A. Yes. Like the Entergy ICT concept approved by the Commission, the Companies' ITO should ensure that the Companies' OATT is administered in a non-discriminatory fashion. The ITO will oversee all transmission service requests, will compute ATC and TTC (or available flowgate capacity), and will oversee generator interconnection requests and studies. The ITO can do this as an entity that is, by design, structurally independent of all market participants. If the ITO is one of the Commission-approved RTOs, independence is, of course, a foregone conclusion. Such an ITO can ensure that market participants who use a transmission owner's transmission system can continue to place great confidence in the independence and transparency of the operation of the system and in the administration of its OATT, just as they would have been able to do if the system was under the direct functional control of an RTO.

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4 110 FERC ¶ 61,295 at P 67 (2005) ("Entergy Order"). The Companies' RC/ITO proposal splits the reliability coordination and independent tariff administration functions into two parts, following the NERC functional model. However, I believe the same principles would apply to the Commission's analysis of the RC/ITO as would apply to the Commission's analysis of the Entergy ICT.

5 *Id.*

Q. Can the ITO satisfy the Commission's desire to see barriers to competition removed, such as pancaked transmission rates?

A. Yes. To comply with the Commission's desire to see barriers to competition removed, an ITO can administer a transmission owner's OATT in a manner that promotes the elimination of pancaked rates. For a transmission owner in the Midwest, this would continue the policy of dispensing with the through-and-out transmission rates on intra-MISO transactions, as required for MISO membership or as part of the Commission's orders in the Seams Elimination Charge/Cost Adjustment/Assignment ("SECA") case.[6] The Companies' proposal contains a rate de-pancaking provision as part of its proposal. I believe this is an important feature which satisfies the Commission's Order No. 888 open access goal in this regard. De-pancaking goes even further by meeting the Commission's Order No. 2000 objectives of eliminating pancaked rates and fostering regional markets.

Q. Why can an ITO be a better way for some utilities to fulfill Order No. 888 objectives than membership in a "Day 2" RTO?

A. There are two main reasons for this fact. First, under some circumstances, an ITO can achieve Order No. 888 objectives at lower cost than can RTO membership. Second, under some circumstances, an ITO can impose on consumers a better profile of financial risks than is imposed by RTO membership. I discuss the cost issues at length later in my testimony. At this point, I wish to discuss the financial risk issues.

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[6] *See Midwest Indep. Transmission Sys. Operator, Inc.*, 109 FERC ¶ 61,168 (2004) ("November 2004 Order").

Q. Please explain the financial risks that electricity consumers face and how the electricity industry can be organized to deal with these risks.

A. Generation and transmission investments require significant capital outlays. Due to the magnitude of these outlays, the investments are inherently risky. In short, such capital intensive infrastructure investments are necessary for reliable delivery of a critical commodity (electricity), but future demand for use of the network is uncertain. For example, there could be unexpected changes in loads and fuel prices that can substantially change the net benefits of any investment. Traditionally, vertically integrated utilities made these investments with the understanding that cost-of-service retail rates would cover the return "of and on" capital, as well as operating costs. For the most part, regardless of whether the investments turned out to be bad or good, their costs were recovered from consumers through long-term amortization that smoothed consumers' rates over time. This had the advantage of providing consumers with rate stability and certainty, and it had the further advantage of allowing least-cost integrated planning of generation and transmission investments. On the other hand, the traditional model has sometimes had the disadvantage of providing utility management with poor cost-control incentives, thereby saddling consumers with the costs of bad utility decisions.

Competition and structural unbundling of generation and transmission services have the advantages of providing generation firms with strong incentives to control costs and of making generation firms responsible for the costs of their own mistakes. On the other hand, competition and structural unbundling have had three serious problems for which no fully satisfactory solution has been found. First, market prices can be very uncertain, both from one year to the next as well as from one hour to the next. This potentially (and sometimes actually) exposes retail customers to substantial market price risk that, as a political matter, has not been sustainable. This price risk, together with concerns over the exercise of generator market power, has resulted in the institution of price caps in RTO-administered markets that are specifically designed to prevent the market from working under conditions of generation capacity scarcity.

Second, competition and structural unbundling has arguably resulted in inadequate investment in generation and transmission facilities, which exacerbates the financial risks in the wholesale market. This is partly the result of the economic uncertainties that affect numerous capital-intensive industries; but it is also the result of continuing long-term regulatory uncertainty that is particular to the electric power industry. The RTOs in California, New England, and PJM are bemoaning the generation inadequacies that they face in certain subregions of their territories and, so, the RTOs in California and the Northeastern U.S. have all proposed and/or implemented installed capacity requirements that use non-market, administratively determined mechanisms to guide generation investment.

Third, competition and structural unbundling has made it difficult for generation and transmission to be planned jointly on a least-cost basis. An RTO's transmission planning function is supposed to overcome this difficulty; but the evidence thus far indicates that the system optimization that was arguably achieved under the vertically integrated utility model is at the present greatly diminished within the new model involving RTOs at the center of regional planning. This gap between hope and reality reduces the efficiency benefits that RTOs can deliver.

Q. How can an ITO help manage financial risks while providing the benefits of competition?

A. An ITO provides a mechanism for retaining the benefits of the vertically integrated utility model (rate stability and least-cost integrated planning of generation and transmission investments) while also gaining the market benefits of open access wholesale competition (and the assurance to market participants that transmission will be run by an independent party). It allows low-cost vertically integrated utilities to continue the planning and operating activities that have made them low-cost; it provides the non-discriminatory transmission access that is essential to wholesale competition; and it keeps the costs of transmission and coordination services low. In addition, the Companies' filing gives TVA the authority to oversee regional planning. This makes sense from a market and reliability perspective considering TVA's current reliability footprint in Kentucky.

Q. What criteria determine a region's or a state's choice between the vertically integrated industry structure and the vertically unbundled structure?

A. In principle, and more or less in fact, the choice should be and has been determined by how well or how badly the traditional vertically integrated industry structure has served each region and state relative to both the rest of the country and an economic ideal that can serve as a goal. Where retail prices have been high relative to the rest of the country, as in California and the Northeast, states and regions have generally opted to experiment with more unbundled structures. Where retail prices have been low relative to the rest of the country, as in Kentucky, states and regions have generally opted to "keep a good thing going," and to retain largely the existing industry structure.

Q. How are the relative virtues of an RC/ITO and RTO membership dependent upon industry structure?

A. In a vertically unbundled electricity industry, where there are numerous buyers and sellers at the wholesale and the retail level, it is technically necessary for an independent entity like an RTO to provide a full array of centralized services, including not only control of the transmission system but also security-constrained economic dispatch of generation. In theory at least, it may also make economic sense for the RTO to introduce locational prices to promote more efficient use of the transmission capacity and to send signals to buyers and sellers about the locational value of generation and transmission investments. Whether a locational pricing market model makes sense depends on whether the costs to implement and administer such a system will be lower than the gross benefits of such a system.

The imposition of the new market model offers small benefits, however, for the retail consumers of a vertically integrated utility in a state that has not unbundled retail service and that has relatively low retail rates. Indeed, such a market model exposes the utility and its customers to the kinds of risks that the vertically integrated model had already addressed successfully. In effect, the imposition of the new industry model on the low-cost utility and its customers in a bundled retail environment forces a "virtual structural separation" of generation and wires assets, at least in terms of financial settlements, that re-introduces financial risks that were previously managed through vertical integration.

Not all utilities that continue to be vertically integrated in bundled retail states need the full panoply of services that are offered – or imposed – by an RTO on its members to satisfy Order No. 888 requirements or to provide benefits of competition among generation in the wholesale market. As I have stated, for some public utilities – the Companies for example – the benefits to customers from full membership do not outweigh the costs. For the customers of such utilities, a less expensive RC/ITO arrangement can provide the benefits of competition without all the costs of an RTO membership.

The RC/ITO concept introduces choice among the services offered by RTOs. It is a pro-competitive policy option for the Commission to pursue vigorously in various parts of the country where the RTO cost-benefit analysis suggests that full membership is not economically justified.

IV. THE RC/ITO CONCEPT OFFERS A PROMISING MEANS OF STRENGTHENING RTOS' INCENTIVES FOR COST AND QUALITY CONTROL

Q. Does it make economic sense for existing RTOs, such as SPP or MISO, to offer to perform unbundled Order No. 888 functions for non-member utilities?

A. Yes. Existing RTOs should welcome the opportunity to unbundle their services and offer to perform Order No. 888 functions for non-member utilities. In fact, SPP has responded to the Companies' RFP for ITO services and will be providing such services to the Companies on an unbundled basis. Offering to perform Order No. 888 functions to non-member utilities would be one way in which an RTO could leverage economies of scale and scope in their operations. It would enable the RTO to recover from non-member utilities a portion of the fixed costs associated with RTO startup as well as recover some variable costs, thereby reducing the share of costs borne by RTO member utilities.

Q. In introducing competition in the market for coordination services, does the RC/ITO concept advance the objectives of Order No. 888?

A. Yes. The primary objective of Order No. 888 is to increase the net benefits that electricity provides to consumers. Competition, abetted by non-discriminatory transmission access, is the primary vehicle for achieving this objective. The RC/ITO concept is consistent with this objective because it introduces a degree of competition among RTOs (and perhaps other entities) to provide the coordination services that are needed to satisfy Order No. 888. The pressure of competition should help to keep the costs of obtaining these services down.

Furthermore, the RC/ITO concept provides new incentives for RTOs to maintain and improve the quality of their services. Because RC/ITO customers can only be attracted and maintained if these services are of suitable quality, RTOs will have financial incentives to achieve high quality standards. All "consumers" of RTO services – members as well as non-members – will benefit from RTOs responding to these incentives.

Entergy, Duke Power, MidAmerican and the Companies, by proposing to find and contract with RC/ITO-like entities to provide unbundled transmission and coordination services to fulfill Order No. 888 requirements, demonstrate that there is a developing market for such unbundled RTO services. The limited duration of the contracts, which would be a natural outcome of the desire of both parties to manage risk, would introduce a degree of contestability into the market for Order No. 888 services as well.

Q. In introducing competition in the market for coordination services, does the RC/ITO concept advance the objectives of other Commission proceedings?

A. Yes. As RTO costs have mounted over the past several years, RTO members as well as the Commission have become keenly interested in finding ways for RTOs to achieve greater cost accountability. Motivated by this rising tide of concern, the Commission issued a Notice of Inquiry ("NOI") regarding the transparency and accountability of RTO costs.[7] While the NOI explored the need for changes to accounting and financial reporting practices among RTOs and ISOs, it also highlighted the need for cost transparency and uniformity among the RTOs – not only with respect to accounting practices but also uniformity with respect to many Order No. 888 services they provide to their members. The Commission can take a significant step toward promoting both cost accountability and uniformity in RTO practices by continuing to encourage a RC/ITO type of arrangement for non-member public utilities.

V. MISO'S COSTS HAVE TURNED OUT TO BE HIGHER THAN THE COMPANIES ORIGINALLY ANTICIPATED

Q. What has happened that has caused the Companies to look for new ways to fulfill Order No. 888 objectives?

A. A significant factor in altering the Companies' position on ISOs as the vehicle for achieving Order No. 888 objectives was MISO's decision to move from performing Order No. 888 functions to performing optional Order No. 2000 functions that include administering day-ahead and real-time energy spot markets that employ centralized security-constrained economic dispatch with LMPs as the basis for financial settlements. An ISO performing Order No. 888 functions has been characterized as a "Day 1" RTO,

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[7] *Financial Reporting and Cost Accounting, Oversight and Recovery Practices for Regional Transmission Organizations and Independent System Operators,* Notice of Inquiry, 108 FERC ¶ 61,237 (2004).

while an ISO performing Order No. 2000 functions has been called a "Day 2" RTO. A Day 2 RTO offers all of the services of the Day 1 RTO and, in addition: administers forward and real-time spot electricity markets; manages congestion through prices for use of congested transmission facilities that depend upon the differences in LMPs at resource and load locations; administers a financial transmission rights ("FTRs") market that enables market participants to partly hedge against uncertain congestion prices; provides ancillary services (like reserves); and (perhaps) administers a generation capacity market.

When the Companies examined the costs and benefits for themselves and their customers associated with the move in MISO from a Day 1 RTO to a Day 2 RTO, they estimated that there would be a net loss to their consumers in Kentucky relative to the Companies exiting MISO, and determined that pursuing a less costly arrangement that would still satisfy Order No. 888 objectives.

VI. AN RC/ITO CAN ACHIEVE ORDER NO. 888 OBJECTIVES AT LOWER COST TO THE COMPANIES' CONSUMERS THAN CAN MEMBERSHIP IN MISO

Q. What would be the cost savings from the Companies obtaining Order No. 888 services from an RC/ITO rather than from MISO?

A. I estimate that the cost for an RC/ITO to perform Order No. 888 functions should lie in the range of $4 million to $7 million per year. In contrast, a conservative estimate of the ultimate cost to the Companies' customers of membership in MISO and obligatory participation in the Day 2 markets MISO administers lies between $15 million and $17 million per year. A conservative estimate of the cost savings would thus be between $8 million and $13 million per year.

Q. What is the basis for your estimate of the cost of the RC/ITO alternative?

A. The estimated range for the costs of obtaining Order No. 888 services through an RC/ITO is based on several data sources: the costs of unbundled RTO services as proposed by SPP; the Companies' actual experience as members of MISO during the period when MISO operated as a Day 1 RTO; a cost-benefit analysis of the Companies' alternatives to MISO membership; and Duke Power's estimates of obtaining Order No. 888 services from MISO.

Q. What is the cost evidence available from the Companies' actual experience as members of MISO during the period when MISO operated as a Day 1 RTO?

A. The Companies, as members of MISO from the time it began operating as a Day 1 RTO in 2002, were paying approximately $6 million per year in charges for MISO to provide what was essentially Order No. 888 functional services.

Q. What is the cost evidence available from the cost-benefit analysis of the Companies' alternatives to MISO membership?

A. In June 2004, the Kentucky PSC ordered the Companies to conduct an investigation into the costs and benefits of membership in MISO compared to a set of alternatives that included membership in PJM, membership in the SPP RTO as well as an arrangement similar in character to the one envisioned in the Companies' present proposal before the Commission.[8] In that study, the estimated cost for the Companies becoming full members of the SPP RTO was $6.9 million per year for the six-year study period of 2005

[8] *Investigation Into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.*, KPSC Case No. 2003-00266, Order issued June 22, 2004. This investigation was supplemental to the proceeding that had been initiated by the KPSC in July 2003 that produced the Companies' initial cost-benefit study and subsequent hearings. The details of that study can be found in *Supplemental Investigation Into the Costs and Benefits to Louisville Gas and Electric Company and Kentucky Utilities Company of RTO Participation Options*, prepared for Louisville Gas and Electric Company and Kentucky Utilities Company, prepared by Christensen Associates Energy Consulting, September 29, 2004.

to 2010. The SPP RTO operates as a Day 1 RTO and would thus provide the Order No. 888 functional services including Reliability Coordinator service. This figure probably overestimates the cost to the Companies of obtaining unbundled Order No. 888 services under contract with SPP, as opposed to joining it, because the Companies would not be receiving all of the services that SPP provides to its members.

During the course of the Kentucky PSC-ordered investigation, the costs of separately contracting for Reliability Coordinator ("RC") services through a non-RTO, NERC-certified RC were estimated at $500,000 per year. The costs of such services have likely increased recently due to the recent coordination agreements reached among the several RTOs (*i.e.*, MISO, PJM, and SPP), and between MISO and TVA, that require additional investments in advanced monitoring and communications software. Therefore, a current reasonable estimate of the costs of RC services may be closer to $1 million per year.

Q. What is the cost evidence available from Duke Power's estimates of obtaining Order No. 888 services from MISO?

A. Duke Power estimated that to obtain both RC/ITO and Independent Market Monitor ("IMM") services from MISO would cost between $3 and $4 million per year. This figure is considerably less than Duke Power undoubtedly would pay through Schedule 10, 16, and 17 charges if it became a member of MISO, and is certainly less than what the Companies were paying MISO for Schedule 10 services alone. The set of services Duke Power would obtain from MISO does not contain RC service. The expected cost to Duke Power of this bundle of services is $2 to $3 million per year lower than the cost to the Companies' customers of the Companies' MISO Day 1 RTO membership of $6.4

million per year. The Companies do not plan to contract for IMM services, so it is reasonable to expect that the cost of obtaining Order No. 888 services would likely not exceed $4 million per year. If the Companies contract with another entity for Reliability Coordinator services, the total package of services might cost approximately $5 million annually.

Q. What is the basis for your estimate of the costs of the Companies' membership in MISO?

A. In contrast to the costs of obtaining Order No. 888 services, the cost of the Companies' continued obligatory participation in MISO's Day 2 markets, in order to satisfy Order No. 888, was estimated in the Supplemental Investigation to lie between $15 million and $17 million per year. This cost consisted of $15 million per year of Administrative Charges under MISO's OATT Schedules 10, 16 and 17. These were costs about which the Companies were reasonably certain. The upper end of the cost range was based on an additional conservative estimate of $2 million per year in uplift costs (the Companies' share of socialized RTO costs) plus an expectation of a five percent underfunding of FTR payments from MISO to the Companies. In other words, according to the Supplemental Investigation, the Companies could fulfill the Order No. 888 requirements through an ITO and an RC for approximately $8 to $13 million per year less than if they continue as MISO members.

Q. Do the Companies have actual cost estimates for the services to be provided by SPP as ITO and TVA as RC?

A. No. Negotiations with the selected RC and ITO are ongoing and rates for the services to be provided have not been settled at this time. However, officials at the Companies inform me that the negotiations will likely lead to rates for these services that are consistent with the projections I provide in this testimony.

Q. Would the exit fee that the Companies are required to pay to leave MISO negate the savings that you predict will inure to the Companies and their customers under an RC/ITO arrangement?

A. No. While negotiations between the Companies and MISO on the exact value of the exit fee are ongoing, the exit fee is estimated to cost the Companies and their customers in the range of $28 to $38 million. The savings of $8 to $13 million per year from moving to an RC/ITO arrangement means that the exit fee payment will be recovered roughly within three to four years. The savings from exiting MISO and moving to an RC/ITO arrangement will exceed the exit fee by a significant margin in the longer run. The exit fee payment ensures that the Companies have met their obligation under the MISO Transmission Owner's agreement to hold harmless those transmission owners that remain members.

VII. THE COMMISSION SHOULD APPROVE THE COMPANIES' PLAN TO DEVELOP AN RC/ITO

Q. Please summarize the reasons that the Companies' plan merits Commission approval.

A. For the Companies and their customers, the Day 2 RTO model is a relatively costly way to satisfy Order No. 888 objectives. The Companies proposed RC/ITO model, by contrast, can achieve the level of independence necessary to satisfy Order No. 888 at lower cost, while ensuring that transmission services and rates are transparent, competition in generation is facilitated and reliability is maintained. It enables the

Companies to exercise greater control over their assets and allows the Kentucky PSC to continue its longstanding control over the Companies' costs that go into rates. It reduces the financial risks that the Companies and their customers will be exposed to in the wholesale market, thereby reducing the Companies' costs of risk management that its customers must ultimately bear.

In light of the Commission's concern over RTO governance, cost accountability, and transparency, the Companies' RC/ITO proposal gives the Commission a policy option to introduce customer choice – the mechanism of a market – to discipline RTO management and costs. RTOs will become more accountable when customers can "vote with their feet." When the RC/ITO concept involves an RTO in providing unbundled Order No. 888 services to non-RTO utilities, it introduces a much needed degree of competition among RTOs and therefore begins to discipline RTO costs. Existing RTO members would benefit from this unbundling of services because it spreads the recovery of costs to a larger base of customers. Furthermore, the unbundling of RTO services, for members as well as non-members, gives existing and potential RTO customers the ability to signal how much they value RTO services. The ability to choose plays an important role in corporate governance in other industries and can do so in this sector of the electric industry as well, to the long-term benefit of all consumers.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

STATE OF VIRGINIA)
) **SS:**
CITY OF ALEXANDRIA)

The undersigned, Mathew J. Morey, being duly sworn, deposes and says he is a Senior Consultant for Christensen Associates Energy Consulting LLC, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

MATHEW J. MOREY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 6th day of October 2005.

Notary Public

My Commission Expires:

31 DEC 2008

OFFICIAL SEAL
EDWIN T. REID
Notary Public
COMMONWEALTH OF VIRGINIA
My Commission Expires
DECEMBER 31, 2008

Exhibit D

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LG&E Energy LLC	**)**	**Docket No. ER06-___-000**
	)	
Louisville Gas & Electric Company, *et al*.	**)**	**Docket No. EC98-2-___**
	)	
Louisville Gas & Electric Company, *et al*.	**)**	**Docket No. EC00-67-___**
	)	
E.ON AG, *et al*.	**)**	**Docket No. EC01-115-___**

TESTIMONY OF WILLIAM H. HIERONYMUS

Q. Please state your name and business address.

A. My name is William H. Hieronymus. I am a Vice President of CRA International at their Boston office, 200 Clarendon Street, T-33, Boston, MA 02116.

Q. Please summarize your qualifications.

A. I am an economist who has spent the past 30 years predominantly analyzing issues related to the electric power industry. I have testified before the Commission, and in other venues, on market power issues on a great many occasions. My résumé is attached as Exhibit WHH-1.

Q. What is the purpose of your testimony in this proceeding?

A. LG&E Energy LLC ("LG&E Energy"), on behalf of its operating companies Louisville Gas and Electric Company ("LGE") and Kentucky Utilities ("KU") (all collectively "Applicants"), are seeking to withdraw from the Midwest ISO ("MISO"), and have asked me to opine on market power issues relating to their withdrawal proposal. I have reviewed Applicants' proposal and, as discussed below, find it is consistent with commitments made by Applicants' in prior merger proceedings and, further, will have no significant adverse competitive effects.

Q. Please describe Applicants' prior commitments.

A. In approving the merger of LGE and KU in Docket Nos. EC98-2-000, *et al.*, the Commission relied in part on the companies' participation in the formation of MISO to mitigate market power concerns with regard to KU's requirements customers. In particular, the Commission stated:

> We regard LG&E and KU's participation as parties in the Midwest ISO filings as evidence of their commitment to membership in the Midwest ISO. Our approval of the merger is based on LG&E and KU's continued participation in the Midwest ISO. If LG&E and KU seek permission to withdraw from the Midwest ISO proceedings or the ISO once it is operating, we will evaluate that request in light of its impact on competition in the KU destination markets, use our authority under section 203(b) of the FPA to address any concerns, and order further procedures as appropriate.[1]

In approving E.ON's indirect acquisition of LG&E Energy in 2001, the Commission also relied on Applicants' commitments to remain part of MISO or, alternatively, to be a member of a Commission-approved RTO. The Commission there stated:

> LG&E and KU have committed to transfer operational control of their transmission systems to the Midwest ISO and will remain members of the Midwest ISO at least until the end of 2002. Furthermore, they have committed to be members of a Commission-approved RTO thereafter. Therefore, *they lack the ability to exploit their transmission assets* to harm competition in wholesale electricity markets.[2]

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[1] *Louisville Gas & Elec. Co. and Kentucky Utilities Co.,* 82 FERC ¶61,308 (1998) ("LGE-KU Merger Order"). It is worth noting that, at the time, only "Day 1" operations were contemplated to be part of MISO, that is, no "Day 2" energy market was planned.

[2] *E.ON AG*, 97 FERC ¶ 61,049 at 61,283 (2001) (emphasis added). The Commission did not address the RTO commitment in approving the merger of LG&E Energy Corporation with Powergen plc in 2000. *Louisville Gas and Elec. Co.,* 91 FERC ¶ 61,321 (2000).

Thus the Commission has consistently expressed concern over the Applicant's ability to operate transmission in a way that harms wholesale competition, particularly with respect to the KU destination markets

Q. What are Applicants proposing to do now?

A. As I mentioned above, LGE and KU now are seeking to withdraw from MISO. As discussed in detail in the transmittal letter accompanying the filing and as demonstrated by the draft and executed contracts attached to the filing, as part of this withdrawal process, Applicants are proposing to engage an Independent Transmission Organization ("ITO") and Reliability Coordinator ("RC") to provide certain functions now performed by MISO.

The ITO proposal and elements of the RC proposal are modeled on a proposal filed by Duke Power[3] that in turn is intended to conform to the Commission's orders regarding the Entergy ITC.[4] In addition, unlike the other proposals, Applicants' proposal:

- Contemplates separate unaffiliated, independent third-party providion of both RC and ITO services. By contrast, Entergy vests both functions in the same body, and Duke retains the RC functions. As a result, Duke's proposal requires an independent market monitor whereas neither LG&E nor Entergy provides for one.
- Includes a Planning Authority function as part of the RC responsibilities. Both Duke and Entergy retain this function, subject to stakeholder inputs.
- Has seams arrangements already in place with Tennessee Valley Authority, MISO and PJM. Hence, there are no operational seams issues to address. Thus, unlike Entergy and Duke, there is no pancaking for through, out or in transactions with TVA, MISO or PJM counterparties.

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[3] Duke Power, Docket No. ER05-1236-000, Application to Revise Open Access Transmission Tariff and Institute an Independent Transmission Coordinator, July 22, 2005.

[4] *Entergy Servs., Inc*. 110 FERC ¶ 61,295, clarified, 111 FERC ¶ 61,222 (2005); *Entergy Servs., Inc*. Docket No. ER05-1065 (May 27, 2005).

The purpose of my testimony is to examine whether the proposed tariff provisions, particularly the delegation of functions to the ITO and RC, adequately address the market power concerns that the Commission found in its earlier merger orders would be adequately addressed by membership in MISO.

Q. Do you find that the ITO and RC adequately address the market power concerns that the Commission found in its earlier merger orders?

A. Yes. Applicants' proposal adequately addresses the competitive concerns that were resolved by the merger commitments Applicants offered (and the Commission accepted) with respect to Applicants' prior mergers. Further, Applicants' proposal will have no significant adverse competitive effects. In all, I believe that Applicants' proposal is comparable in all material respects to the membership in MISO as contemplated at the time of the commitments insofar as Applicants' proposal will achieve the same competitive benefits – albeit through different means – that the Commission sought through the merger commitments imposed on Applicants in those prior orders.[5]

Q. In approving the LGE-KU merger, what market power concerns did the Commission find were mitigated by MISO membership?

A. Although the Commission specifically identified market power as the concern that necessitated mitigation, it noted both horizontal and vertical benefits to LGE and KU's MISO membership. The horizontal benefit arose from market enlargement as a result of the (at that time, potential) elimination of rate pancaking.[6]

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[5] The appropriate comparison is to MISO as it was planned in 1998 and 2001, not to, for example, the now abandoned Standard Market Design. For example, as of 2001, MISO had not proposed development of a "Day 2" market.

[6] *LGE-KU Merger Order* ("Second, they [ISOs] can ensure expansion of geographic markets by eliminating pancaked transmission rates in regions. Through the availability of transmission service at a single rate, the number

The vertical benefits noted related generally to mitigation of potential manipulation of the transmission system.[7] Enumerated benefits cited by the Commission were:

- Impartial transmission planning to reduce congestion,
- Fair and efficient congestion management,
- Removal of abuses of native load priority,
- Elimination of incentives to curtail generation competitors, and
- Removal of incentives to game OASIS management.

Horizontal Benefits of ISO Membership

Q. Please begin with the Commission's statement of the horizontal benefit of ISO membership, namely elimination of rate pancaking. Does Applicants' proposal preserve this benefit?

A. Yes, the expanded market access identified as an additional benefit of Applicants' MISO membership is preserved. Applicants' proposal retains the benefit of de-pancaked rates. It will maintain the status quo with respect to MISO transmission rates and continue the elimination of seams such as exists today. This will be accomplished by amending

of suppliers able to reach markets (such as the KU requirements customers (sic) destination market) increases, thereby lowering market concentration." [non-relevant footnote omitted]).

[7] *Ibid*. ("First, by separating the control of transmission from generation, they [ISOs] can reduce, if not eliminate altogether, any potential manipulation of the post-merger transmission system. [Footnote: Without commenting on the merits of the Midwest ISO, if properly structured, an ISO, or perhaps a grid company, can improve the process for determining system expansion needs because that process will no longer be dominated by a transmission operator that also owns generation assets. A properly structured ISO would have no economic stake in maintaining congested interfaces. Moreover, an ISO could eliminate the transmission owner's priority to use internal system capacity for native load. The ISO could also eliminate the incentive to engage in strategic curtailments of generation owned by the transmission operator's generation service competitors. Also, the potential for gaming OASIS operations could be removed. These benefits will promote generation entry and competition because the affected markets will be perceived by potential entrants as fairer as a result of the transmission system no longer being controlled by their generation service competitors.]")

Applicants' Open Access Transmission Tariff ("OATT") to replicate MISO through-and-out rates.[8]

Specifically, as explained in more detail in the transmittal letter, Applicants will provide point-to-point transmission for service through their system and between their system and points within existing MISO and PJM systems. Applicants also propose to provide network service between points of receipt and points of delivery on their system and MISO. These "Reciprocity Firm" services are intended to put all transmission system users on the same cost footing as if Applicants had remained in MISO. While this provision is subject to reciprocal treatment, MISO has indicated that such treatment is agreeable. This includes the effect of the seams agreement between MISO and PJM. Hence, the Applicants' proposal includes no pancaking with respect to transactions involving either of these two RTOs.

Q. Therefore, does the proposal to maintain de-pancaking mimic the horizontal competition benefit of MISO membership discussed by the Commission in LGE-KU merger order?

A. Yes.

Q. Before we turn to the vertical benefits of MISO membership relied on by the Commission in approving the mergers, have you considered the impact of LGE's and KU's withdrawal on market concentration?

A. Yes, I have. In most respects, actual concentration should not change since, as the Commission's orders noted, de-pancaking was the principal deconcentrating impact of

[8] As detailed in the Filing Letter, there are minor differences between the proposed tariff and the MISO tariff. Most notably, for destinations outside of MISO and PJM, the LGE Energy tariff rate will be substituted for the MISO tariff rate.

membership in MISO. However, under the Commission's existing screens for market rate authority, there will be implications for analyzing generation market power in Applicants' control area and the MISO footprint.

Q. What is the impact of Applicants' withdrawal on market rate authority screens for Applicants' control area?

A. Under the Commission's current screen methodology, the default geographic region for analysis is the individual control area for non-RTO members and the RTO control area for RTO members. Hence, upon Applicants' withdrawal from MISO, the relevant control area shifts from the relatively unconcentrated MISO footprint to Applicants' more concentrated control area.

Q. What is the potential effect of Applicants' withdrawal from MISO on concentration within MISO?

A. As I noted above, there should be little if any real effect on concentration since the actual underlying facts (no pancaking, etc.) will be little changed. However, as market power screens are conducted for market rate authority purposes, Applicants' withdrawal will shrink the MISO market as defined by the screens, although only slightly. In consequence, the market shares of MISO's largest participants will increase. Potentially, this could increase market concentration in MISO definitionally (though not at all impacting the Applicants' ability to transact in MISO, or MISO members' ability to transact in Applicants' control area).

Q. Have you analyzed the effect of Applicants' withdrawal on market concentration in MISO?

A. Yes. I conducted an analysis of market concentration for the MISO overall, with and without Applicants as transmission-owning members. The analysis is very conservative insofar as I exclude imports (which, if included, would reduce concentration levels). I found that the MISO market is very unconcentrated, with or without Applicants, as measured by Economic Capacity.

MISO's Market Monitor, similarly, found that the MISO market overall was unconcentrated,[9] and also computed HHIs for various subregions within MISO. While these historically-based subregions should not be assumed to be relevant geographic markets, nevertheless, it is worth noting that the Market Monitor determined that the ECAR subregion, which includes Applicants' control area, also is unconcentrated. Moreover, there is considerable excess capacity in MISO. According to the Market Monitor, the reserve margin is 26.7 percent.

Q. Will Applicants' withdrawal increase the market concentration in MISO?

A. Yes, but only slightly, as shown below.[10] Total MISO generation is about 115,000 MW (after accounting for outages). Applicants' generation in MISO is approximately 7,500 MW (after outages). Plainly, the withdrawal of one moderately large seller will not materially increase the MISO HHI. Indeed, according to my analysis, the current MISO HHI is in the 650-800 range and the HHI without Applicants will increase by only about 50 points – thus remaining unconcentrated.

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[9] Potomac Economics, Ltd., "2004 State of the Market Report, Midwest ISO," June 2005.

[10] I have included in my workpapers a description of the assumptions used in the analysis.

Economic Capacity

Market	Period	Price	MISO, with LG&E Market Size	MISO, with LG&E HHI	MISO, without LG&E Market Size	MISO, without LG&E HHI	Change Market Size	Change HHI
MISO	S_SP1	$250	122,755	642	115,279	688	(7,476)	46
MISO	S_SP2	$80	112,234	652	105,149	700	(7,085)	48
MISO	S_P	$60	93,304	684	87,787	733	(5,517)	49
MISO	S_OP	$30	77,908	780	73,315	843	(4,593)	63
MISO	W_SP	$85	114,179	650	106,723	698	(7,456)	48
MISO	W_P	$65	93,241	680	87,667	730	(5,574)	50
MISO	W_OP	$40	82,835	761	77,387	823	(5,448)	62
MISO	SH_SP	$75	83,568	652	79,207	696	(4,361)	44
MISO	SH_P	$55	74,317	676	69,990	724	(4,327)	48
MISO	SH_OP	$35	64,198	754	60,194	815	(4,004)	61

The modest effect on market HHIs is also reflected in the Available Economic Capacity analysis, shown below. This analysis is more difficult, because it requires evaluating individual utility load obligations in the face of retail access in a number of states within the MISO footprint.[11] The results indicate that the market is unconcentrated in all but very low-priced time periods, and even then it is barely in the moderately concentrated range. Applicants' withdrawal from MISO has an HHI effect of well less than 100 points, with one exception. The exception, at a shoulder price of $35/MWh, shows an HHI change of 106 and a market concentration of 1,120.[12]

Clearly there should be no concern based on the HHI results for either Economic Capacity or Available Economic Capacity with respect to the effect of Applicants' withdrawal from MISO.

[11] I have included a description of the analysis and assumptions in workpapers.

[12] Recall that these calculations exclude imports. Due to the fact that the amount of Available Economic Capacity in MISO is much less that the amount of Economic Capacity, excluding imports has a magnified effect. Had imports been included, both HHI changes and market concentration would have been materially less.

Available Economic Capacity

			MISO, with LG&E		MISO, without LG&E		Change	
			Market Size	HHI	Market Size	HHI	Market Size	HHI
MISO	S_SP1	$250	18,137	580	17,225	595	(912)	15
MISO	S_SP2	$80	17,289	579	16,249	599	(1,040)	20
MISO	S_P	$60	15,704	608	15,068	642	(636)	34
MISO	S_OP	$30	16,540	1,027	15,736	1,108	(804)	81
MISO	W_SP	$85	29,829	580	27,582	611	(2,247)	31
MISO	W_P	$65	20,399	616	19,333	656	(1,066)	40
MISO	W_OP	$40	20,374	881	18,912	963	(1,462)	82
MISO	SH_SP	$75	11,447	758	11,447	758	-	0
MISO	SH_P	$55	10,531	765	10,131	811	(400)	46
MISO	SH_OP	$35	10,982	1,014	10,162	1,120	(820)	106

Q. Have these types of Delivered Price Test analyses been used before to analyze changes in concentration resulting in a change in geographic market definition, as is the case here?

A. To the best of my knowledge, no, they have not. These screens are designed to analyze the change in market concentration resulting from the merger or two or more entities that own or control electric generation. In such instances, the geographic market used in the analysis does not change as a result of the merger. I am not aware of these analyses ever being used as an analytical tool for examining changes in concentration as a result of an entity leaving an RTO. Accordingly, any screen "failures" should not be considered indicative of any problems bought about by Applicants' withdrawal from MISO.

Vertical Benefits of ISO Membership

Q. What standard are you using in evaluating Applicants' proposal with respect to vertical issues?

A. Generally, I am comparing the proposal to the status quo, i.e., if Applicants were to remain in MISO. If relevant functions delegated to the MISO are now to be delegated to the ITO and RC, then there is no reduction in competitiveness arising from substitution of the proposed tariff provisions from the applicability of the MISO tariff.[13] An alternative standard would be whether the proposal meets the criteria set forth in the Commission's decisions on the Entergy ITC proposal. More generally, I also compare the Applicants' proposal to the Duke proposal pending before the Commission.

Q. Please turn now to the vertical benefits of MISO membership that the Commission cited in the LGE-KU merger Order that you listed previously. Does Applicants' proposal provide for impartial transmission system planning to the same degree as MISO does today?

A. Yes. The Reliability Coordinator ("RC") will have functions that closely parallel relevant functions provided by MISO. In particular, the RC will:

- Perform Reliability Coordinator functions under NERC Version 0 Reliability Standards,
- Provide security coordination,
- Coordinate Applicants' transmission planning efforts with others in the TVA reliability area and with neighboring Planning Authorities,
- Review (and have approval rights over) Applicants' proposed maintenance schedules,
- Review Applicants' base case model used by the ITO for the purpose of, among other things, calculating ATCs, and
- Provide an independent assessment and evaluation of Applicants' annual plan for transmission upgrade projects.

Specifically, the RC will also review and coordinate Applicants' planning criteria to assure that they are appropriate, transparent and consistent with regional requirements; review the transmission model used for planning purposes, and independently assess

[13] In this context, it is relevant that functions that were delegated to RTOs in the Commission's now-abandoned Standard Market Design and in some of the Eastern RTOs were retained by Transmission Operators in MISO.

Applicants' annual transmission plan. On the basis of this review, the RC will propose suggested revisions. The RC will have an affirmative obligation to have information concerning areas of disagreement posted on the ITO-administered Applicants' OASIS.

Q. The second of the stated benefits is removal of native load priority. Would Applicants' proposal eliminate native load priority?

A. No. However, the same is true for MISO today, as evidenced by the extensive grandfathering of physical transmission rights in MISO. Eliminating native load priority was at one time a policy goal of the Commission. However, that goal appears to have substantially lapsed. Moreover, removing native load priority would, to my lay understanding, be inconsistent with the Energy Policy Act of 2005.

Q. Does Applicants' proposal remove the incentive for the transmission operator to curtail the operations of generators that compete with Applicants?

A. Yes. The ITO will be responsible for accepting and processing all requests for transmission service and for OASIS management more generally. The RC will have authority over curtailments in the reliability area that will now include Applicants' control area. The RC will have full authority over all interchange schedules and transactions. Since both the ITO and RC are fully independent of Applicants, they will have no incentive to disadvantage Applicants' competitors. Further, Applicants themselves will have no ability to do so. As a factual matter there is little independent generation in Applicants' control area that potentially competes with Applicants' generation. Thus, the predominant competition faced by Applicants is transmission through or into the control area. Such transmission requests will be accepted (or not) by the independent ITC and subject to TLRs called by the independent RC.

Q. Will Applicants' proposal eliminate the incentive for manipulation of OASIS management?

A. Yes. The ITO will have full authority over all OASIS functions, including determination of ATCs and TTCs, and receipt and processing of all requests for transmission service. It also will have full authority to process all generation interconnection requests, including the performance of system impact studies.

Q. You stated also that you compared Applicants' proposal for an ITC and RC to the Duke proposal and to the Entergy proposal as conditionally accepted by the Commission. Are these proposals indeed similar?

A. Yes. As noted previously, the areas of dissimilarity are few and relatively minor. Generally, where they differ, Applicants' proposal goes beyond the Duke and Entergy proposals in terms of independence of functions and improving the competitiveness of markets. One major difference is that Applicants' proposal maintains the de-pancaking of transmission achieved while it was a member of MISO. The other two proposals maintain control area-level transmission rates. Another difference is that Applicants' proposal includes transmission planning oversight and coordination by the RC. These functions are retained by Duke and Entergy in their proposals. Entergy puts both RC and ITC functions in the same independent entity, which is a difference without much significance.

Q. In the Entergy Order, the Commission relied on the presumption that the SPP would be the independent entity taking up delegated transmission functions. Have Applicants selected the entities that will be the ITC and RC?

A. Yes. The SPP will be the ITC. Based on the Entergy order, the Commission presumably is satisfied with the competence and independence of SPP. TVA has been selected to be the RC. Clearly, TVA is both capable of performing these functions and fully independent. Moreover, as the operator of a large control area adjacent to Applicants, TVA likely will be able to achieve coordination benefits that would not be achievable by others who responded to the Applicants' RC RFP.

Q. Does this complete your testimony?

A. Yes, it does.

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LG&E Energy LLC Louisville Gas and Electric Company Kentucky Utilities Company	)))	Docket No. EC05-___

AFFIDAVIT

County of Suffolk §
Commonwealth of Massachusetts §
§

WILLIAM H. HIERONYMUS being duly sworn, deposes and states: that he prepared the Affidavit and Exhibits of William H. Hieronymus and that the statements contained therein and the Exhibits attached hereto are true and correct to the best of his knowledge and belief.

William H. Hieronymus
William H. Hieronymus

SUBSCRIBED AND SWORN TO BEFORE ME, this the 5th day of October 2005.

Mary Jeanne Luchkovitz
Notary Public, Commonwealth of Massachusetts

MARY JEANNE LUCHKOVITZ
NOTARY PUBLIC
COMMONWEALTH OF MASSACHUSETTS
My Commission Expires Aug. 25, 2011

Exhibit WHH-1

WILLIAM H. HIERONYMUS

Ph.D. Economics
University of Michigan

M.A. Economics
University of Michigan

B.A. Social Sciences
University of Iowa

William Hieronymus has consulted extensively to managements of electricity and gas companies, their counsel, regulators, and policymakers. His principal areas of concentration are the structure and regulation of network utilities and associated management, policy, and regulatory issues. Dr. Hieronymus has spent the last seventeen years working on the restructuring and privatization of utility systems in the U.S. and internationally. In this context he has assisted the managements of energy companies on corporate and regulatory strategy, particularly relating to asset acquisition and divestiture. He has testified extensively on regulatory policy issues and on market power issues related to mergers and acquisitions. In his thirty years of consulting to this sector, he also has performed a number of more specific functional tasks, including analyzing potential investments; assisting in negotiation of power contracts, tariff formation, demand forecasting, and fuels market forecasting. Dr. Hieronymus has testified frequently on behalf of energy sector clients before regulatory bodies, federal courts, and legislative bodies in the United States the United Kingdom and Australia. He has contributed to numerous projects, including the following:

ELECTRICITY SECTOR STRUCTURE, REGULATION, AND RELATED MANAGEMENT AND PLANNING ISSUES

U.S. Market Restructuring Assignments

- Dr. Hieronymus serves as an advisor to the senior executives of electric utilities on restructuring and related regulatory issues, and he has worked with senior management in developing strategies for shaping and adapting to the emerging competitive market in electricity. Related to some of these assignments, he has testified before state agencies on regulatory policies and on contract and asset valuation.

- For utilities seeking merger approval, Dr. Hieronymus has prepared and testified to market power analyses at FERC and before state commissions. He also has assisted in discussions with the Antitrust Division of the Department of Justice and in responding to information requests. The mergers on which Dr. Hieronymus has testified include both electricity mergers and combination mergers involving electricity and gas companies. Among the major mergers on which he has testified are EEG (Exelon and PSE&G), Sempra (Enova and Pacific Enterprises), Xcel (New Century Energy and Northern States Power), Exelon (Commonwealth Edison and Philadelphia Electric), AEP (American Electric Power and Central and Southwest), Dynegy-Illinois Power, Con Edison-Orange and Rockland, Dominion-Consolidated Natural Gas, NiSource-Columbia Energy, E-on-PowerGen/LG&E and NYSEG-RG&E and Exelon-PSE&G. He also submitted testimony in mergers that were terminated for unrelated reasons, including Entergy-Florida Power and Light, Northern States Power and Wisconsin Energy, KCP&L and Utilicorp and Consolidated Edison-Northeast Utilities. Testimony on similar topics has been filed for a number of smaller utility mergers and for asset acquisitions. Dr Hieronymus has also assisted numerous clients in the pre-merger screening of potential acquisitions and merger partners.

- For utilities seeking to establish or extend market rate authority, Dr. Hieronymus has provided numerous analyses concerning market power in support of submissions under Sections 205 of the Federal Power Act.

- For utilities and power pools engaged in restructuring activities, he has assisted in examining various facets of proposed reforms. Such analysis has included features of the proposals affecting market efficiency and those that have potential consequences for market power. Where relevant, the analysis also has examined the effects of alternative reforms on the client's financial performance and achievement of other objectives.

- For generators and marketers, Dr. Hieronymus has testified extensively in the regulatory proceedings concerning the electricity crisis in the WECC that occurred during May 2000 and May 2001. His testimony concerned, inter alia, the economics of long term contracts entered into during that period the behavior of market participants during the crisis period and the nexus between purportedly dysfunctional spot markets and forward contracts.

- For the New England Power Pool (NEPOOL), Dr. Hieronymus examined the issue of market power in connection with NEPOOL's movement to market-based pricing for energy, capacity, and ancillary services. He also assisted the New England utilities in preparing their market power mitigation proposal. The main results of his analysis were incorporated in NEPOOL's market power filing before FERC and in ISO-New England's market power mitigation rules.

- For a coalition of independent generators, he provided affidavits advising FERC on changes to the rules under which the northeastern U.S. power pools operate.

- Dr. Hieronymus has contributed substantially to projects dealing with the restructuring of the California electricity industry. In this context he also is a witness in California and FERC proceedings on the subject of market power and mitigation and more recently before FERC in connection with transactions related to PG&E's bankruptcy and on the contracts signed between merchant generators and various buyers.

Valuation of Utility Assets in North America

- Dr. Hieronymus has testified in state securitization and stranded cost quantification proceedings, primarily in forecasting the level of market prices that should be used in assessing the future revenues and the operating contribution earned by the owner of utility assets in energy and capacity markets. The market price analyses are tailored to the specific features of the market in which a utility will operate and reflect transmission-constrained trading over a wide geographic area. He also has testified in rebuttal to other parties' testimony concerning stranded costs, and has assisted companies in internal stranded cost and asset valuation studies.

- He was the primary valuation witness on behalf of a western utility in an arbitration proceeding concerning the value of a combined cycle plant coming off lease that the utility wished to purchase.

- He assisted a bidder in determining the commercial terms of plant purchase offers as well as assisting clients in assessing the regulatory feasibility of potential acquisitions and mergers.

- He has testified concerning the value of terminated long term contracts in connection with contract defaults by bankrupt power marketers and merchant generators.

Other U.S. Utility Engagements

- Dr. Hieronymus has contributed to the development of several benchmarking analyses for U.S. utilities. These have been used in work with clients to develop regulatory proposals, set cost reduction targets, restructure internal operations, and assess merger savings.

- Dr. Hieronymus was a co-developer of a market simulation package tailored to region-specific applications. He and other senior personnel have conducted numerous multi-day training sessions using the package to help utility clients in educating management regarding the consequences of wholesale and retail deregulation and in developing the skills necessary to succeed in this environment.

- He has made numerous presentations to U.S. utility managements regarding overseas electricity systems.

- In connection with nuclear generating plants nearing completion, he has testified in Pennsylvania, Louisiana, Arizona, Illinois, Missouri, New York, Texas, Arkansas, New Mexico, and before the Federal Energy Regulatory Commission regarding plant-in-service rate cases on the issues of equitable and economically efficient treatment of plant costs for tariff-setting purposes, regulatory treatment of new plants in other jurisdictions, the prudence of past system planning decisions and assumptions, performance incentives, and the life-cycle costs and benefits of the units. In these and other utility regulatory proceedings, Dr. Hieronymus and his colleagues have provided extensive support to counsel, including preparation of interrogatories, cross-examination support, and assistance in writing briefs.

- On behalf of utilities in the states of Michigan, Massachusetts, New York, Maine, Indiana, Pennsylvania, New Hampshire, and Illinois, he has submitted testimony in regulatory proceedings on the economics of completing nuclear generating plants that were then under construction. His testimony has covered the likely cost of plant completion; forecasts of operating performance; and extensive analyses of the impacts of completion, deferral, and cancellation upon ratepayers and shareholders. For the senior managements and boards of utilities engaged in nuclear plant construction, Dr. Hieronymus has performed a number of highly confidential assignments to support strategic decisions concerning the continuance of construction.

- For an eastern Pennsylvania utility that suffered a nuclear plant shutdown due to NRC sanctions relating to plant management, he filed testimony regarding the extent to which replacement power cost exceeded the costs that would have occurred but for the shutdown.

- For a major Midwestern utility, Dr. Hieronymus headed a team that assisted senior management in devising its strategic plans, including examination of such issues as plant refurbishment/life extension strategies, impacts of increased competition, and available diversification opportunities.

- On behalf of two West Coast utilities, Dr. Hieronymus testified in a needs certification hearing for a major coal-fired generation complex concerning the economics of the facility relative to competing sources of power, particularly unconventional sources and demand reductions.

- For a large western combination utility, he participated in a major 18-month effort to provide the client with an integrated planning and rate case management system.

- For two Midwestern utilities, Dr. Hieronymus prepared an analysis of intervenor-proposed modifications to the utilities' resource plans. He then testified on their behalf before a legislative committee.

U.K. Assignments

- Following promulgation of the white paper that established the general framework for privatization of the electricity industry in the United Kingdom, Dr. Hieronymus participated extensively in the task forces charged with developing the new market system and regulatory regime. His work on behalf of the Electricity Council and the twelve regional distribution and retail supply companies focused on the proposed regulatory regime, including the price cap and regulatory formulas, and distribution and transmission use of system tariffs. He was an active participant in industry-government task forces charged with creating the legislation, regulatory framework, initial contracts, and rules of the pooling and settlements system. He also assisted the regional companies in the valuation of initial contract offers from the generators, including supporting their successful refusal to contract for the proposed nuclear power plants that subsequently were canceled as being non-commercial.

- During the preparation for privatization, Dr. Hieronymus assisted several individual U.K. electricity companies in understanding the evolving system, in developing use of system tariffs, and in enhancing commercial capabilities in power purchasing and contracting. He continued to advise a number of clients, including regional companies, power developers, large industrial customers, and financial institutions on the U.K. power system for a number of years after privatization.

- Dr. Hieronymus assisted four of the regional electricity companies in negotiating equity ownership positions and developing the power purchase contracts for a 1,825 megawatt combined cycle gas station. He also assisted clients in evaluating other potential generating investments including cogeneration and non-conventional resources.

- Dr. Hieronymus also has consulted on the separate reorganization and privatization of the Scottish electricity sector. Part of his role in that privatization included advising the larger of the two Scottish companies and, through it, the Secretary of State on all phases of the restructuring and privatization, including the drafting of regulations, asset valuation, and company strategy.

- He assisted one of the Regional Electricity Companies in England and Wales in the 1993 through 1995 regulatory proceedings that reset the price caps for its retailing and distribution businesses. Included in this assignment was consideration of such policy issues as incentives for the economic purchasing of power, the scope of price control, and the use of comparisons among companies as a basis for price regulation. Dr. Hieronymus's model for determining network refurbishment needs was used by the regulator in determining revenue allowances for capital investments.

- He assisted one of the Regional Electricity Companies in its defense against a hostile takeover, including preparation of its submission to the Cabinet Minister who had the responsibility for determining whether the merger should be referred to the competition authority.

Assignments Outside the U.S. and U.K.

- Dr. Hieronymus testified before the federal court of Australia concerning the market power implications of acquisition of a share of a large coal-fired generating facility by a large retail and distribution company.

- Dr. Hieronymus assisted a large state-owned European electricity company in evaluating the impacts of the 1997 EU directive on electricity that inter alia requires retail access and competitive markets for generation. The assignment included advice on the organizational solution to elements of the directive requiring a separate transmission system operator and the business need to create a competitive marketing function.

- For the European Bank for Reconstruction and Development, he performed analyses of least-cost power options and evaluated the return on a major investment that the Bank was considering for a partially completed nuclear plant in Slovakia. Part of this assignment involved developing a forecast of electricity prices, both in Eastern Europe and for potential exports to the West.

- For the OECD he performed a study of energy subsidies worldwide and the impact of subsidy elimination on the environment, particularly on greenhouse gases.

- For the Magyar Villamos Muvek Troszt, the electricity company of Hungary, Dr. Hieronymus developed a contract framework to link the operations of the different entities of an electricity sector in the process of moving from a centralized command- and-control system to a decentralized, corporatized system.

- For Iberdrola, the largest investor-owned Spanish electricity company, he assisted in development of their proposal for a fundamental reorganization of the electricity sector, its means of compensating generation and distribution companies, its regulation, and the phasing out of subsidies. He also has assisted the company in evaluating generation expansion options and in valuing offers for imported power.

- Dr. Hieronymus contributed extensively to a project for the Ukrainian Electricity Ministry, the goal of which was to reorganize the Ukrainian electricity sector and prepare it for transfer to the private sector and the attraction of foreign capital. The proposed reorganization is based on regional electric power companies, linked by a unified central market, with market-based prices for electricity.

- At the request of the Ministry of Power of the USSR, Dr. Hieronymus participated in the creation of a seminar on electricity restructuring and privatization. The seminar was given for 200 invited Ministerial staff and senior managers for the USSR power system. His specific role was to introduce the requirements and methods of privatization. Subsequent to the breakup of the Soviet Union, Dr. Hieronymus continued to advise both the Russian energy and power ministry and the government-owned generation and transmission company on restructuring and market development issues.

- On behalf of a large continental electricity company, Dr. Hieronymus analyzed the proposed directives from the European Commission on gas and electricity transit (open access regimes) and on the internal market for electricity. The purpose of this assignment was to forecast likely developments in the structure and regulation of the electricity sector in the common market and to assist the client in understanding their implications.

- For the electric utility company of the Republic of Ireland, he assessed the likely economic benefit of building an interconnector between Eire and Wales for the sharing of reserves and the interchange of power.

- For a task force representing the Treasury, electricity generating, and electricity distribution industries in New Zealand, Dr. Hieronymus undertook an analysis of industry structure and regulatory alternatives for achieving the economically efficient generation of electricity. The analysis explored how the industry likely would operate under alternative regimes and their implications for asset valuation, electricity pricing, competition, and regulatory requirements.

TARIFF DESIGN METHODOLOGIES AND POLICY ISSUES

- Dr. Hieronymus participated in a series of studies for the National Grid Company of the United Kingdom and for ScottishPower on appropriate pricing methodologies for transmission, including incentives for efficient investment and location decisions.

- For a U.S. utility client, he directed an analysis of time-differentiated costs based on accounting concepts. The study required selection of rating periods and allocation of costs to time periods and within time periods to rate classes.

- For EPRI, Dr. Hieronymus directed a study that examined the effects of time-of-day rates on the level and pattern of residential electricity consumption.

- For the EPRI-NARUC Rate Design Study, he developed a methodology for designing optimum cost-tracking block rate structures.

- On behalf of a group of cogenerators, Dr. Hieronymus filed testimony before the Energy Select Committee of the UK Parliament on the effects of prices on cogeneration development.

- For the Edison Electric Institute (EEI), he prepared a statement of the industry's position on proposed federal guidelines regarding fuel adjustment clauses. He also assisted EEI in responding to the U.S. Department of Energy (DOE) guidelines on cost-of-service standards.

- For private utility clients, Dr. Hieronymus assisted in the preparation both of their comments on draft FERC regulations and of their compliance plans for PURPA Section l33.

- For a state utilities commission, Dr. Hieronymus assessed its utilities' existing automatic adjustment clauses to determine their compliance with PURPA and recommended modifications.

- For DOE, he developed an analysis of automatic adjustment clauses currently employed by electric utilities. The focus of this analysis was on efficiency incentive effects.

- For the commissioners of a public utility commission, Dr. Hieronymus assisted in preparation of briefing papers, lines of questioning, and proposed findings of fact in a generic rate design proceeding.

SALES FORECASTING METHODOLOGIES FOR GAS AND ELECTRIC UTILITIES

- For the White House Sub-Cabinet Task Force on the future of the electric utility industry, Dr. Hieronymus co-directed a major analysis of "least-cost planning studies" and "low-growth energy futures." That analysis was the sole demand-side study commissioned by the task force, and it formed a basis for the task force's conclusions concerning the need for new facilities and the relative roles of new construction and customer side-of-the-meter programs in utility planning.

- For a large eastern utility, Dr. Hieronymus developed a load forecasting model designed to interface with the utility's revenue forecasting system-planning functions. The model forecasts detailed monthly sales and seasonal peaks for a 10-year period.

- For DOE, he directed development of an independent needs assessment model for use by state public utility commissions. This major study developed the capabilities required for independent forecasting by state commissions and provided a forecasting model for their interim use.

- For state regulatory commissions, Dr. Hieronymus has consulted in the development of service area-level forecasting models of electric utility companies.

- For EPRI, he authored a study of electricity demand and load forecasting models. The study surveyed state-of-the-art models of electricity demand and subjected the most promising models to empirical testing to determine their potential for use in long-term forecasting.

- For a Midwestern electric utility, he provided consulting assistance in improving the client’s load forecast, and testified in defense of the revised forecasting models.

- For an East Coast gas utility, Dr. Hieronymus testified with respect to sales forecasts and provided consulting assistance in improving the models used to forecast residential and commercial sales.

OTHER STUDIES PERTAINING TO REGULATED AND ENERGY COMPANIES

- In a number of antitrust and regulatory matters, Dr. Hieronymus has performed analyses and litigation support tasks. These cases have included Sherman Act Section 1 and 2 allegations, contract negotiations, generic rate hearings, ITC hearings, and a major asset valuation suit. In a major antitrust case, he testified with respect to the demand for business telecommunications services and the impact of various practices on demand and on the market share of a new entrant. For a major electrical equipment vendor, Dr. Hieronymus testified on damages with respect to alleged defects and associated fraud and warranty claims. In connection with mergers for which he is the market power expert, Dr. Hieronymus assists clients in Hart-Scott-Rodino investigations by the Antitrust Division of the U.S. Department of Justice and the Federal Trade Commission. In an arbitration case, he testified as to changed circumstances affecting the equitable nature of a contract. In a municipalization case, he testified concerning the reasonable expectation period for the supplier of power and transmission services to a municipality. In two Surface Transportation Board proceedings, he testified on the sufficiency of product market competition to inhibit the exercise of market power by railroads transporting coal to power plants.
- For a landholder, Dr. Hieronymus examined the feasibility and value of an energy conversion project that sought a long-term lease. The analysis was used in preparing contract negotiation strategies.
- For an industrial client considering development and marketing of a total energy system for cogeneration of electricity and low-grade heat, Dr. Hieronymus developed an estimate of the potential market for the system by geographic area.
- For the U.S. Environmental Protection Agency (EPA), he was the principal investigator in a series of studies that forecasted future supply availability and production costs for various grades of steam and metallurgical coal to be consumed in process heat and utility uses.

Dr. Hieronymus has been an invited speaker at numerous conferences on such issues as market power, industry restructuring, utility pricing in competitive markets, international developments in utility structure and regulation, risk analysis for regulated investments, price squeezes, rate design, forecasting customer response to innovative rates, intervener strategies in utility regulatory proceedings, utility deregulation, and utility-related opportunities for investment bankers.

Prior to rejoining CRA in June 2001, Dr. Hieronymus was a Member of the Management Group at PA Consulting, which acquired Hagler Bailly, Inc. in October 2000. He was a Senior Vice President of Hagler Bailly. In 1998, Hagler Bailly acquired Dr. Hieronymus's former employer, Putnam, Hayes & Bartlett, Inc. He was a Managing Director at PHB. He joined PHB in 1978. From 1973 to 1978 he was a Senior Research Associate and Program Manager for Energy Market Analysis at CRA. Previously, he served as a project director at Systems Technology Corporation and as an economist while serving as a Captain in the U.S. Army.

Exhibit E

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LG&E Energy LLC	)	**Docket No. ER06-___-000**
	)	
Louisville Gas & Electric Company, *et al*.	)	**Docket No. EC98-2-___**
	)	
Louisville Gas & Electric Company, *et al*.	)	**Docket No. EC00-67-___**
	)	
E.ON AG, *et al*.	)	**Docket No. EC01-115-___**

TESTIMONY OF VICKY A. BAILEY

Q. Please state your name and business address.

A. My name is Vicky A. Bailey. I am currently a partner in the Washington, D.C. office of the strategic legislative and public affairs consulting firm of Johnston & Associates, LLC. My business address is 2099 Pennsylvania Ave, NW, Suite 1000, Washington, D.C. 20006.

Q. Please briefly state your educational background and qualifications to testify in this proceeding.

A. I graduated with a Bachelor of Science degree from the Krannert School of Management at Purdue University, West Lafayette, Indiana and did post-graduate work at Indiana University in Indianapolis. For a period of six and one-half years, from June 1986 through May 1993, I served as a Commissioner on the Indiana Utility Regulatory Commission, which is the state regulatory body in Indiana responsible for regulation and oversight of Indiana’s investor-owned gas, electric, water, and telecommunications utilities. While serving on the Indiana Commission, I was active in the National Association of Regulatory Utility Commissioners (NARUC), where I was NARUC’s representative to the North American Electric Reliability Council’s board of trustees.

On May 10, 1993, I was nominated by President Clinton to the Federal Energy Regulatory Commission (FERC), and subsequently confirmed by the U.S. Senate, for a term ending June 30, 1996. I was re-nominated by President Clinton on June 10, 1996 and confirmed by the Senate on June 26, 1996. I continued my services as a Commissioner at FERC until February 2000.

In February 2000, I left FERC to become President of PSI Energy Inc., Indiana's largest electric supplier and the Indiana operating company of Cinergy Corp. On June 5, 2001, I was nominated by President Bush to serve as Assistant Secretary for the Office of Policy and International Affairs at the U.S. Department of Energy, a position I held until March 2004.

Following my tenure at the Department of Energy, I joined Johnston & Associates, which is a strategic public and legislative affairs consulting group formed by former Senator Bennett Johnston of Louisiana. Currently, I work on various international and domestic energy policy, regulatory, and strategic planning issues for a diverse group of clients.

Q. What is the purpose of your testimony today?

A. The purpose of my testimony is to review the core components of the MISO-withdrawal proposal being submitted herewith by Louisville Gas and Electric Company and Kentucky Utilities, Inc. (“LG&E/KU”) against the Commission’s open, nondiscriminatory access policy goals set forth in Order Nos. 888, 889 and 2000, and explain the basis for my conclusion that the LG&E/KU proposal is consistent with and meets those goals. Drawing on my expertise as both a former FERC Commissioner and a former state commissioner, I will explain why I believe that the LG&E/KU proposal, developed to meet the needs of a vertically integrated utility with very low-cost power supply that operates in a non-retail choice state, is an appropriate framework to satisfy both FERC's and Kentucky's regulatory missions.

Review of FERC Policy

Q. As a Commissioner with FERC from 1993 to 2000, did you help establish FERC policies regarding competition, open access, and reliability in the electricity industry?

A. Absolutely. During my tenure at FERC, I worked with my colleagues to establish and implement FERC policies regarding competition, open access, and reliability in the electricity industry. While at FERC, my work on these issues culminated, for example, in FERC's 1996 landmark Order Nos. 888 and 889. These directives were designed to increase competition and deregulation in the electric energy market. A foundation for the establishment of these rules was our finding that electric utilities were vertically integrated, owning generation, transmission, and distribution facilities and selling these services as a bundled package to wholesale and retail customers in a limited geographical service area. We expressed concern that public utilities were using their monopoly control over interstate transmission facilities to gain advantage over potential competitors for sales of energy. Addressing these concerns, Order No. 888 mandated that the wholesale transmission of electric energy be unbundled from the sale of power and required utilities to file open access nondiscriminatory transmission service tariffs that contain standardized minimum terms and conditions applicable to the provision of nondiscriminatory wholesale transmission services. In addition, Order No.888 provided that if state commissions order unbundling of retail transmissions, open access requirements apply to unbundled retail transmission service as well. Order No. 889

implemented standards of conduct and informational posting procedures for service providers in furtherance of the Commission's nondiscrimination policies.

Open access is the essence of Order Nos. 888 and 889 and as an advocate of the efficiency of free markets, I was, and am, a strong supporter of these orders. By requiring utilities to transmit competitors' electricity on terms and conditions comparable to transmission they afford their own wholesale power sales, open access transmission increases competition from alternative power suppliers, giving consumers the benefit of a competitive market.

Although I left the Commission shortly after the issuance of Order No. 2000 and did not vote on the final rule, I worked closely with my fellow Commissioners on its development as well as the development of Commission policies that ultimately became the basis for Order No. 2000. Order No. 2000 advanced the formation of RTOs in response concerns about engineering and economic inefficiencies in the current transmission grid and opportunities for transmission owners to discriminate to favor their own activities. I continued to oversee competition, open access and reliability issues at FERC until my departure.

Q. What concerns, if any, did FERC have regarding the status of the electricity industry that led to the issuance of Order Nos. 888 and 889?

A. The Commission was concerned in the time leading up to the issuance of Order Nos. 888 and 889 with the continuing potential for transmission owners to grant preferential treatment for transmission provided to their own or affiliated generation sources over third party sources. Because of technological and business changes, electricity consumers could have the option to purchase power from distant locales or from sources other than those owned or affiliated with the transmission provider –- but only if that third-party generator had the ability to obtain transmission service. The Commission's open access and OASIS rules were designed to promote the availability of transmission access for wholesale power transactions on a non-discriminatory basis on terms identical to those provided the transmission provider's own generation.

Given the context of LG&E's proposal, it is significant that the goal of lower consumer electricity prices (a result we identified as the product of robust competition) was the primary basis of Order Nos. 888 and 889. As we stated in Order No. 888: "Non-discriminatory open access to transmission services is critical to the full development of competitive wholesale generation markets and the lower consumer prices achievable through such competition."

Q. Can you please summarize the specific provisions of Order No. 888 that were established to achieve the goal of enhanced competition and consequent lower consumer electricity prices?

A. The issuance of Order No. 888 was a watershed event for the electricity industry. First and foremost, Order No. 888 required a transition from the traditional, closed system in which only the utility's own power was transmitted to a utility that provided non-discriminatory open access transmission services. Specifically, our regulations required utilities to (1) take transmission services under the same tariff that applies to others; (2) state separate rates for wholesale generation, transmission, and ancillary services; and (3) rely on the same electronic information network that its transmission customers rely on to obtain information about the transmission system when buying or selling power. Utilities subject to the rule filed open access transmission tariffs ("OATTs") and specific plans to address transition issues. We also discussed in Order No. 888 the potential importance and effectiveness of regional transmission entities, such as independent system operators, but we did not develop policies dealing with these types of entities.

Q. Were these same policies embodied in Order No. 889?

A. Although Order No. 889 concentrated more on ensuring transparency and compliance with open access requirements by requiring utilities to maintain and continually update Open Access Same-Time Information Systems ("OASIS"), the same policies in Order 888 underlie Order 889. The rule also required that utilities comply with standards of conduct to prevent employees of the utility or its affiliates engaging in wholesale power marketing functions from obtaining preferential access to transmission information.

Q. What led to the issuance of Order No. 2000?

A. My view is that Order No. 2000 is a continuation and enhancement of the successful competitive market reforms that the Commission embraced in Order Nos. 888 and 889. The Commission noted that the industry had, largely, successfully adapted to Order Nos. 888 and 889 and that customers had clearly and substantially benefited from open access. However, having had the benefit of experience of operating under Order No. 888 for a number of years, the Commission saw that certain improvements to the competitive underpinnings of the industry could be made.

Most importantly, the Commission had growing experience with and confidence in regional entities, such as ISOs and RTOs, as a means by which the potential for undue discrimination by utilities amongst transmission customers could be minimized. The Commission recognized that the increased reliance on non-utility generation sources (which Order Nos. 888 and 889 unabashedly encouraged) placed stresses on the electricity grid that were essentially regional in character. The Commission found, as Order No. 2000 put it, that because of the beneficial changes occasioned by Order Nos. 888 and 889, "the transmission grid is now being used more intensively and in different ways than in the past." The Commission feared that, because of the rapidity of these substantial changes to grid operations, transmission construction and planning were not adapting fast enough to keep up with the stresses put on the grid.

Thus, the Commission saw a need to both carry further the competitive spirit in Order Nos. 888 and 889 and to address reliability concerns occasioned by the transition to open access to transmission.

Q. How did the Commission address these concerns in Order No. 2000?

A. By far the most significant enhancements in Order No. 2000 were the embrace of the creation of third-party regional transmission entities that could independently administer and operate transmission systems. The Commission's support for these sorts of regional entities grew gradually, based upon its own experience after Order No. 888, ongoing conversations with state commissions and industry stakeholders, and the extensive comment process preceding the issuance of Order No. 2000. Regional entities could more easily address economic and engineering inefficiencies, addressing reliability concerns on a regional basis while promoting greater competition among those seeking to utilize transmission assets. The rule set forth specific requirements for RTOs and procedures for RTO approval.

RTO Membership

Q. Did FERC require utilities to become members of RTOs in Order No. 2000?

A. No, the Commission specifically rejected the idea of mandatory RTO membership for several reasons. To this end, the Commission adopted a very flexible approach under which utilities could voluntarily seek to join RTOs or other regional entities, if they and the Commission deemed such membership beneficial. My colleagues stated that "[g]iven the rapidly evolving state of the electric industry, we want to allow involved participants the flexibility to develop mutually agreeable regional arrangements with respect to RTO formation and coordination." The Commission wanted to "act as a catalyst" in the discussions leading to RTOs, but did not believe that RTO membership was a flat prerequisite to the provision of just and reasonable, non-discriminatory transmission service. I strongly agreed with my colleagues, and continue to believe, that RTO membership is not the only means by which effective competition and reliable transmission operations can be ensured.

Q. After the issuance of Order No. 2000, was it ever the Commission's policy that membership in an RTO would be mandatory?

A. No, I don't believe the Commission has ever mandated RTO membership, per se, though it has conditioned certain mergers of electric utilities on their execution of plans to join an RTO as a way to ensure that competition would not be adversely affected by the merger. While the Commission considered the possibility of more expansive RTO participation as part of its Standard Market Design initiative, that initiative has been significantly scaled back, if not abandoned entirely.

Q. As a matter of policy, do you believe that all utilities should be compelled to become RTO members?

A. No, I do not. Although I strongly supported Order No. 2000 and the RTO concept, I believed then and believe now that RTO membership should be voluntary; RTOs may serve to maintain reliability while lowering consumers' costs in some cases, but not in *all* cases. I do not believe that RTO membership should be mandated for the industry, and I agree with the Commission's current policies in this regard. There are many ways (and perhaps some ways that the Commission has not yet contemplated) that utilities can provide the same, or greater, levels of assurance that they are permitting robust competition and ensuring reliability on their transmission systems other than by becoming members of RTOs. Order No. 2000 acknowledges this. Throughout my professional career, I have been a proponent of allowing innovative compliance with regulatory policies where such compliance can be shown to be consistent with, or superior to, regulators' policies and standards. Order Nos. 888, 889, and 2000 were steps to enhance reliability and competition in the industry while allowing sufficient flexibility for the Commission, utilities, and market participants to address issues and solutions on utility-specific bases. This was, and is, a sound regulatory approach.

Q. Did LG&E and KU ever offer to join an RTO?

A. LG&E and KU indicated to the Commission at the time of their proposed merger their intent to become part of the Midwest ISO, and that the Commission relied on this commitment in its approval of the merger. In addition, their Midwest ISO membership plans were referenced again as a premise for the Commission's approval of a subsequent merger involving these utilities' parent company. The reliance by the Commission on RTO membership as a premise for its merger approval was consistent with the Commission's goal to foster RTO development and similar to its analysis taken in other merger cases that had come before it since the promulgation of Order No. 2000.

Q. Why did RTO commitments and conditions become customary in merger proceedings?

A. RTO commitments became a way by which applicants could easily demonstrate their mitigation of potential market power that could result from the merger transaction. Often, applicants appeared to tender RTO commitments to receive timely Commission approval, even though the commitments went well beyond any competitive harm that may have been created by the merger. And it is certainly true that RTOs can be an effective way to mitigate market power; however, RTO membership is not always necessary or appropriate to mitigate an increase in market power caused by a merger.

LG&E/KU's ITO/RC Proposal

Q. Have you had an opportunity to review the LG&E/KU proposal to have their systems administered by an ITO and reliability functions controlled by a Reliability Coordinator?

A. Yes, I have.

Q. In your opinion, does LG&E/KU's proposal satisfactorily comply with Order Nos. 888, 889, and 2000?

A. Yes. Essential to my opinion are four aspects of the proposal. First, LG&E/KU propose to terminate existing membership in the Midwest ISO and instead permit two independent entities to operate and maintain the reliability of their systems. LG&E/KU would invest authority to manage transmission functions currently handled by Midwest ISO in an ITO, the Southwest Power Pool. Second, the companies would grant similar authority over reliability issues and management to the chosen Reliability Coordinator, TVA. Third, LG&E/KU have attempted to ensure the independence of these entities in a manner consistent with Order No. 2000 and other Commission precedent. Fourth, they have also addressed continuing compliance with the open access and posting requirements of Order Nos. 888 and 889.

Q. Do you believe that the ITO/RC proposal meets the objective of LG&E/KU's merger commitments?

A. As a former FERC commissioner who voted on LG&E's merger with KU, I can confidently recommend that the ITO/RC should be deemed to meet the objective of the company's merger commitments. I supported LG&E and KU's RTO membership merger commitment in order to mitigate any potential market power their merger might have created, not to mandate LG&E/KU's RTO membership indefinitely *per se*. That this was the Commission's view of the merger commitment is clear from the language we used in drafting the order approving LG&E and KU's merger:

> If LG&E and KU seek permission to withdraw from the Midwest ISO proceedings or the ISO once it is operating, we will evaluate that request in light of its impact on competition in the KU destination markets….[1]

With that background in mind, LG&E/KU's proposal provides for an independent Reliability Coordinator and an independent administrator of LG&E/KU's transmission system and tariff. This formulation goes well beyond the open access and competitive goals Order Nos. 888, 889, and 2000; indeed, I agree with LG&E/KU's observation that, taken together, the functions of the Reliability Coordinator and the ITO are essentially identical to the Midwest ISO's Commission-approved Day 1 operations. Thus, because the Midwest ISO Day 1 proposal constituted satisfactory compliance with the merger orders, the ITO/RC proposal, which provides the same functions and independence as did the Midwest ISO in Day 1, should be satisfactory today.

Q. Why should the Commission not simply require LG&E/KU to remain in an RTO indefinitely?

[1] *Louisville Gas & Elec. Co.*, 82 FERC ¶ 61,308 (1998).

A. As the language from the Commission's LG&E and KU merger order I quoted above shows, the Commission clearly contemplated that LG&E/KU might one day withdraw from the Midwest ISO in favor of another approach to further the Commission's policies. Thus the Commission should not place form over substance and require LG&E/KU to remain in an RTO *ad infinitum* because the RTO construct, although the optimal solution in certain situations, is not a panacea.

Q. In considering LG&E/KU's proposal, what issues did you analyze that you believe the Commission should consider when evaluating LG&E/KU's proposal?

A. In evaluating LG&E/KU's ITO/RC proposal, I considered the following issues, which I recommend the Commission consider as well. First and foremost, the Commission should determine whether the proposal is consistent with, and meets the regulatory goals embodied in, Order Nos. 888, 889, and 2000. Particularly, the Commission should consider the following issues:

- What is the impact on open access and the provision of nondiscriminatory transmission service by the proposal?
- How does the proposal impact reliability?
- What is the effect of the proposal on the efficiency of the grid and the provision of service? This would include considerations of rate pancaking, facilitation of regional transactions, and, most importantly, the bottom line price for delivered energy to consumers.
- What is the overall impact on market participants, including customers inside and outside the LG&E/KU delivery area and transmission customers in the region?

Q. Do you believe that LG&E/KU's proposal satisfactorily addresses these issues?

A. Yes, I do. I understand that LG&E/KU have concluded that their continued membership in the Midwest RTO is not in the best financial interest of their customers or their own companies, and further that their companies' departure from the Midwest ISO will not harm other market participants. The proposal appears to be an innovative way to ensure continued compliance with the Commission's regulations while offering equivalent or superior efficiency and reliability than continued membership in the Midwest ISO.

Q. How did you come to this conclusion?

A. There are some threshold considerations that inform my opinion and that I suggest should likewise inform the Commission's evaluation of LG&E/KU's proposal. First, the Commission has specifically adopted regulations through the Order Nos. 888, 889, and 2000 rulemakings with which all jurisdictional utilities must comply. Second, as I have already discussed, it is important to remember that RTO membership is not required for any utilities, including LG&E and KU, under the Commission's policies. Third, FERC policy recognizes the need to accommodate regional differences and accommodation and coordination with state regulators. The Commission has, wisely in my opinion, charted a flexible course when evaluating utilities' compliance with Commission policy. LG&E/KU and its state regulator, the Kentucky Public Service Commission, should be accorded this flexibility. Fourth, specifically concerning membership in the Midwest ISO, and more generally looking at RTO membership in the industry, the Commission has accepted RTO agreements that explicitly permit - and provide frameworks for - member utilities to withdraw. The Midwest ISO agreement contains such a provision and LG&E/KU will need to meet their contractual obligations in this regard. These exit provisions presumably mitigate or eliminate any adverse effects to an RTO of a member's withdrawal. And, fifth, the Commission's merger orders acknowledge RTO participation as part of its traditional analysis under Section 203 of the Federal Power Act. LG&E/KU witness William Hieronymous addresses merger orders that affect LG&E and KU in this proceeding and the Commission should consider that testimony in this regard.

Q. While describing Order No. 2000, you mentioned that the independence of the transmission operator was a key consideration in the final rule. What constitutes "independence" as that concept was articulated by the Commission in Order No. 2000?

A. Independence, the first of the minimum characteristics of an RTO identified in Order No. 2000, is a prerequisite for RTO status. Independence is necessary so as to eliminate any bias or financial interest that the operator of the grid would have in transmission-related decision making. In Order No. 2000, the Commission identified three specific aspects of independence that had to be satisfied for an entity to be a qualified RTO: (1) the entity, its employees, and its non-stakeholder directors must not have a financial interest in any market participant; (2) the entity must have a decision-making process that is independent of the utility or any market participant; and (3) the entity must have the authority to file changes to the governing tariff.

I also note that, in addition to independence, Order No. 2000 adopted certain other standards by which a prospective RTO would be judged. These included the ideas that a regional entity would need to be of sufficient scope and configuration so as to permit it to efficiently operate the grid, it must have sufficient operational authority to manage the grid, and it must have authority and responsibility to manage short-term reliability issues.

Based on the testimony of others in this proceeding, it appears that LG&E/KU have divided these responsibilities and characteristics between the ITO and Reliability Coordinator to the same extent as these functions were managed by Midwest ISO.

Q. How will the ITO and Reliability Coordinator for the LG&E/KU systems meet the standards for independence articulated in Order No. 2000?

A. LG&E witness Mark Johnson testifies in some depth regarding the independence of both the ITO and the Reliability Coordinator. The particular aspects of independence of the ITO and Reliability Coordinator are described in Mr. Johnson's testimony and I will not repeat them in full here. However, based on my review of his testimony and LG&E/KU's proposal, it appears that many of the indicia of independence adopted by the ITO and Reliability Coordinator parallel what is currently required for RTOs. The ITO and Reliability Coordinator will not be affiliated with stakeholders and employees of the two entities will not also be employed, controlled by, or have a financial interest in stakeholders. Employees of the ITO and Reliability Coordinator that perform transmission functions will be treated as transmission function employees for purposes of LG&E's and KU's Standards of Conduct. The two entities will independently have the ability to collect and analyze data about the LG&E/KU systems. The ITO will administer and have authority to propose modifications to the applicable OATT. These factors are strong evidence that the ITO and Reliability Coordinator will be truly independent of LG&E/KU control and will be able to make transmission and reliability decisions on a non-discriminatory basis. Taken together, these factors would also seem to be consistent with the requirements of "independence" as described in Order No. 2000.

Q. Will the LG&E/KU proposal allow for continued compliance with Order No. 889?

A. Yes. LG&E/KU explain that SPP will be responsible for and will have full authority to meet the OASIS posting and other requirements of Order No. 889, and the pro forma ITO Agreement embodies these obligations.

Q. You have mentioned reliability as being a key consideration for the Commission in this proceeding. Could you please expand on this point?

A. Reliability, obviously, is a key consideration in many Commission decisions. The Commission is charged with the duty to ensure that the interstate grid is sufficiently reliable. In this case, the Commission should address any reliability concerns both within LG&E's and KU's systems as well as in the larger region associated with the proposal. The Commission could content itself on this score by reviewing the functions of the Reliability Coordinator, TVA, and the competency of TVA to perform these functions.

Q. Will reliability be harmed under the LG&E/KU proposal?

A. Reliability does not appear to be harmed, and may in fact be enhanced by the proposal. TVA appears to be quite competent and the functions and authority granted to the Reliability Coordinator seem commensurate to the reliability functions that the Midwest ISO has been performing.

Q. You have also mentioned efficiency of the interstate market as an issue that the Commission should consider in this proceeding. Has LG&E/KU identified aspects of their proposal that address efficiency concerns?

A. Yes. Specifically, LG&E/KU point to the fact that rate pancaking will not result from the proposal and that seams issues will be addressed on mutually agreeable terms with adjoining systems' operators. The companies propose a Rate De-Pancaking Plan that mimics transmission protocols adopted by the Midwest ISO and PJM. The goal, as explained by LG&E/KU, is to ensure that there are no economic seams created as a result of the proposal. Details concerning rate de-pancaking and seams between LG&E/KU and adjoining systems are contained in the transmittal letter accompanying the companies' filing.

Q. You have mentioned that your background as a FERC Commissioner and as a Commissioner with the Indiana commission inform your opinions about LG&E/KU's proposal. Overall, based on your state and federal regulatory experience, does LG&E/KU's ITO/RC proposal strike the optimal balance between achieving federal and state policy goals?

A. Yes, it does. It is important that state commissions and FERC to work together to ensure efficient operation of the transmission grids in the nation. Both state public utility commissions and FERC should be receptive to each other's points of view and, where possible, accommodating. LG&E/KU's proposal, if implemented, would appear to lower consumers' bills in Kentucky. That is a very substantial consumer interest that state regulators in Kentucky, entirely understandably, may choose to promote. And, it is an interest to which the Commission should be sensitive.

Of course, the Commission's primary charge is to ensure efficient, reliable interstate transmission and it is not always possible to reconcile this goal with a state commission's or consumers' interest. Where, however, a state's consumers would benefit from a utility's proposal, the FERC should attempt to strike a balance between the federal interest and the state's. Put another way, if the efficiency and reliability of the interstate grid or interstate market is not negatively impacted by a proposal that would assist a utility's ultimate consumers, the Commission should apply its policies and regulations flexibly so as to permit the proposal. I have been on both sides of this balancing act, as both a state public utility commissioner and a FERC Commissioner. And, by and large, I believe that the Commission embraces this philosophy.

It is with this philosophy of flexibility in mind that the Commission should review LG&E/KU's proposal.

Q. Overall, how do you assess the effect of LG&E/KU's proposal on stakeholders?

A. From a public policy perspective, it is most helpful to look to the effect of a proposal on the various individual constituencies. As I have explained, it appears that existing market participants in the Midwest ISO will not be harmed by LG&E/KU's departure and that substantial benefits accrue to LG&E's retail customers. In this circumstance, where no one is harmed by the proposal and a large group of constituents is significantly helped, the Commission would be well-served by permitting the proposal to move forward.

Q. What is your recommendation?

A. I recommend that the Commission approve LG&E/KU's application concerning the proposed ITO/RC construct. The Commission's established policy objectives contained in Orders 888, 889, and 2000 will not only be met but advanced by consideration of alternative approaches such as the ITO/RC alternative that LG&E/KU proposes. Achievement of these policy objectives can best be achieved by flexible approaches that reflect the distinctive circumstances in which particular entities find themselves. The unique circumstances in Kentucky and FERC's policy objectives are best met through the approval of LG&E/KU's application.

Q. Does this conclude your testimony?

A. Yes.

VERIFICATION

DISTRICT OF COLUMBIA	)))	**SS:**

The undersigned, Vicky A. Bailey, being duly sworn, deposes and says she is partner in the Washington, D.C. office of Johnston & Associates, LLC, that she has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of her information, knowledge and belief.

Vicky A. Bailey
VICKY A. BAILEY

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 6th day of October 2005.

Laura J. Kalanewich
Notary Public

My Commission Expires:
My Commission Expires November 14, 2005
____

Exhibit F

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LG&E Energy LLC	**)**	**Docket No. ER06-___-000**
	)	
Louisville Gas & Electric Company, *et al*.	**)**	**Docket No. EC98-2-___**
	)	
Louisville Gas & Electric Company, *et al*.	**)**	**Docket No. EC00-67-___**
	)	
E.ON AG, *et al*.	**)**	**Docket No. EC01-115-___**

TESTIMONY OF MARK S. JOHNSON

Q. Please state your name and business address.

A. My name is Mark S. Johnson. I am currently employed as Director, Transmission for LG&E Energy Corporation. LG&E Energy Corporation is the parent company of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU"), the applicants in this proceeding. My business address is 220 West Main Street, Louisville, KY 40202.

Q. Please briefly state your educational and professional background.

A. I have over 25 years of experience in the utility industry. I have held senior leadership positions at LG&E Energy Corp., Tennessee Valley Authority, and Entergy. From January, 2001 to the present, I have served as the Director, Transmission, LG&E Energy Corporation. In this position, I am responsible for the design, engineering, planning, operations and maintenance of the enterprise's transmission system. From November 1997 to January 2001, I was a Director, in Distribution Operations for LG&E Energy Corp.; my responsibility was to ensure the safe and reliable delivery of service to the customer. From February 1987 to November 1997, I was employed by the Tennessee Valley Authority. There I held a number of senior level positions in the Power

Generation, Transmission, Customer Service and Marketing. Most notably I was the Area Vice President, Transmission, Customer Service and Marketing for three and one half years. From January 1985 to February 1987, I was employed by Entergy at the Grand Gulf Nuclear Generation Station as the Manager, Engineering Support. From May 1980 to January 1985, I was employed by the Tennessee Valley Authority at the Watts Bar Nuclear Generating Station as the Manager, Document Control and Configuration Management. I received my Bachelor of Science degree in Civil Engineering Technology from Murray State University in 1980.

Q. Can you expand upon your current employment duties?

A. I am responsible for the oversight of functions related to transmission reliability, planning and expansion for LG&E and KU. I oversee the development and analysis base cases for the companies footprint used today by the Midwest ISO ("MISO") in power flow analyses and electricity models, stability analyses, Available Transfer Capability ("ATC") calculations, and reliability criteria compliance. My responsibilities also include the oversight review of studies and analysis for transmission service and generation interconnection requests in coordination MISO as required. Recently, I have actively participated in the process to choose for LG&E/KU an Independent Transmission Organization ("ITO") to perform key transmission-related functions and a Reliability Coordinator to manage reliability functions for LG&E's and KU's transmission systems.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony is twofold. First, I will describe the process by which a Reliability Coordinator was chosen and an ITO will be chosen by LG&E/KU.

LG&E/KU issued requests for proposals ("RFPs") for both an ITO and Reliability Coordinator in which specific requirements and functions for the two entities were described. After consideration of the responses received, LG&E/KU selected the Tennessee Valley Authority ("TVA") as their Reliability Coordinator and the Southwest Power Pool ("SPP") as their ITO.

Second, I will explain the fundamental characteristics and functions of both the ITO and the Reliability Coordinator. LG&E/KU are confident that both of these entities will satisfy the Federal Energy Regulatory Commission's ("FERC") independence requirements – they will not be affiliated with, nor take direction from LG&E/KU and will be functionally separated from all other market participants. The ITO will conduct all transmission scheduling (including calculation of available transmission and awarding of transmission service to customers), administer the LG&E/KU OATT and OASIS, and control all generation interconnection determinations, among other functions. The Reliability Coordinator will perform security coordination consistent with NERC guidelines, have authority to approve or deny maintenance schedules for the LG&E/KU systems, and act as the transmission planning authority for the systems (including reviewing and determining the need for expansions and upgrades, approving planning criteria, and conducting reliability assessments). A representative of TVA is also submitting testimony in this proceeding describing our proposed Reliability Coordinator's capabilities.

Both the ITO and Reliability Coordinator will exchange information and cooperate to ensure that both entities can perform their assigned functions. The application contains a matrix which highlights the functions of each entity, and communications and coordination protocols.

Q. You mentioned your involvement in the RFP process for both an ITO and a Reliability Coordinator for the LG&E/KU systems. Can you describe this process?

A. Yes. I was involved in all steps of the two, separate RFPs to select an ITO and a Reliability Coordinator. I assisted in the drafting of the language of the RFPs, including the listed functions of the ITO and Reliability Coordinator. On August 10, 2005, LG&E/KU submitted an RFP for the Reliability Coordinator's position to MISO, TVA, SPP and PJM.. Responses to the RFP were due on August 24, 2005. There were only two respondents to the RFP. On August 30, 2005, LG&E/KU selected TVA as the reliability coordinator for their systems and on September 27, 2005, the parties executed a Letter of Intent. The parties anticipate negotiating a mutually acceptable Reliability Coordination Agreement to be executed on or before April 1, 2006.

LG&E/KU's ITO RFP was distributed on August 22, 2005. As with the RFP for the Reliability Coordinator, LG&E/KU submitted the RFP to a number of potential entities that could provide the needed services. The RFP were submitted to SPP, PJM, MISO, New York ISO, ISO New England, ERCOT, and the California ISO. Responses to the RFP for an ITO were due on September 8, 2005. SPP was the only respondent. SPP and LG&E/KU are currently in negotiations on an ITO agreement. The parties plan to also conclude negotiations on mutually acceptable terms on or before April 1, 2006.

Q. What were the reasons that LG&E/KU selected TVA to be the Reliability Coordinator for their systems?

In addition to being lowest cost respondent, TVA as a governmental entity with its own stringent Code of Conduct prohibiting favoritism in the conduct of transmission functions has a unique claim to independence from other private sector market participants. TVA has substantial operational experience in the power industry. In addition, TVA is prohibited by federal legislation (with some small exceptions) from marketing its power outside of the TVA footprint and, thus, will not be a power sales market participant outside of this footprint.

I would also point out that TVA already acts as the Reliability Coordinator for BREC and EKPC, systems that adjoin the LG&E/KU systems. Once TVA becomes the Reliability Coordinator for the LG&E/KU systems, TVA will be positioned to manage reliability over a Reliability Area that encompassed most of Kentucky. TVA's expertise with the BREC and EKPC systems and the region were seen as substantial benefits that certainly influenced LG&E/KU's decision to engage TVA as its Reliability Coordinator.

TVA also has in place an operational seams agreement with MISO and PJM. This is critical because were LG&E/KU to obtain reliability coordination services from an entity not party to that JOA, LG&E/KU would have to develop individualized seams agreements with each adjacent control area. While any of the three NERC-certified Reliability Coordinators who are parties to the existing MISO-PJM-TVA JOA could fold LG&E/KU into the market(s) to non-market seams arrangement set forth in the JOA, TVA was the only one of the three to respond to the LG&E/KU RFP.

In addition to demonstrating a core competency and a contractual arrangement to handle reliability coordination issues in the region, TVA meets all of the criteria regarding independent operation, and met all of the numerous other requirements outlined in the RFP.

Finally, as I earlier alluded to, TVA proposed to perform the functions of Reliability Coordinator at a rate that was very competitive and would offer the most economic benefit to LG&E/KU's retail customers.

LG&E/KU are confident that TVA will be an excellent Reliability Coordinator.

Q. What factors led LG&E/KU's to select SPP as their ITO?

A. We selected SPP as the ITO essentially utilizing the same factors as we chose a Reliability Coordinator. Namely, LG&E/KU wanted to ensure that the ITO can: (i) competently perform the functions required of it, as described in the RFP; (ii) meet all other requirements listed in the RFP, especially those related to their independence from other market participants and (iii) provide substantial value to LG&E/KU's customers through a competitive rate for the service it provides.

While SPP was the only entity to respond with a proposal in response to the ITO RFP, the response was very reasonable when compared to, for example, the arrangement between Duke and the Midwest ISO, which generally provides for the same types of tariff administration services. SPP is quite competent to perform the duties required of the ITO and is willing to perform all of those duties and sees provision of these unbundled services as a win-win for both LG&E/KU and SPP's existing membership. SPP already has in place the personnel and infrastructure needed to perform the transmission function duties needed and, most importantly, has substantial experience in transmission operations. SPP has offered to provide ITO service to LG&E/KU at a very competitive rate.

Q. You have mentioned "independence" as a key requirement for both an ITO and a Reliability Coordinator. What do you mean by "independence" and why is it important?

A. Having an ITO and Reliability Coordinator that are independent of market participant control is a cornerstone of LG&E/KU's proposal. Stakeholders, and the FERC, must be able to trust that the decisions made by the ITO and Reliability Coordinator are made free of any bias or financial interest of the entity making the decision. One of the primary ways to demonstrate that such trust is appropriate is to require that the decision making entity not be affiliated with market participants, that it be responsive to all transmission customers, and that its decision making processes be appropriately transparent. LG&E/KU believe that demonstrated independence of both the ITO and RC goes a long way in addressing many of the concerns FERC has identified in the recent NOI on revisions to Orders 888 and 889. FERC precedent includes policies and requirements that are used to determine whether entities are independent in this fashion and LG&E/KU have developed the present proposal to ensure that the ITO and Reliability Coordinator meet these requirements.

Q. How are LG&E/KU ensuring that the ITO and Reliability Coordinator are, in fact, independent?

A. Both the RFPs for each entity and the agreements that the selected ITO and Reliability Coordinator must execute with LG&E/KU contain requirements that will ensure independence.

Q. What requirements will be imposed on the ITO to ensure its independence?

A. Through the requirements contained in the existing RFP and pro forma ITO Agreement, the ITO must not be affiliated with LG&E, KU, or any market participant. Likewise, as LG&E and KU described in the RFP, any potential ITO must strictly meet specified criteria during the RFP process, and on a going forward basis, to demonstrate its independence. Section 2 of the pro forma ITO Agreement provides, for example, that employees and agents of the ITO shall not also be employed by LG&E or KU and shall remain outside of the control of LG&E, KU, any affiliates of the companies, or any market participant. Employees and agents of the ITO will divest any direct security interest in LG&E or KU within six months of being assigned transmission function responsibilities. Employees and agents of the ITO will have separate office space from LG&E/KU transmission/reliability or merchant personnel and access to ITO employee workspaces will be controlled consistent with the FERC's Standards of Conduct regulations.

All employees of the ITO that perform ITO functions shall be treated as LG&E/KU transmission function employees for purposes of LG&E's and KU's Standards of Conduct, including prohibitions against information sharing with any LG&E/KU Energy or Marketing Affiliate employees. The ITO is to function as an independent contractor, with the ability to separately collect and analyze transmission data and submit reports to governmental authorities on its own initiative. LG&E/KU may cancel the ITO Agreement before the Initial Term only upon FERC approval, subject to specific findings made by FERC, or where one party is guilty of gross negligence, willful misconduct, or fraud. These termination provisions further protect the ITO's ability to perform its functions without fear of interference.

Based on SPP's response to the ITO RFP, we are very confident that SPP is capable of administering transmission service for LG&E/KU system in an independent, non-discriminatory manner. The requirements and provisions I have discussed are designed to reinforce the ITO's independence.

Q. Are similar requirements in place to ensure the independence of TVA as the Reliability Coordinator?

A. Absolutely. TVA meets all of the independence requirements listed in the Reliability Coordinator RFP and the executed Reliability Coordinator Agreement. TVA is not affiliated with any market participant. Employees and agents of TVA will not be employed by LG&E or KU and will remain outside of the control of LG&E, KU, any affiliates of the companies, or any market participant. Employees and agents of TVA will divest any direct security interest in LG&E or KU within six months of being assigned transmission function responsibilities. Employees and agents of TVA will always have separate office space from LG&E/KU transmission/reliability or merchant personnel and access to TVA employee workspaces will be controlled consistent with the FERC's Standards of Conduct regulations. All employees of the Reliability Coordinator that perform transmission functions shall be treated as LG&E/KU transmission function employees for purposes of LG&E's and KU's Standards of Conduct, including prohibitions against information sharing with any LG&E/KU Energy or Marketing Affiliate employees. TVA will be an independent contractor to LG&E/KU, with the ability to separately collect and analyze transmission data and submit reports to governmental authorities on its own initiative.

Additionally, TVA is itself a governmental entity with separate restrictions on its affiliations with other market participants, as I discussed above. These restrictions provide further assurances, beyond those in the Reliability Coordinator agreement, that the TVA will truly be independent from control by market participants.

Q. Put simply, what role will the ITO play in the operations of the LG&E/KU systems?

A. The ITO will be responsible for, and have the authority necessary to carry out, management of transmission service on the LG&E/KU systems. The ITO will be the single contact for transmission customers seeking to schedule transactions on the LG&E/KU systems and will make all decisions relating to allocation of transmission service to customers. The specific functions of the ITO are described in the ITO RFP and the pro forma ITO Agreement.

Q. What are some of the specific functions of the ITO?

A. As the relevant RFP and pro forma agreement provide, SPP will take over many of the same transmission functions currently performed for LG&E/KU by the Midwest ISO. The ITO will have complete authority, and an obligation, to administer the terms and conditions of LG&E/KU's FERC-approved OATT. The ITO will have the authority and obligation to administer the LG&E/KU OASIS, including the responsibility to update and post information to ensure compliance with all FERC OASIS-related regulations.

SPP also will evaluate all transmission service requests, including requests for network service and existing point-to-point service agreements. The ITO will maintain all of the appropriate documentation associated with transmission determinations. As with all other functions managed by the ITO, transmission requests must be evaluated on a non-discriminatory basis. In addition, the ITO will be the clearinghouse for customers' questions regarding transmission and scheduling. The ITO will act as the scheduling coordinator for all transmission transactions into, out of, or through the LG&E/KU transmission systems.

The ITO will also conduct all System Impact Studies ("SIS") and Facilities Studies as may be required under the OATT when transmission service is requested. The ITO has the option of coordinating with LG&E and/or the Reliability Coordinator personnel to the extent that it wishes assistance in performing such studies. LG&E has the right to review and provide comment on studies, but the ITO has ultimate authority to determine the impact of service requests on the system and required upgrades. The ITO will calculate ATC and TTC in accordance with the FERC-approved OATT. ATC will be calculated on a control area basis for LG&E/KU's control area interfaces.

With regard to generator interconnection, the ITO will process all requests by generators and will perform such studies as warranted by the OATT and the interconnection standards contained therein. This authority includes the ability to manage the interconnection queue and establish a system model to evaluate requests for interconnection.

Q. Does this conclude your testimony at this time?

A. Yes.

VERIFICATION

COMMONWEALTH OF KENTUCKY)
) SS:
COUNTY OF JEFFERSON)

The undersigned, **Mark S. Johnson**, being duly sworn, deposes and says he is the Director, Transmission for LG&E Energy Corporation, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

MARK S. JOHNSON

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 5th day of October 2005.

Edward J. Stottmann
Notary Public

My Commission Expires:
Notary Public, State at Large, KY
My commission expires Sept. 25, 2007

Exhibit G

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LG&E Energy LLC	)	**Docket No. ER06-___-000**
	)	
Louisville Gas & Electric Company, *et al*.	)	**Docket No. EC98-2-___**
	)	
Louisville Gas & Electric Company, *et al*.	)	**Docket No. EC00-67-___**
	)	
E.ON AG, *et al*.	)	**Docket No. EC01-115-___**

<u>TESTIMONY OF STUART L. GOZA</u>

Q. Please state your name, business address, and current position.

A. My name is Stuart L. Goza. I am the reliability coordinator for the Tennessee Valley Authority (TVA). My business address is 1101 Market Street, PCC 2A, Chattanooga, Tennessee 37402-2801.

Q. What is your educational and work experience background?

A. I am a registered Professional Engineer in the State of Tennessee. I received a Bachelor of Science degree in Engineering (Electrical Power option) from the University of Tennessee at Chattanooga in 1982. I also received a Master degree in Business Administration from the University of Tennessee at Chattanooga in 2000.

I have over twenty-two years of work experience in the electric utility industry. I worked for fourteen years at Tampa Electric Company in Tampa, Florida, in various engineering and management positions in the areas of transmission planning, control area operations, generation planning, and power marketing. At the Tennessee Valley Authority I have worked in power marketing, control area operations, and reliability coordination. I currently have supervisory responsibility for the reliability coordination function.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to provide background regarding TVA, how TVA acts as a reliability coordinator for other electric systems (including other systems in Kentucky), and how TVA proposes to provide such services to Louisville Gas and Electric Company (LG&E) and Kentucky Utilities Company (KU) (collectively, the Companies).

Q. Please summarize your testimony.

A. As discussed herein, TVA has the requisite experience to provide reliability coordinator services to the Companies. Indeed, TVA provides similar services for entities in Kentucky today. Furthermore, based on the location of the Companies' loads, and certain operating conditions described herein, TVA is the logical entity to act as reliability coordinator for the Companies. The Companies' loads are dispersed within TVA's Kentucky reliability area already, and operations and planning will be facilitated if TVA acts as reliability coordinator for them.

Q. Please provide a brief description of TVA generally.

A. TVA is a corporate agency and instrumentality of the United States government created in 1933 by an act of Congress and charged with providing navigation, flood control, and agricultural and industrial development, while providing electric power to the Tennessee Valley region.

TVA is the largest public power company in the United States and operates one of the largest electric power systems in North America. TVA is completely self financing, and meets the needs of its power and non-power operations through internally generated cash flows. TVA raises capital for its power program primarily through public market financings. Other "quick facts" regarding TVA are as follows.

- Nation's largest public power system.
- $7.5 billion total revenues.
- 155 billion kWh total 2004 system generation.
- 166 billion kWh total 2004 power sales.
- 33,189 MW power system capacity (net winter dependable).
- 158 power distributors, 62 directly-served industries and government agencies.
- 99.999 percent transmission system reliability.
- 17,000 miles of transmission lines.
- 80,000 square-mile service area, covering parts of seven states.
- Steward of the nation's fifth-largest river system.
- 800 miles of commercially navigable waterways.
- 49 dams for integrated river management.
- $338 million in tax-equivalent payments to states and counties.

The TVA transmission system is one of the largest and most reliable in North America, having maintained 99.999 percent reliability over the past five years in delivering electricity to customers. TVA's system is comprised of almost 17,000 miles of transmission lines, about 117,000 transmission line structures, and 1,032 individual interchange and interconnection points, occupying over 258,000 right-of-way acres.

During the 2005 summer, TVA surpassed its all-time peak demand of 29,966 MW with demand of 31,703 MW on July 25 and demand of 31,935 MW the following day. These demands were met with no customer interruptions while also handling power from other areas moving across the TVA system. TVA demand exceeded 29,000 MW for eight consecutive days beginning July 20, 2005 with no customer interruptions.

TVA, as a NERC Reliability Coordinator, is responsible for monitoring and ensuring the reliable operation of the bulk transmission system in an 10-state region that includes Tennessee, and portions of Alabama, Georgia, Illinois, Iowa, Kentucky, Mississippi, Missouri, North Carolina, and Virginia.

Q. Does TVA currently provide reliability coordination service ?

A. Yes. TVA Reliability Coordinator (TVA RC) is one of five Reliability Coordinators in the Southeastern Electric Reliability Council (SERC). Created in 2001, the TVA RC office is located in Chattanooga, Tennessee.

TVA has entered into Reliability Coordination Agreements with Associated Electric Membership Cooperative (AECI), Big Rivers Electric Corp., East Kentucky Power Cooperative (EKPC), and Electric Energy, Inc. (collectively, the Members) and is the NERC-authorized Reliability Coordinator for each. The Members operate as Balancing Authorities and/or Transmission Operators with operations in the East Central Area Reliability (ECAR), Mid-America Interconnected Network, Inc. (MAIN), and SERC regions.

Each respective NERC region recognizes TVA as the Reliability Coordinator for the applicable Member and TVA RC complies with each applicable Region’s policies and standards. In addition to its own service territory, TVA currently provides Reliability Services to these four other Members under separate Reliability Services Agreements.

The TVA RC oversees an area of 192,000 square miles with a population of nearly 10 million people.

Q. Please describe how TVA is organized internally with respect to reliability coordination and transmission and generation scheduling and dispatch – *i.e.*, regarding the split and separation of functions.

A. TVA operates two geographically separated control centers, one for the Reliability Coordination functions and one for the Balancing Authority and Transmission Operator functions. The Regional Operations Center (ROC) is the main facility for the TVA's Reliability Coordinator and Transmission Provider and Interchange Authority functions. The System Operations Center (SOC) is the main facility for the TVA's Balancing Authority (including generation dispatch), and Transmission Operations functions. The SOC backs-up the ROC and the ROC backs-up the SOC.

Both facilities are in a hot standby mode at all times. Each site utilizes the same type systems and has back-up power supplies, and fully redundant communications independent of each other. The transfer to the back-up center would be transparent to the outside world as a phone script rolls the Reliability Coordinator's numbers from the ROC to the SOC. Once the Reliability Coordinator is in place at the SOC a notice would be posted on the RCIS informing everyone that TVA RC had relocated to the back-up facility.

NERC has established an Interregional Security Network (ISN) to facilitate the exchange of information needed by transmission system operators for transmission reliability purposes. TVA will assist the Companies in establishing the necessary telecommunications and other facilities required for the transfer of data in accordance with applicable NERC and Regional Reliability Organization policies and procedures. The TVA RC will coordinate all required data and information to and from the ISN.

The TVA RC will use information from the ISN solely to assist in the performance of its Reliability Coordinator responsibilities. The information supplied to and received from the Companies will be kept confidential in accordance and compliance with the NERC Data Confidentiality Agreement.

The structure and administration of the TVA RC includes a Reliability Coordination Advisory Committee (RCAC), which is composed of representatives from each entity that has executed a reliability coordination agreement designating TVA as its Reliability Coordinator. The RCAC assists the Reliability Coordinator in the development of new reliability coordination policies and operating procedures and the modification of existing reliability coordination policies and operating procedures. In connection with these activities, RCAC members have access to the necessary data and documents maintained by the Reliability Coordinator.

In addition, TVA has established Joint Reliability Coordination Agreements with neighboring Reliability Areas, RTOs and ISOs, which provide for the exchange of transmission-related data and information and establishes various arrangements and protocols for transmission planning and congestion management to enhance the reliability of their interconnected transmission systems and to facilitate efficient market operations. The Companies would have the option to participate as part of the TVA Reliability Area (TVA RA) in these agreements, procedures and protocols.

Q. How does TVA comply with standards of conduct ?

A. TVA is not a public utility under Section 201(e) of the Federal Power Act and, thus, is not directly subject to the requirements of Orders No. 888, 889, 2004, and other related FERC orders. TVA has elected, however, to comply voluntarily with these FERC orders and the associated regulations, to the extent they are consistent with TVA's responsibilities under the TVA Act and other applicable law. Accordingly, TVA has functionally separated its Marketing/Energy Affiliate from its Transmission Function and is conducting its operations in accordance with the attached Standards of Conduct.

The Standards of Conduct are intended to ensure that TVA does not use its unique access to non-public information about its own transmission system to unfairly favor its own Marketing/Energy Affiliate over others. The Standards of Conduct, along with the availability of TVA's Open Access Same-time Information System (OASIS), give potential customers access to information that will facilitate their obtaining transmission service on a non-discriminatory basis.

TVA Transmission Function Employees are located in offices in Chattanooga and in various other locations across the Tennessee Valley. Marketing/Energy Affiliate employees are located in separate offices in Chattanooga. The TVA SOC and ROC are staffed by Transmission Function Employees. Admittance to these facilities is controlled through card-key access. Marketing/Energy Affiliate employees are not permitted access to the SOC or the ROC in any way that differs from the access available to other Transmission Customers.

The Power Trading Floor, the center for TVA's Marketing functions, is also accessible only with a card key. Of Transmission Function Employees, only load coordination specialists and their management are permitted access to the Power Trading Floor. This access is necessary to coordinate the power supply to meet native load needs and to ensure system reliability.

Q. What is TVA's record regarding provision of reliability coordination services in and outside of the Tennessee Valley ?

A. TVA carries out it's duties as Reliability Coordinator in a manner consistent with NERC Standards, industry practices and business processes. TVA RC has been audited by NERC and SERC and received high marks for meeting Reliability Coordinator requirements. In its role as Reliability Coordinator, TVA has maintained regional reliability and consistently met all SERC and NERC compliance measures.

Recent accomplishments by TVA as BA, TO, and as Reliability Coordinator, are described below.

Reliability and Record Loads

TVA operates one of the largest and most reliable transmission systems in North America, having maintained 99.999 percent reliability over the past five years in delivering electricity to customers. TVA met an all-time record peak power demand on July 26, 2005, providing 100 percent of a 31,924 MW load at a temperature of 95 degrees. This included back-to-back days with loads in excess of 31,000 MW days, plus 17 of the top 20 highest peak demands in the history of TVA. TVA also managed successfully the impacts of a record-setting hurricane season – including, recently, Hurricane Katrina.

FY2005 Operating Performance

Record-level performances in NERC compliance (100%) and Interconnection Reliability Operating Limit (IROL) violations (0). Achieved the best Load Not Served performance in TVA history.

NERC Citations for Operating Excellence

TVA received two *Examples of Excellence* recognitions from NERC: Operator Training and Operating Procedure Change Management. TVA also transitioned the organization successfully to the NERC Functional Model framework, and implemented the new NERC Reliability Standards updating all our processes and procedures to align with revised and emerging industry rules.

Regional Partnerships

TVA successfully executed the Joint Reliability Coordination agreement with PJM and MISO. It initiated negotiations with SPP and SERC companies for new reliability agreements. TVA is an associate member of the RTO/ISO IT Council, and a charter member of the RTO Congestion Management Council, while deploying new congestion methodologies.

Enhancement of Operating Systems

TVA completed the implementation of the AREVA State Estimation tool for the TVA Reliability Area. It expanded Reliability Coordinator visibility through PowerWorld to include key flowgates and voltages for Reliability Area and neighboring utilities. It also implemented a new System Operator Log (eSoms) across operating desks, and successfully developed Enterprise 2.0 with GED that included key operational functionality, including ancillary services, ability to model derates, and other TVA-identified functionality.

Wide Area Visibility

TVA is the Eastern Interconnect real-time phasor data repository, and it set up the first Super Phasor Data Concentrator; connecting 23 PMU's from five different companies in the Eastern Interconnect.

Cyber Security

TVA implemented 7x24 security monitoring of the Reliability Control Network, which includes real-time monitoring, correlation and analysis of security events to known and unknown threats. It also issued the ESO Cyber Security Checklist to provide best security practices and link

Q. In acting as reliability coordinator, do you believe TVA will enhance reliability for the Companies' system?

A. Yes. The Companies' system is heavily interconnected with the TVA RA through inter-ties with BREC, EKPC and TVA itself. Incorporating the Companies into the reliability region would be a logical extension of the TVA RC given the interconnected nature of the Companies' system with the systems of the various members of the TVA RC. Coordinated studies with ECAR, MAIN, and the other SERC sub-regions indicate that adequate transmission transfer capability is available on all interfaces to support reliable operations.

Q. Are there any particular operating circumstances which may be improved by TVA acting as reliability coordinator for the Companies?

A. Yes. In real-time, TVA, as the Reliability Coordinator for the Companies, will allow direct coordination of operational issues among the operating systems as well as improved coordination and integration of planned maintenance activities for the BREC, EKPC, LG&E/KU, and TVA systems.

Q. How does TVA engage in planning today, and how does providing the service for the Companies dovetail with what TVA is doing now?

A. TVA currently models the Companies' system and facilities in its reliability models in order to ensure reliability for the TVA RA. Incorporating the Companies into the reliability region would be a logical extension of the TVA RA given the interconnected nature of the Companies' system with the systems of the various members of the TVA RA. Providing this service to the Companies will enhance reliability coordination for the TVA RC area by facilitating more frequent communications between EKPC, BREC, TVA, and the Companies, as well as improved coordination of outages.

As Planning Authority (TVA PA), TVA will ensure a long-term (one year and beyond) plan is available for adequate resources and transmission within the TVA RA. TVA will integrate and assess the plans from the Companies' transmission planners and resource planners to ensure those plans meet the reliability standards, and develop recommended solutions to plans that do not meet those standards. As Planning Authority, TVA will coordinate transmission system planning efforts with adjoining reliability areas and in accordance with neighboring Planning Authorities.

In particular, TVA PA will be responsible for:

- Developing transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy;

- Developing and applying methodologies and tools for the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans;
- The analysis of resource adequacy plans;
- Collecting information required for planning purposes;
- Evaluating, from a reliability standpoint, plans for customer requests for transmission service;
- Reviewing TTC values (one year and beyond) as appropriate; and
- Coordinating the integration of Planning Authority Area plans with neighboring Planning Authorities to provide a broad multi-regional transmission plan.

In performing these functions, TVA will:

- Maintain accurate computer models of the current and future Planning Authority Area and external interconnected power system for internal bulk system planning;
- Evaluate the Planning Authority bulk transmission system's ability to deliver its member's generation resources to native load and maintain a prioritized list of transmission capacity problems;
- Perform breaker duty studies of the bulk system to ensure that all bulk system breakers are operated within their interrupting capability;
- Provide data, as required, for NERC and Regional Compliance Programs and manage the steady state planning criteria and planning standards;
- Study alternative plans for identified bulk system problems for technical and economic merit and recommend the best solutions;

- Maintain a chronological plan for the ten-year planning horizon of the additional bulk system facilities required to deliver generation resources to the native load;
- Develop generation operational guides to maintain steady state transmission reliability;
- Perform system-wide and regional dynamic and transient stability studies, reactive analyses, exciter and Power System Stabilizer (PSS) setting studies;
- Support TOs with dynamic and transient stability studies, operational study checking, and assistance with operating guides;
- Perform non-PSS/E special studies including transformer specification, induced voltage, electromagnetic transients (EMT), unbalanced loadflow, flicker, Mathcad/Matlab, voltage collapse, undervoltage load shedding (UVLS), and optimal power flow (OPF) analyses;
- Compile and integrate system data with TVA system data, convert (if necessary) to compatible format, and transmit data to partners subject to Regional Coordination Agreements; and
- Ensure that TVA maintains confidentiality of all confidential system information provided to it.

Q. Please describe TVA's participation on the "RTO Council."

A. TVA is an associate member of the RTO/ISO IT Council, and a charter member of the RTO Congestion Management Council which is developing and deploying new congestion management methodologies.

Q. Please describe TVA's use of state estimator in its reliability operations.

A. TVA operates two completely separate Advanced Network Analysis (ANA) systems that perform state estimation and contingency analysis. Both systems are independently operated and have dual-redundant computer systems located in and immediately available at separate TVA control centers. Models used in both systems are built weekly using equivalent external area models derived from VAST operating cases maintained intra-monthly for configuration and facility changes within the region.

The ANA used by TVA Transmission Operations (TO) is a Siemens product, version TG8000, Rev 7.3. It covers the region served over the TVA transmission system and includes parts of the neighboring utility systems adjacent to TVA that are directly impacted by or have significant influence on flows inside the TVA transmission system. Portions of the Companies' system are included in this analysis. The model used in the TO ANA currently has 1400 substations with 2200 buses. It solves in real-time and runs 500 contingencies every 15 minutes. Only minor expansions of this model are planned over the next two years.

The ANA used by the TVA RC is an AREVA product, e-terra*platform* 2.2 with e-terra*habitat* 5.4.0. The model used in this system covers a much broader area and currently includes all of TVA, AECI, BREC, EKPC, EEI, most of LGEE, and parts of other utility systems adjacent to these areas that impact transmission system operations for these utilities. The model size currently has 3600 substations with 5100 buses. It solves in real-time and runs 840 contingencies every 5 minutes. Changes are planned to include real-time phasor measurements in this model, expand the observable areas further into the neighboring systems for better wide-area coverage, and activate routine use of the real-time transient and voltage stability analysis available in this system.

Q. Overall, do you believe that TVA is a "good fit" to act as the Companies' Reliability Coordinator ?

A. Yes I do. As noted above, TVA has the requisite experience and provides similar services for entities in Kentucky today. Furthermore, based on the location of the Companies' loads, and certain operating conditions, it makes logical sense for TVA to act as reliability coordinator for the Companies. The Companies' loads are dispersed within TVA's Kentucky reliability area already, and operations and planning will be facilitated if TVA acts as the Companies' reliability coordinator.

Q. Does this conclude your testimony?

A. Yes, it does.

VERIFICATION

STATE OF TENNESSEE)
COUNTY OF Hamilton) **SS:**
)

The undersigned, Stuart L. Goza, being duly sworn, deposes and says he is the reliability coordinator for the Tennessee Valley Authority, that he has personal knowledge of the matters set forth in the foregoing testimony, and that the answers contained therein are true and correct to the best of his information, knowledge and belief.

Stuart L. Goza
STUART L. GOZA

Subscribed and sworn to before me, a Notary Public in and before said County and State, this 6th day of October 2005.

Elizabeth H. McCoy
Notary Public

ELIZABETH H. McCOY NOTARY PUBLIC AT LARGE HAMILTON CO., TN

My Commission Expires:
11-10-05

Exhibit H

Paul W. Thompson
Senior Vice President
Energy Services

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502-627-3861
502-627-2995 FAX

VIA OVERNIGHT MAIL, FACSIMILE, AND ELECTRONIC MAIL
(317) 249-5945

December 28, 2004

Mr. James P. Torgerson
President & CEO
Midwest Independent System Operator, Inc.
701 City Center Drive
Carmel, Indiana 46032

Dear Jim:

Pursuant to and in accordance with Section 1 of Article Five and Section J of Article Nine of the Agreement of Transmission Facilities Owners to Organize the Midwest Independent Transmission System Operator, Inc. ("MISO"), a Delaware Non-Stock Corporation ("TO Agreement"), Louisville Gas and Electric Company and Kentucky Utilities Company (hereinafter, the "Companies"), each hereby tenders to you in your capacity as President of MISO notice of withdrawal to effectuate withdrawal of the Companies' facilities from the Transmission System (as defined under Article One of the TO Agreement). The Companies note that Section 1 of Article Five of the TO Agreement provides that, based on the delivery date of this notice of withdrawal, the Companies' withdrawal will not become effective at any time prior to December 31, 2005, and that such withdrawal requires the approval of the Federal Energy Regulatory Commission. Such withdrawal, when effective, shall terminate the Companies' status as an Owner pursuant to the TO Agreement.

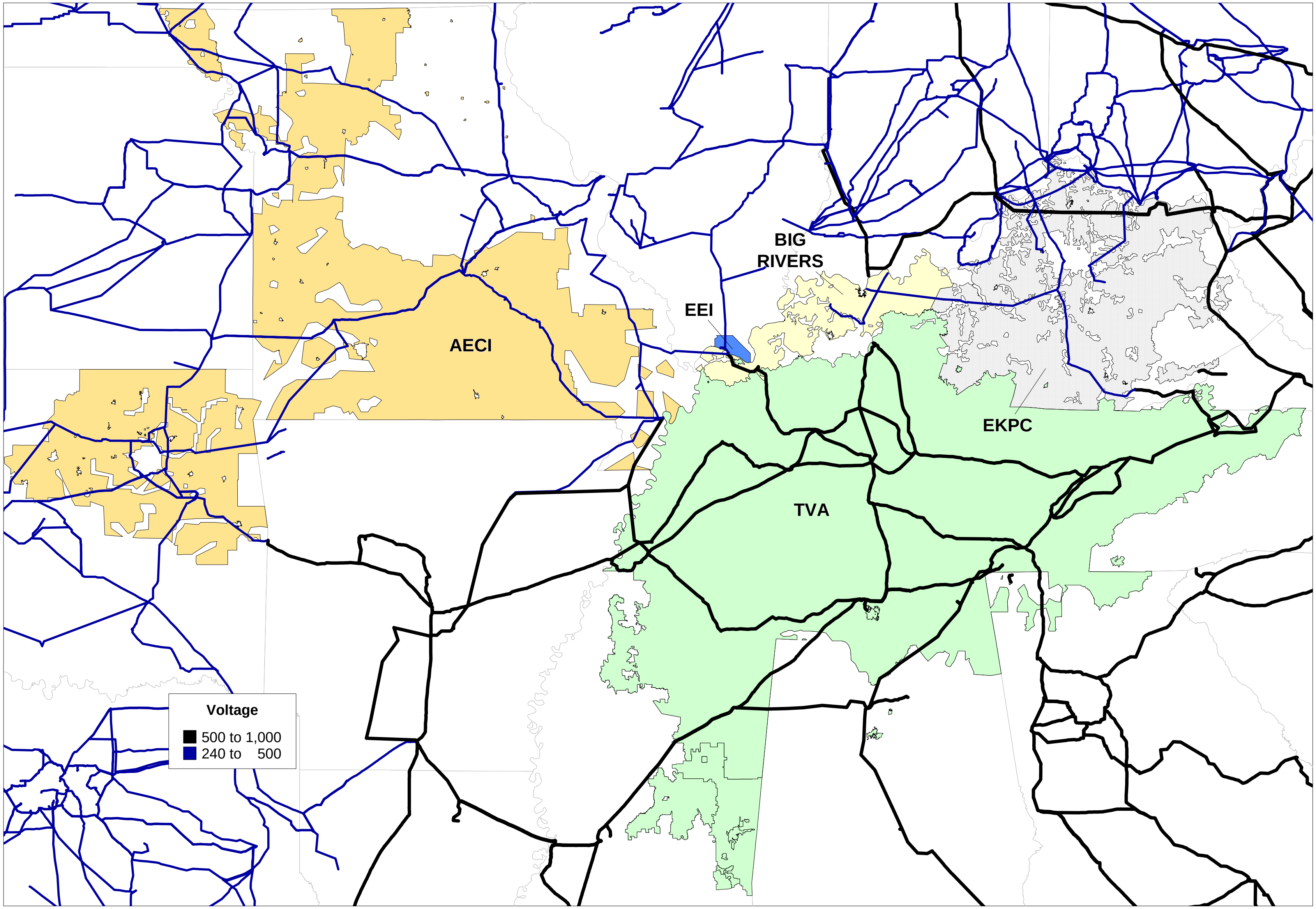
The Companies look forward to working with you closely to coordinate any transition issues that may arise. We are also certain that MISO and LG&E personnel will continue to coordinate their efforts to ensure that the system is operated in a reliable and efficient manner.

Please do not hesitate to contact me if you have any further questions.

Sincerely,

Exhibit I

Current TVA Reliability Area



Proposed TVA Reliability Area

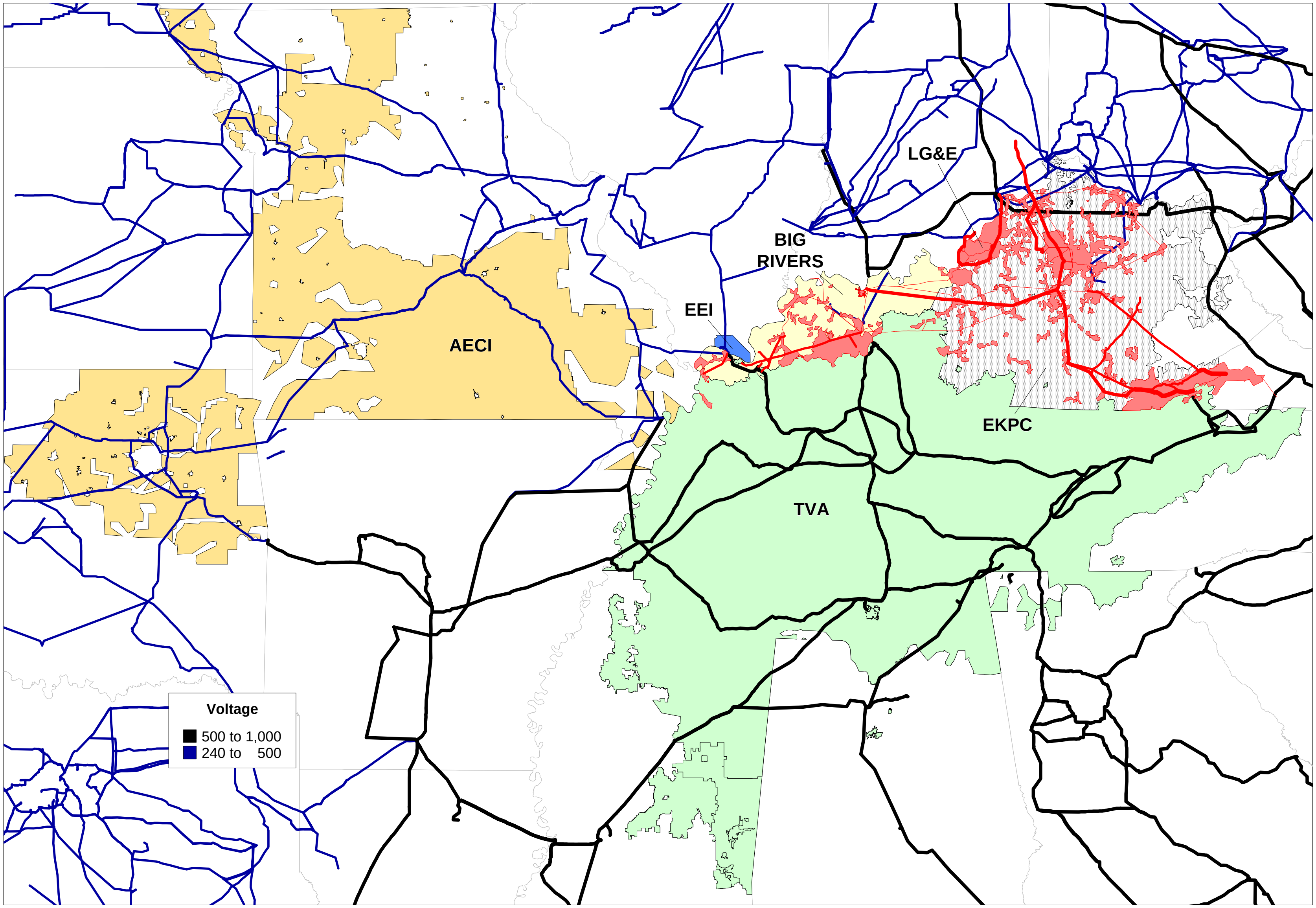


Exhibit J

Contract No. 00048801

Tennessee Valley Authority, 1101 Market Street, Chattanooga, Tennessee 37402-2801

Van M. Wardlaw, P.E.
Vice President
Electric System Operations

September 23, 2005

Mr. Mark S. Johnson
Director, Transmission
LG&E Energy, LLC
119 N. Third Street
Louisville, Kentucky 40202

Dear Mr. Johnson:

This Letter Agreement between the Tennessee Valley Authority ("TVA") and Louisville Gas and Electric Company and Kentucky Utilities Company ("LG&E/KU") will evidence our mutual intent to negotiate in good faith a Reliability Coordination Agreement ("RCA") under which TVA would act as LG&E/KU's designated Reliability Coordinator and provide other reliability-related services to ensure compliance with the applicable reliability coordination policies and procedures as defined by the North American Electric Reliability Council, any successor organization thereto, and the applicable regional reliability councils. This Letter Agreement also enables TVA to commence certain activities necessary to prepare TVA to provide Reliability Coordination ("RC") services to LG&E/KU.

Upon execution of this Letter Agreement, TVA shall begin preliminary work to enable TVA to incorporate LG&E/KU into the TVA Reliability Area. Such work shall include, but is not limited to, the preparation of engineering studies, the development of applicable computer systems and communication links, and other tasks associated with the provision of RC services. TVA shall formulate workplans, identifying specific tasks and timelines, and shall provide such workplans and associated estimated budgets to LG&E/KU for review and approval. Upon the receipt of written approvals from LG&E/KU, TVA shall perform the tasks set forth in approved workplans.

Upon approval of any workplan budget, LG&E/KU shall pay TVA the estimated budget amount for that workplan as a deposit for the work. The cost of the work to be performed by TVA hereunder shall be based on the time spent by qualified TVA personnel at their standard hourly rates (including applicable overheads), which shall not exceed $75 per hour, plus out-of-pocket costs for any materials consumed in performing such work. TVA shall not be obligated to incur and LG&E/KU shall not be obligated to pay costs in excess of the estimated budget amount per workplan, except by mutual agreement evidenced in the form of a written addendum to the applicable LG&E/KU approval. Following execution of the RCA, TVA shall apply any deposit

Mr. Mark S. Johnson
Page 2
September 23, 2005

amounts to the charges to be paid by LG&E/KU under the RCA. In the event that a mutually acceptable RCA is not executed by April 1, 2006, any remaining deposits held by TVA exceeding the cost of the work performed by TVA shall be promptly refunded to LG&E/KU.

TVA and LG&E/KU anticipate negotiating a mutually acceptable Reliability Coordination Agreement to be executed and implemented by April 1, 2006. This Letter Agreement is merely an expression of mutual intent with respect to the proposed RCA and does not constitute a binding agreement between the parties with respect to the proposed RCA. Neither TVA nor LG&E/KU shall bring any claim or action against the other as a result of failure to agree to execute a binding RCA.

If this is acceptable, please sign and date all copies of this Letter Agreement and return two (2) copies to me.

Sincerely,

Van M. Wardlaw, P.E.

Accepted and agreed to as of the 27 day of Sept., 2005.

Louisville Gas and Electric Company
Kentucky Utilities Company

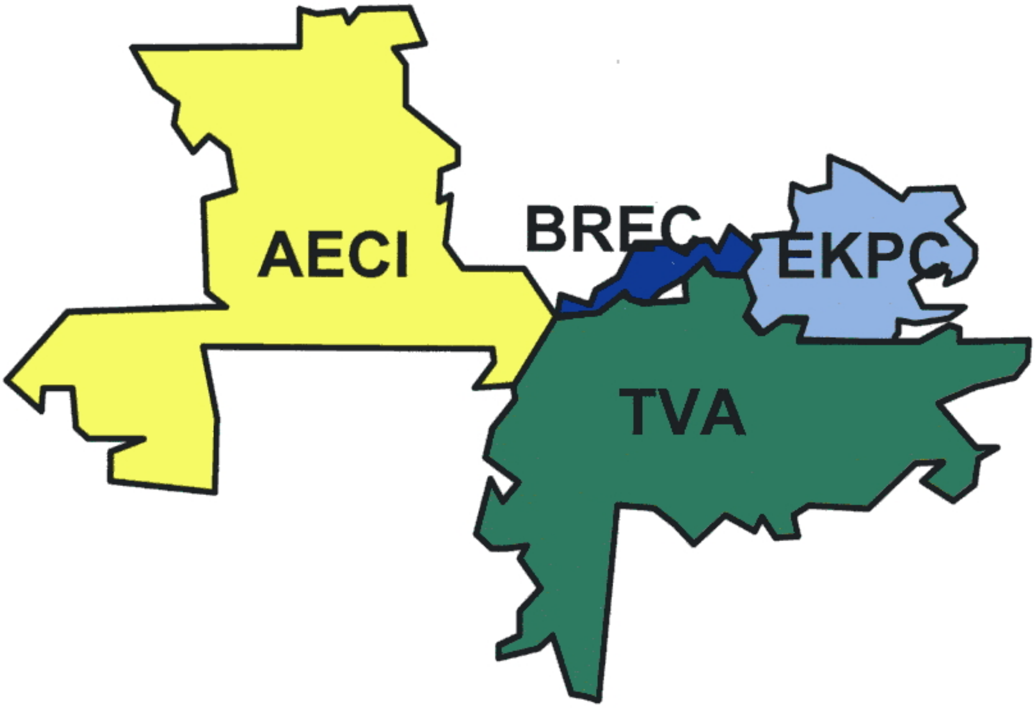
By: ______________________________
Mark S. Johnson
Director, Transmission

Exhibit K

TVA ESO Standard Processes and Procedures	TITLE TVA Sub-Region Reliability Plan	ESO-RA-SPP-10.200 Rev. 0000 Page 1 of 33 Effective Date 11-05-2002

Electric System Operations

Standard Process and Procedure



Prepared by:	Reliability Authority	
Approved by:	Bill Lundin, Manager, Reliability Authority	11/04/2002 Date
Approved by:	Van M. Wardlaw, Vice President, Electric System Operations	11/4/2002 Date
Approved by:	Mitchell E. Needham, Manager, Compliance and Standards	11/4/2002 Date

Current Revision Description

This document has been converted from Word 95 to Word 2002. Section 2.0, F - Changed "wholsale" to "wholesale"; "funtion" to "function"; and "simultaneoulsly" to "simultaneously." Section 6.3 - "nee" should be "need." Several sections have been added and/or rewritten to reflect the actual operational strategies. R0 reflects the initial issue in SPP format.

Table of Contents

1.0 PURPOSE

1.1 The TVA Reliability Sub-region

The TVA Reliability Sub-region (referred to as the Sub-region in the remainder of this document) consists of the utility entities (referred to as Members in the remainder of this document) listed in Appendix A. TVA performs the reliability functions for the Sub-region Members and is responsible for the safety and reliability of the bulk electric system under the Standards and Policies set by the North American Electric Reliability Council (NERC).

The TVA Regional Operations Center (ROC) is located in Chattanooga, TN. It is the designated NERC Reliability Coordinator for the Members. The ROC has been given the authority by the members to perform the duties and responsibilities of the NERC Reliability Coordinator through the Reliability Coordination Agreements. TVA provides the services and personnel and maintains the facilities of the ROC. The ROC staff includes Engineers, System Operators, technicians, computer programmers and other professionals.

1.2 TVA Regional Operations Center (ROC)

1.2.1 Mission Statement

The mission of the ROC is to provide for the reliable operation of the Sub-region. This is achieved through pro-active, coordinated regional and interregional oversight of the system in accordance with all SERC, ECAR, and NERC requirements.

1.2.2 Responsibilities

The ROC is responsible for overseeing the operation of the Sub-region's bulk electric system. This includes monitoring the status of the system to verify that operating limits and guides are maintained and to ensure the system is operated in a reliable state. The ROC also works with the Member systems to implement emergency actions to maintain reliability. The emergency actions and procedures are as outlined in Section 9 of this document.

The ROC has important roles in several aspects of Sub-region system operation. These roles, along with the roles of the Sub-region Membership and Sub-region committees, are provided below. The critical roles can be categorized as:

- Providing pro-active analysis of Sub-region reliability.
- Responding to real time reliability issues.
- Providing after-the-fact analysis and reporting.
- Providing NERC and Regional Standards compliance.

These roles must be undertaken in the context of the ROC operating as a NERC Reliability Coordinator.

1.3 Pro-active Analysis of Regional Reliability

1.3.1 ROC Role

The ROC provides analysis of next day, next week, next month, next season, and next year operations. Its major concerns are generation operating reserves and transmission system reliability.

These analyses identify potential problems. To resolve and/or mitigate these identified potential problems, the ROC must contact those entities (Sub-region Members and other regions) that can affect the potential problems, inform them of the problems ROC sees, and direct them to take all necessary steps to operate in a reliable state.

The individual control area reserves are monitored. The ROC assists the Control Areas in arranging for assistance from neighboring areas (control areas, regions, etc.) and issues operating reserve deficiency alerts as appropriate

In the transmission area, there are several functions:

- The ROC will assemble and coordinate critical equipment outage schedules. If necessary, this may include checking that each outage is addressed in an appropriate operating guide. Through the Sub-region Operating Committee (OC) requirement for appropriate operating guides and through involvement in mediation when conflicting outages negatively impact system reliability, outages will be coordinated and reliability maintained.

- The ROC will perform reliability analysis to ensure that the system will be reliable from current hour through the next 13 months. This analysis will use real-time data, the outage schedules, load forecasts, generation unit availabilities, interchange schedules, and any forced outages supplied by the Members.

- The ROC may maintain current postings on OASIS for some Members. Other Members will maintain their own OASIS postings.

- In evaluation of future operation, the ROC will evaluate Regional and Interregional reliability concerns and will communicate them to the Membership. If reliability studies indicate a problem, the ROC will initiate correction of the problem through the applicable Sub-region procedures.

- The ROC will coordinate planning for and execution of system restoration.

1.3.2 Members Role

In order for the ROC to fulfill the role defined above, it is essential for all Sub-region Members to supply the relevant data to the ROC as required.

When the ROC establishes that a reliability risk exists and directs the Member to take steps to alleviate the risk, that Member must act responsibly and quickly.

1.3.2 Members Role (continued)

It is recognized that the ROC has the responsibility to identify potential problems and to contact whichever Members it believes are in a position to alleviate the problems. The Members, through the requirements set forth in the Reliability Coordination Agreement, have an obligation to act to maintain reliability in the Sub-region. Members must comply with directives from the ROC since they are being supplied from Regional and Interregional perspectives. Similarly, since the ROC may not be aware of or be able to identify local problems, Sub-region Members must provide information on local problems that might impact regional operation, to the ROC.

1.4 Responding to Current Reliability Issues

1.4.1 ROC Role

The ROC will assemble a comprehensive picture of Sub-region operation, capturing load, generation, flowgate flows, and topology information and estimating a first contingency picture of the Sub-region in real-time. The ROC will monitor system conditions and will flag overloads, potential violations of Operating Security Limits (OSL) and voltages. If an OSL is being violated, the ROC will inform the Member system(s) and require correction of the problem.

The ROC will be communicating in real time with other regions/RTOs when necessary.

Other real time functions include:

A. Administer TLR or other curtailment procedures.

B. Ensure that all NERC tags are made available to the NERC Interchange Distribution Calculator (IDC), and that all Members' transactions are Tagged.

C. Update database for SDX and RCIS.

D. Administer operating guides for Members, as delegated.

E. Coordinate emergency procedures

F. Coordinate restoration procedures

1.4.2 Members' Role

As noted above, it is vital that the Members provide correct, current data to the ROC.

Control Areas will maintain their own reserves on a continuous basis, provide accurate information to the ROC, and notify the ROC of any deficiencies.

1.5 Providing "After the Fact" Analysis and Reporting

1.5.1 ROC Role

Based on protocols approved by the Sub-region OC or its subcommittees, the ROC will perform several compliance data gathering and processing functions. These include:

1.5.1 ROC Role (continued)

- TLR reports and audits and analysis for same.
- EEA reports and analysis for same.
- Audit logs.
- Standards of Conduct reporting.

1.5.2 Member Role

Member Control Areas will continue to provide Control Area reporting functions.

1.6 Other Roles

The ROC will be involved in interregional affairs including NERC business. It will generate reports for a wide range of groups and regulatory bodies on behalf of the Members.

2.0 RELIABILITY COORDINATOR OPERATING CRITERIA

NOTE

In the following, the **BOLDED, CAPITALIZED** sentences reflect NERC Policy requirements.

A. MUST HAVE CLEAR SET OF RESPONSIBILITIES FOR WHEN, WHERE, AND HOW TO TAKE ACTION

The responsibility of the ROC is to oversee the operation of the bulk transmission system in the Sub-region. The ROC System Operators monitor the status of the power system to verify the system is within the operating limits and guides. Emergency actions and responsibilities are defined in Section 9 of this document. Through coordination with the transmission provider, the ROC may curtail schedules to eliminate an Operating Reliability Limit by using the NERC TLR procedure. Details of the responsibilities are defined in the Operating Agreements (Appendix C), the Reliability Coordination Agreements (Appendix C), and the Operating Procedures documents (Appendix D).

B. MUST HAVE KNOWLEDGE OF CURRENT AND PLANNED CRITICAL FACILITY STATUS

Knowledge regarding the status of the Sub-region power system is made available via real-time and near real-time data sent to the ROC by the Sub-region Members. Forced transmission and generation outages are reported to the ROC by the Sub-region Members via e-mail, the ppRTG web-site, and ISN data. Knowledge of the TVA system is through direct SCADA.

2.0 RELIABILITY COORDINATOR OPERATING CRITERIA (continued)

C. MUST HAVE AUTHORITY TO ACT AND TO DIRECT ACTIONS TO BE TAKEN BY OTHER OPERATING AUTHORITIES WITHIN THE RELIABILITY AREA

The NERC and Sub-region operating policies and procedures provide the foundation for which the ROC operates. It is recognized that the TVA Reliability Coordinator has the responsibility to identify potential problems and to contact whichever Members it believes are in a position to alleviate the problems. The Members, as stated in the Reliability Coordination Agreements, are required to take action as directed by the TVA Reliability Coordinator to maintain reliability in the Sub-region. Members must comply with directives from the ROC since they are being supplied from Regional and Interregional perspectives. Similarly, since the ROC may not be aware of or be able to identify local problems, Sub-region Members must provide information on local problems that might impact regional operation, to the ROC.

D. MUST ACT IN THE INTEREST OF THE RELIABILITY OF THE OVERALL REGION / INTERCONNECTION BEFORE ANY OTHER ENTITY – CONTROL AREA, PURCHASING SELLING ENTITY, ETC.

1. The primary responsibility of the ROC is to maintain reliability of the bulk electric system. This includes analyzing and performing studies on the power system to detect possible loading or stability problems, and working with Member systems to eliminate these problems when they occur. This is achieved by analyzing and evaluating near real-time flow data sent by the Member systems and external systems and developing power flow models that represent the current configuration of the power grid. These studies help determine the status of the power system as a whole and the Member system individually.

2. The ROC represents the Sub-region as the Reliability Coordinator and performs these functions. The ROC and the employees within the ROC, have functional and physical separation from the affiliated marketers of the entities for which the ROC provides reliability services. All generation/marketing information is kept confidential and is used by the ROC solely for power system evaluation purposes.

E. MUST HAVE ADEQUATE STAFF AND FACILITIES

1. ***ROC OPERATIONS***

   The ROC operates on a continuous basis, 365 days a year. The ROC operation department includes Electrical Engineers trained in load-flow analysis, and a staff of System Operators that maintain 7x24 system monitoring coverage. Engineering Managers and System Operators are NERC certified. Each position has its own job description including the requirements and expectations of that position as well as training requirements and qualifications that must be met before one is considered for promotion.

2. ***TRAINING***

2.0 RELIABILITY COORDINATOR OPERATING CRITERIA (continued)

In addition to the standard training program which is available to all TVA employees, the ROC employees may also receive specialized training from two different trainers and from ROC Reliability Engineering as well. The ROC has developed an extensive training program which all ROC operating personnel must pass. This specialized training is aimed toward helping the employee attain TVA specific skills and knowledge and maintain NERC certification. Once NERC certification has been achieved, the employee then maintains his/her skills and NERC certification via continuing education.

- Some of the specific training subjects include:
- The Basics of Power System Operations - TVA specific skills and knowledge
- EPRI Power Systems Operations
- NERC Policies
- Preparation for NERC Certification
- Power System Emergency and Restoration
- Operating Procedures and Guides
- Reliability Coordinator’s Tools and Information Systems (e.g. RCIS, IDC, ISN, EEA, TLR, etc.)
- Miscellaneous Computer Skills (e.g. Windows, Excell, Word, etc.)

In addition extensive job related electric industry experience is required. This may include Hydro, Fossil, or Nuclear generation experience; or, experience in either bulk transmission or Control Area operations.

In the near future, a simulator will also be available for training. It will have identical consoles, displays and software tools which are used within the ROC.

3. ***FACILITY/RELIABILITY***

The ROC facility is a state-of-the-art facility that includes a wide array of equipment used by the ROC Operators. The entry and exit gates are controlled by computer and operate via the use of a personal employee access card. All doors of the ROC building itself require card access. Only Sub-region personnel who have specific authority or reason to enter the ROC have the ability to do so. The entire grounds, internal and external, are monitored with cameras.

2.0 RELIABILITY COORDINATOR OPERATING CRITERIA (continued)

4. ***COMMUNICATIONS***

The primary data communication systems in the Sub-region are phone, e-mail and the ppRTG web-site. The ppRTG web page provides an avenue by which documents, information and other data related to TVA and the Members can be shared. This program provides password access only protection for the documents and information which might be considered sensitive by TVA and the Members. The ROC also has dedicated voice and video conferencing capability.

5. ***TOOLS***

The ROC receives SCADA at a four second update rate and ISN data that updates at least once every thirty seconds. These data points are sent from the Sub-region Members via ICCP over the ISN (see Section 4.0) and are input to a Tele-Gyr Network Application System.

F. MUST BE PHYSICALLY AND FUNCTIONALLY SEPARATE FROM ANY WHOLESALE MERCHANT. MUST NOT PASS ON INFORMATION OR DATA TO ANY WHOLESALE MERCHANT FUNCTION THAT IS NOT MADE AVAILABLE SIMULTANEOUSLY TO ALL SUCH WHOLESALE MERCHANT FUNCTIONS

The ROC and the employees within the ROC are physically and functionally separate from any affiliated marketing entity of any Member. All generation/marketing information is kept confidential and is used by the ROC solely for power system evaluation purposes. TVA has signed the NERC Data Confidentiality Agreement and all ROC personnel have completed the TVA Standards of Conduct training. In addition all ROC personnel are subject to the NERC Reliability Coordinator Standards of Conduct. In like fashion, the Members also maintain Standards of Conduct.

3.0 RELIABILITY COORDINATOR FUNCTIONS

A. MONITORING PARAMETERS THAT MAY HAVE SIGNIFICANT IMPACTS

The ROC receives real-time and near real-time system data from the Sub-region Membership. These data points are input to the Tele-Gyr SCADA system. From this point, they feed into a wide array of computer applications. Critical facilities outside and bordering the Sub-region are also monitored.

B. MONITORING/DETECTING PARALLEL AND LOAD SERVING FLOWS

The ROC uses a number of tools to evaluate the status of the power system as well as determining or predicting the status in the near future. The Sub-region Flow Gate Monitor is used by the ROC System Operators to look ahead at the impact of the worst first contingency. The NERC Interchange Distribution Calculator (IDC) and Flow Impact Study Tool (FIST) are used by the ROC System Operators to look ahead at the impact of interregional schedules to determine the loading effect on Sub-region constraints.

3.0 RELIABILITY COORDINATOR FUNCTIONS (continued)

C. CONFIDENTIALITY

Confidentiality of all operations data that is market sensitive is maintained. TVA is a signatory to the NERC Confidentiality Agreement, and all ROC staff members are trained in the requirements of the TVA Standards of Conduct. The procedures the ROC follows when distributing TLR reports have been developed through NERC committees.

D. AVAILABILITY/SHORTAGE OF OPERATING RESERVES TO MAINTAIN RELIABILITY

The responsibility of maintaining adequate reserves lies upon the control areas within Sub-region. The ROC monitors the reserves of the Members and assists the Members in obtaining additional capacity when reserves are deficient. These actions may include declaration of Energy Emergency Alert (EEA) levels for the energy deficient Member.

E. ACTUAL FLOWS VERSUS LIMITS AT KEY FACILITIES

Knowledge regarding the status of the Sub-region power system is made available via real-time and near real-time data sent to the ROC by the Sub-region Members. Forced transmission and generation outages are reported to the ROC by the Sub-region Members. The ROC Operators monitor critical facilities and transmission elements per the defined operating guides and limits.

F. TIME ERROR CORRECTION NOTIFICATION

The ROC is the time monitor for the Sub-region. Operating procedures and computer applications are in place to perform these functions.

G. SOLAR MAGNETIC DISTURBANCES

The ROC is responsible for notifying the Member Control Areas of SMD forecasts and will assist the CAs in their response plans.

H. RELIABILITY ISSUES OF OTHER REGIONS

The Sub-region Reliability Coordinator participates in NERC, SERC, and ECAR Hotline calls and communicates with other Reliability Coordinators to address Regional problems.

I. SYSTEM FREQUENCY AND RESOLUTION OF SIGNIFICANT FREQUENCY ERRORS, DEVIATIONS, AND REAL-TIME TRENDS

The ROC Operator monitors system frequency on a continuous basis. The ROC Operator will share this information on the NERC Hotline and RCIS when appropriate. In addition, the ROC monitors system frequency in five locations (two at Sub-region and one at each of the other Members) throughout the Sub-region in order to identify system separation.

3.0 RELIABILITY COORDINATOR FUNCTIONS (continued)

J. SHARING WITH OTHER RELIABILITY COORDINATORS ANY INFORMATION REGARDING POTENTIAL, EXPECTED, OR ACTUAL OPERATING CONDITIONS THAT COULD IMPACT OTHER RELIABILITY AREAS

The ROC shares power system information via the ISN per section four of the Sub-regional Reliability Plan. All Sub-region generation and transmission information is transferred to NERC via System Data eXchange (SDX) data. The ROC System Operator relays critical operating information to the Sub-region Membership and to the NERC Reliability Coordinators via the Reliability Coordinator Information System (RCIS). In addition, the ROC System Operators use NERC IDC and FIST to look ahead in order to detect upcoming loading problems.

K. AVAILABILITY/SHORTAGE OF INTERCONNECTED OPERATIONS SERVICES REQUIRED

The Sub-region Reliability Coordinator will and does assist the Sub-region Control Areas in arranging assistance from neighboring areas. The ROC System Operator uses the NERC hotline and RCIS to inform other Reliability Coordinators regarding an emergency condition and the need for assistance.

L. INDIVIDUAL CONTROL AREA OR RELIABILITY AREA ACE

The ROC will monitor the individual Control Area ACE and the Sub-regional ACE. Sub-region control area and regional performance for “disturbance criteria standards” surveys are performed per the policies and procedures described in Section 6.

M. USE OF SPECIAL PROTECTION SYSTEMS

No special protection systems are used within the TVA Reliability Area.

N. CONTROL AND RESTORATION OF ISLANDED AREAS

The ROC receives multiple frequency readings from specific areas in the Sub-region that would be utilized during separation. Details of Emergency and Restoration Plans and Procedures are contained in Appendix E.

O. ENSURE THAT THE RELIABILITY COORDINATOR STAFF ADHERE TO THE DATA CONFIDENTIALITY AGREEMENT

Every ROC employee is subject to the NERC Data Confidentiality Agreement and is trained in the TVA Standards of Conduct. NERC Certification training and on the job training ensure that the employee is awae of the requirements for data confidentiality.

Procedures have been established to address reported violations of the confidentiality agreement.

3.0 RELIABILITY COORDINATOR FUNCTIONS (continued)

P. ASSUME THE RESPONSIBILITY FOR THE SAFE & RELIABLE OPERATION OF THE BULK INTERCONNECTED TRANSMISSION SYSTEM IN ACCORDANCE WITH NERC, REGIONAL, AND SUB-REGIONAL PRACTICES

The ROC Operators monitor and operate the bulk electric power system to ensure the system is maintained within defined operating limits and guides. As defined in the Sub-region Reliability Plan, the Operators and the Members implement or direct emergency actions as required. This working relationship is defined in Section 9 of this document while specific plans and procedures are included in Appendix E. The NERC and Sub-region operating policies and procedures provide the foundation upon which the ROC operates.

Q. DETERMINE THE DATA REQUIREMENTS TO SUPPORT THE RELIABILITY COORDINATOR FUNCTION AND COORDINATE FOR THE PROVISION OF SUCH DATA

The OC will determine the data requirements for Reliability Coordination of the Sub-region. Other improvements needed for the ROC, as determined by the OC, may involve changes mandated by NERC policy or by the Sub-region Membership.

R. PROVIDE, OR ARRANGE PROVISIONS FOR, DATA EXCHANGE TO OTHER RELIABILITY COORDINATORS VIA THE INTERREGIONAL SECURITY NETWORK

The ROC shares power system information via the ISN per Section 4.0 of this Sub-region Reliability Plan.

S. CONDUCT RELIABILITY ASSESSMENT AND MONITORING PROGRAMS TO ASSESS CONTINGENCY SITUATIONS

The ROC performs reliability analysis to help determine possible problems or situations on the power system by using a PTI steady state power flow model. The model contains the predicted configuration and loading for the peak hour of the Sub-region. Real-time first contingency analysis is performed by distribution factors applied to the real-time telemetry and near real-time ISN data on flow-gate flows. The list of flow-gates that are used for this analysis is continually updated as changes to system topology, generation, and load occur. Plans call for the implementation of a real-time reliability analysis using the Tele-Gyr advanced applications package.

T. THE RELIABILITY COORDINATOR WILL ENSURE EACH CONTROL AREA HAS A RESTORATION PLAN

The RC and Members will ensure that each Control Area has a Restoration Plan. These plans will be revisited and revised periodically as changes to the system may dictate. The Restoration Plan will be implemented when required as delineated in Section 9 of this document. Specific plans are included in Appendix E.

3.0 RELIABILITY COORDINATOR FUNCTIONS (continued)

U. RUN VOLTAGE COLLAPSE STUDIES

Voltage Collapse evaluations and studies are performed by the Sub-region Control Areas. The Sub-region Standing Operating Guides include voltage collapse evaluation data.

V. PROVIDE OTHER COORDINATION SERVICES

All important and critical information is communicated from the ROC to the NERC Reliability Coordinators via the RCIS. All important and critical information attained via NERC Reliability Coordinators is communicated to all Sub-region Members via e-mail, the public power Regional Transmission Grid (ppRTG) web page or telephone.

4.0 OPERATIONS RELIABILITY INFORMATION, INTERREGIONAL SECURITY NETWORK (ISN)

Availability of Operational Reliability Information

Each Operating Entity in the Sub-region that does not communicate with the ROC via SCADA is required to provide Transmission System data to the ROC at a 5-minute or faster update rate through the NERC Interregional Security Network (ISN). The ROC maintains SCADA and ICCP systems that collect the data and distribute it to various applications. These systems also are used to exchange data with other Reliability Coordinators via the ISN. Sub-region data exchanged over the ISN is updated at a 30 second interval, regardless of the timing of the incoming data. These systems are also capable of exchanging data received via the ISN to Sub-region Operating Entities companies who sign the NERC data confidentiality agreement.

The following is a summary of each Operating Entity's near term plans for supplying near real-time power system data:

Control Area	Data Source
TVA	Transmits data via ICCP and SCADA
AECI	Transmits data via ICCP
BREC	Transmits data via ICCP
EKPC	Transmits data via ICCP

IPP	Control Area	Data Source
Red Hills	TVA	SCADA
Batesville Generation	BCA/TVA	SCADA
Brownsville Power	TVA	SCADA
Caledonia Power I	TVA	SCADA
New Albany Power I	DEAM	SCADA
Gleason Power	AEGL	SCADA
Duke Energy Marshall	DEMK	SCADA
Duke Energy "Looper's Farm"	DEMT/SOCO	ICCP

4.0 OPERATIONS RELIABILITY INFORMATION, INTERREGIONAL SECURITY NETWORK (ISN) (continued)

Decatur Energy Center	TVA	SCADA
Bolivar	TVA	SCADA

5.0 EVALUATING SYSTEM CONDITIONS / PERFORMING RELIABILITY ANALYSIS / SHARING INFORMATION

5.1 Building Sub-region Analysis Models

5.1.1 General

This document is intended to reflect the policies and procedures used by the ROC to perform reliability analysis and to ensure the bulk power system can be operated in anticipated normal and contingency conditions. These policies and procedures reflect the implementation of the ROC mission statement, and relevant actions by Sub-region Committees. If a situation occurs that is in conflict with the policies described in this document, the Reliability Engineers will revert back to an existing operating guide and/or provide conflict resolution between parties if the conflict occurs in the operation timeframe otherwise it will go before the appropriate Sub-region committee(s).

This document will be updated periodically based on decisions by the Sub-region Committees as to what functions the ROC is to perform. The ROC also may update this document on how those functions are implemented.

The policies and procedures address the following topics:

A. Role of the ROC Reliability Engineers

B. Role of the ROC System Operators

C. Role of the Members

There is a separate section in this document for each of the above three items. This document also contains appendices with specific information related to ROC Support. Cross-references to other sections and appendices of the document are included where appropriate.

5.1.2 Introduction

The ROC provides a current hour and next day through next 13 month operations. The look-ahead must flag potential problems. To resolve and/or mitigate potential problems, the ROC will assemble and coordinate critical equipment outage schedules while checking that each outage has an appropriate operating guide if necessary. The ROC Reliability Engineers and ROC Operators will perform contingency analyses when warranted, to ensure the system will be reliable for current and future operations. This function will use the real-time data, outage schedules, load forecasts and generation commitments and outages supplied by the Members. The ROC Reliability Engineers will keep abreast of regional reliability and planning studies completed for the next month, next season, next year, and out year timeframes.

5.2 Role of the ROC Reliability Engineers

The goal will be to have the Reliability Engineers trained to use the PTI software including Maximize Utilization of System Transmission (MUST), TLTG for Transmission Transfer Capability, and Power System Simulator Engineering (PSSE). They will also be trained in using the Real-Time First Contingency Analysis tool (RTFCA). This tool is based on distribution factors, calculated off-line and/or by NERC IDC, which are applied to real-time and near real-time flows on flowgates supplied by SCADA and ISN. In the future the Reliability Engineers will also implement on-line Transfer Capability Evaluation (TRACE) and the Advanced Applications State Estimator (SE) and Real Time Contingency Analysis (RTCA) on the Tele-Gyr system. The target date for Advanced Real-Time Applications is January 2004. The Reliability Engineers shall have a common approach for setting up base cases and a common understanding of which contingency simulations need to be run on an as needed basis. The Reliability Engineers shall understand the issues facing the operator and locate the necessary information (outage schedules, contingencies to simulate) to run reliability simulations. The Reliability Engineers shall interpret the results and disseminate the results to the operators.

To be compliant with NERC policies, the Sub-region has developed a web page for the Reliability Coordinators. The ROC Reliability Engineers and System Operators will post the conditions for current day, next day, and out through 13 months.

The ROC RELIABILITY ENGINEERS:

- Will perform or obtain assistance from the Planning Section to perform stability studies involving current conditions or in emergency situations as needed.
- Will support the OC as questions arise regarding model solution or Member-created operating guides.
- Will look at all outages with emphasis on the current and next-day.
- Can support Member companies and/or Sub-region committees in instances where an issue or question has arisen and/or when a constrained interface is affected.
- Can support Member companies and/or Sub-region Committees, as time permits, to perform comparison studies in non-emergency situations. While this is not required, it may be an area where the ROC can provide additional service to the Members.

A. STABILITY STUDIES

As a transmission outage occurs, the ROC Reliability Engineers will work with the Transmission Operators to manage any real-time loading problems and will provide required studies. For stability issues, existing operating guides will be utilized until the TP Planning departments perform studies to produce solutions.

B. THERMAL STUDIES

The ROC performs thermal studies on the Sub-region contingencies. Currently, the ROC creates power flow models of the peak hour for the current day through 13 months and performs contingency analyses on these models. Real time thermal contingencies are being performed using the Tele-Gyr flowgate monitoring displays.

5.2 Role of the ROC Reliability Engineers (continued)

C. NEAR REAL TIME STUDY ANALYSIS

Distribution factors combined with real-time SCADA and near real-time ISN data are used to monitor first contingency Operating Security Limits (OSL). In the future the Reliability Engineers will also implement TRACE and the Advanced Applications (SE and RTCA) on the Tele-Gyr system. The plan is for the System Operators to have the real-time tools to perform real-time Contingency Analyses.

D. UPDATING CURRENT DAY CONTINGENCY ANALYSIS

Each morning the ROC Reliability Engineers will participate in a conference with the Sub-region Members to discuss the current day conditions and the health of the power system. This includes any changes on the system that have taken place during the previous hours. The ROC Reliability Engineers will then update the current day model for current and next day conditions, perform contingency analysis and post this critical information. If there are significant impacts to the sub-region transmission grid, that information will be communicated to the Transmission Providers.

E. CREATING NEXT DAY CONTINGENCY ANALYSIS

In the afternoon, the ROC Reliability Engineers will obtain all information identified in the study criteria section and create the model for the next day. The contingency analysis will be run for evaluation of the next day.

F. STUDY CRITERIA SECTION

The ROC Reliability Engineers will perform this task according to the process defined in the "TTC/ATC Calculation Process." The on-call Reliability Engineer will make necessary changes to the model and re-run the studies if necessary.

5.2.2 Role of the System Operators

The System Operator will notify the on-call Reliability Engineer of any major unscheduled outages on the bulk transmission system. The on-call Reliability Engineer will make necessary changes to the model and re-run the next-day studies, if necessary.

Until real-time Stability analysis tools become available, the ROC cannot perform stability studies that meet the 30-minute criteria. Therefore, stability criteria will be conservatively followed to maintain grid reliability.

RELIABILITY COORDINATOR ppRTG WEB PAGE

The Sub-region Reliability Coordinator web page includes the current Sub-region system conditions, TLR information, and Sub-region contingency analysis information for current day through 13 months. This web page is password protected.

5.2.3 Role of the Member

Members shall supply the TVA reliability Coordinator with all data required by the RC for reliability studies and analyses of the power system. The results will be shared among the parties. Member companies also shall abide by the decisions of the Operating Committee. Members shall participate as required in conference calls with the RC to coordinate maintenance schedules and other reliability issues.

MEMBER SYSTEM DATA USED TO PERFORM RELIABILITY ANALYSIS

1. Generator availability
2. Generation and Transmission Outage Schedules (Current to 13 Month) in NERC SDX data format.
3. Load forecast, operating reserves, net interchange (Current to 13 Month) in NERC SDX data format.
4. Transmission Maintenance schedules (10 day short term outlook)
5. Load forecast (10 day short term outlook)
6. Daily conferences to capture changes to Member's operation plans.
7. Scheduled Tags.

DATA FROM BORDERING REGIONS WILL ALSO BE USED

1. Major generation outages (>100 MW)
2. Major transmission outages
3. Data changes via Conference Calls.

OTHER VITAL INFORMATION USED

1. IPP future plans
2. Firm transmission requests
3. NERC System Data Exchange
4. NERC Reliability Coordinator Information System
5. EPRI Tag Net Program

6.0 IMPACTS OF PARALLEL FLOWS AND UNCOORDINATED RESERVATION AND SCHEDULING ON TRANSMISSION RELIABILITY

6.1 Introduction

The ROC will participate on NERC working groups and task forces to promote Inter-connection wide evaluation and mitigation of adverse impacts of loop flows.

6.2 Flow-Based Tools and Procedures Developed in the Sub-region

6.2 Flow-Based Tools and Procedures Developed in the Sub-region (continued)

FIST - Flow Impact Study Tool

TVA participated as a core development task force member on the NERC Flowbased Task Force. This task force developed and implemented the FIST (Flow Impact Study Tool) for the whole Eastern Interconnection. TVA has acquired the FIST software license and can access FIST via the NERC Interchange Distribution Calculator (IDC). The FIST tool and related information are helping TVA to monitor all flowgates on the Eastern Interconnection. Thus, to ensure that current NERC Policy requirements are achieved and that an over-subscription of the network (resulting in repeated TLR incidences) does not routinely occur.

On - Line TRACE - Simultaneous Transfer Evaluation Tool

Unprecedented thermal/voltage problems have caused numerous TLRs on the Eastern Interconnection. Granting of transmission services based on non-simultaneous contract path transfer capabilities were often found as source of these grid over-subscription problems. In fact, the EPRI TagNet survey revealed the North to South (10,000mw+), West to East (10,000mw+), South to North (8000mw+) heavy transfer levels were commonly found during the past few years. TVA participated as co-chair on the Pre-season Security Assessment Study Team (PSAST), and used the On-Line TRACE tool to identify potential constraints for each transfer pattern. The identified constraints help system operators to closely monitor and provide operating procedures/remedial actions to resolve any Operating Security Limit Violation (OSLV). TVA has purchased an On - Line TRACE software license and is implementing on line TRACE simultaneous transfer analysis in the ROC.

PowerWorld Real Time Retriever

TVA has implemented the PowerWorld ReTriever Real-Time Monitoring System. This flow-based visualization tool is designed to help system operators and reliability personnel to monitor and display the current state of the system and raise alarms when conditions of concern are detected. Real time SCADA input is converted into easy to understand voltage contour and MW/MVAR flow arrows. System Operators are then able to monitor the health of TVA's transmission system with a glance. This user friendly visualization tool allows the user to enable a variety of system health indicators and create an easy-to-read, visually appealing and easy to understand display.

6.2 Flow-Based Tools and Procedures Developed in the Sub-region (continued)

IDC - Interchange Distribution Calculator

In support of the NERC TLR congestion management methodology and policy, TVA uses IDC as a flow-based tool to manage congestion and thereby adhere to NERC's TLR policy and procedures. The IDC principal program components are: transaction source and sink input, transaction database, transmission grid PTDFs (Power Transfer Distribution Factor) matrix, flow-gate information output, transmission loading relief calculations, congestion management, reallocation and curtailment notification. IDC is installed at each of the Eastern Interconnection Reliability Coordinator centers via frame relay connection or dial up. The Control Areas (CA) within each Reliability Area (RA) will continue to be the first line of defense for monitoring loading on their respective transmission systems. The NERC TLR procedure is initiated by a Reliability Coordinator (RC) at the RC's own request, upon the request of a Transmission Provider (TP) to its RC, or upon the request of a CA to its RC. When transmission relief is required, the RC will notify CAs within its Reliability Area of the required curtailments and will notify RCs outside its Reliability area of the required curtailments through their respective CAs. Description of the Sub-region Generation and Transmission System

6.3 Description of the Sub-Region Generation and Transmission System

Approximate Generating Capacity

AECI –	3,400 MW
BREC –	1,400 MW
EKPC –	2,300 MW
TVA –	30,000 MW
IPPs –	6,000 MW
Total –	**43,100 MW**

AECI Participating Transmission Facilities

1. 69kV includes radial lines but no distribution load stations
2. 161kV excludes 161kV distribution subs owned by our member cooperatives
3. GSU transformers and auxiliary equipment are not included

TVA Participating Transmission Facilities

1. All 500KV lines and substation equipment
2. All 345KV lines and substation equipment
3. All 230KV lines and substation equipment
4. All 161KV lines and substation equipment
5. All 138KV lines and substation equipment
6. All 115KV lines and substation equipment
7. All 69KV lines and substation equipment
8. All 46KV transmission facilities
9. GSU transformers and auxiliary equipment are not included

Big Rivers Participating Transmission Facilities

1. 345 kV transmission facilities
2. 161 kV transmission facilities
3. 138 kV transmission facilities
4. 69 kV transmission facilities
5. GSU transformers and auxiliary equipment are not included

TVA Participating Transmission Facilities (continued)

East Kentucky Power Corp. Participating Transmission Facilities

1. 345 kV transmission facilities
2. 138 kV transmission facilities
3. 161 kV transmission facilities
4. 69 kV transmission facilities
5. Includes existing radials and generation step-up transformers.
6. Does not include any distribution substations

6.4 Sub-region ATC Calculation Methodology

A. FIST – FIST provides advanced information on potential impacts of schedules on key flow-gates on the Eastern Interconnection. Scheduling information is made available to Reliability Coordinators, Transmission Providers, Control Areas, and most importantly, Power Serving Entities. FIST leverages from existing IDC capabilities and applies the same models to analyze transaction schedules that are used for Transmission Loading Relief procedures. FIST examines transactional impacts for the whole Eastern Interconnection and provides better coordination of schedules, thus improving ATC coordination. FIST shows remaining capacity on a flow-gate and distinguishes flow-gate loading by priority (Point To Point vs. network uses) for the current hour to the next 36 hours. FIST allows the market participants to proactively help reliability by responding to congestion conditions voluntarily

B. Power Flow Model – Power-flow models used in this analysis are the same models that are built on a regional basis for use by the region and the transmission providers to assess transfer capability. Since this model is being used to calculate incremental flows only, the power-flow model used in the impact calculation need only reflect the correct connectivity of the power system

C. Transmission Outage Schedule - To reflect the correct connectivity at any given time, the power-flow model is modified to reflect the current transmission outage schedule. Transmission outage schedule data is provided to the Sub-region Center on a continual basis. The outage schedule can be updated at any time.

6.5 ATC Coordination

Efforts are currently under way to develop common models with SETRAN in order to coordinate ATC calculations. Efforts are also being made with MISO to exchange data and to coordinate ATC.

Following are examples of current coordination activities.

6.5.1 Intra-regional

- 3:00 am Operators' Conference Call
- SERC FTP site
- SERC ATC Working Group

6.5.2 Interregional

- NERC/MAIN Morning Conference Call
- NERC ATC Coordination Working Group
- MISO FTP Site
- PSAST Study Team

6.6 Ongoing Developments

Advanced Applications

Procurement and implementation of Advanced Applications is underway. Initial implementation is scheduled for January 2004. The functions to be included in this software are: State Estimator, Real-Time Load Flow, Contingency Analysis, Optimal Power Flow, and Stability Analysis for the entire TVA Reliability Area footprint.

Standard Market Design

TVA is investigating SMD implementation.

7.0 CONSTRAINED INTERFACES (FLOWGATES)

Dynamic stability, voltage stability, steady-state voltage, as well as thermal constraints limit transfer capability in the Sub-region. Flow-gates are chosen as an indicator (or proxy) of the limiting phenomenon. The limiting phenomenon is translated into a TTC on these Flow-gates.

7.1 Intra-regional:

TVA performs daily, weekly, and monthly load flow studies with appropriate load forecast, transmission and generation outages, transmission reservation and schedule transactions. The end result is a list of internal Sub-region constrained flow-gates for current day to thirteen months (Summer and Winter seasons). Operating procedures are developed for the TVA Reliability footprint on these expected constrained facilities. A list of these real time constraints are added to the TVA TeleGyr real time monitoring pages.

7.2 Interregional:

TVA participates in SERC and NERC reliability study groups:

SERC VST/VAST Study Groups coordinate with SERC members and identify winter and summer flow-gates.

NERC Regional Reliability Study Groups coordinate with NERC members and identify winter and summer flow-gates.

8.0 SUB-REGION RELIABILITY MANUAL

The Sub-region Reliability Manual is currently under development.

The purpose of the Manual will be to acknowledge the reliability procedures at the Sub-region level and to provide guidance for the Sub-region Member committees and subcommittees. The responsibilities and processes of the Sub-region Operating Committee (OC) will also be delineated within the Manual. It will reflect that the OC and its subcommittees have direct responsibility for developing and maintaining the Sub-region's reliability procedures and that the OC will be responsible for the Manual and its content.

The Manual will assume the reader has an understanding of the Sub-region Operating Agreement and the applicable NERC Operating Policies. .

9.0 EMERGENCY AND RESTORATION PLANS AND PROCEDURES

The TVA RC is responsible for coordinating the implementation of emergency and restoration plans and procedures among the Members. The Members have Emergency and Restoration Plans and Procedures on file with the TVA RC. The Operating Committee periodically reviews these documents and makes recommendations as applicable.

Emergency communications between the RC and Member are initiated by either the TVA RC or the Member. Communications to external Reliability Authorities are usually initiated by the TVA RC through the RCIS. Assistance from external entities shall be coordinated through the TVA RC.

Appendix E contains the Sub-Region Emergency Reference documents and the individual Member Emergency Procedures and Restoration Plans.

10.0 SUB-REGION TRANSMISSION POLICIES AND PROCEDURES

The Transmission Providers in the TVA Reliability Area operate autonomously. Each TP has its own Open Access Transmission Tariff. The Sub-region Operating Committee is responsible for coordinating the implementation of the policies and operating procedures. Each TP's OATT is contained in Appendix F, and a list of operating procedures is contained in Appendix D.

11.0 SUB-REGION COMMUNICATIONS

The primary means of communication used by the TVA Reliability Coordinator for the Sub-region include:

- Public access telephone
- Ring-down circuits
- Satellite phone
- e-mail
- NERC SDX
- NERC IDC
- NERC RCIS
- NERC Hotline

11.0 SUB-REGION COMMUNICATIONS (continued)

- SERC Hotline
- SERC FTP site
- MISO FTP site
- ppRTG web site

12.0 ACRONYMS

ACE - Area Control Error

ATC - Available Transmission Capability

AECI - Associated Electric Coop, Inc.

BREC - Big Rivers Electric Corp.

ECAR - East Central Area Reliability Coordination (NERC)

EEA - Energy Emergency Alert

EKPC - East Kentucky Power Coop, Inc.

EPRI - Electric Power Research Institute

ICCP – Inter-control Center Communications Protocol

IDC - Interchange Distribution Calculator

IPP - Independent Power Producer

ISN - Interregional Security Network

MISO – Midwest Independent System Operator

MUST - Maximize Utilization of System Transmission

NAERO - North American Electric Reliability Organization

NERC - North American Electric Reliability Council

OASIS - Open Access Same-Time Information System

OATT - Open Access Transmissioin Tarriff

OC - Operating Committee of the Sub-region

ppRTG - public power Regional Transmission Grid

PSAST – Pre-season Security Assessment Study Team

PSSE - Power System Simulator Electrical

12.0 ACRONYMS (continued)

PTI - Power Technologies, Inc

RA - Reliability Authority

RC - Reliability Coordinator

RCIS - Reliability Coordinator Information System

ROC – Regional Operations Center

RTCA - Real Time Contingency Analysis

RTFCA - Real-Time First Contingency Analysis

SCADA - Supervisory Control and Data Acquisition

SCN - Sub-region Communications Network

SDX - System Data Exchange

SE - State Estimator

SERC - Southeastern Electric Reliability Council (NERC)

SETRAN – Southeast Transmission

SOC – System Operations Center

TLR - Transmission Loading Relief (NERC)

TLTG - PTI Software Used To Calculate Transmission Transfer Capability

TRACE - Transfer Capability Evaluation

TTC - Total Transfer Capability

TVA - Tennessee Valley Authority

13.0 DATA CONFIDENTIALITY AGREEMENT

All operating entities (members) in the TVA Reliability sub-region that receive operational data from and through the TVA RC shall be signatories to the NERC Data Confidentiality Agreement, as required by the Reliability/Security Coordination Agreements signed by the members. The current list of list of signatories can be found on the NERC web-site at:

ftp://www.nerc.com/pub/sys/all_updl/oc/scs/signator.pdf

Appendix A
(Page 1 of 1)

TVA Sub-Region Members

Control Areas
TVA (Public Utility)
AECI (Cooperative)
BREC (Cooperative)
EKPC (Cooperative)

Independent Power Producers	Control Area
Red Hills	TVA
Batesville Generation	BCA/TVA
Brownsville Power	TVA
Caledonia Power I	TVA
New Albany Power I	DEAM
Gleason Power	AEGL
Duke Energy Marshall	DEMK
Duke Energy "Looper's Farm"	DEMT/SOCO
Decatur Energy Center	TVA
Bolivar	TVA

Appendix B
(Page 1 of 2)

ECAR Requirments

1. The TVA Reliability Authority will offer Reliability Coordinator services to the ECAR Control Areas of EKPC and BREC for a fee.
2. The TVA Reliability Coordinator will participate in the daily morning conference calls of all Reliability Coordinators representing ECAR Control Areas.
3. The TVA Reliability Coordinator will participate in the decisions to make investigations of incidents as part of the NERC mandatory compliance program. These decisions are made during the morning Reliability Coordinator conference call.
4. TVA will become an associate member of ECAR.
5. TVA will participate in the effort being undertaken by ECAR to develop a data reporting system that will provide all Reliability Coordinators representing ECAR members and the ECAR Office data used for operating reports.
6. TVA will participate in the effort to develop a hotline that can be used by all ECAR Control Areas and by all Reliability Coordinators representing ECAR Control Areas.
7. TVA will perform the (1) frequency and ACE monitoring and (2) Control Area notifications required to administer the Inadvertent Monitoring required by the ECAR Inadvertent Settlement Procedure.
8. TVA will not participate in the ECAR Automatic Reserve Sharing System, however, EKPC and BREC will continue to participate in the ECAR ARS.

ECAR Inadvertent Settlement Procedure

Rational
ECAR's Inadvertent Settlement (IS) procedure provides a mechanism for dealing with Inadvertent Interchange that jeopardizes the reliability of the Eastern Interconnection and would apply, initially, to control areas within ECAR. The IS Tariff applies only to inadvertent interchange transactions among ECAR parties when the frequency of the Eastern Interconnection is low. Previously, the control areas balanced inadvertent interchanges by returns-in-kind. In other words, the control area drawing power from the grid could return power to the grid, even if the market rates for power during the return period were much lower. The IS Tariff is intended to remedy this problem.

TVA Reliability System Operator Action
The Inadvertent Settlement Procedure is triggered when the hourly average Eastern Interconnection Frequency has been below 59.97 Hz for two successive hours. The Inadvertent Settlement Procedure will then be in effect from the first hour of low frequency until the average Eastern Interconnection frequency recovers to 59.98 Hz.

BREC and EKPC Control Area Operators will be notified by the TVA Reliability Coordinator when the 1 hour average of Frequency is below 59.97 Hz. The message to the BREC and EKPC operators shall be:

Appendix B
(Page 2 of 2)

ECAR Requirments

"The ECAR Inadvertent may go into effect. Frequency is low, and the average 1 hour frequency is xx.xx Hz".

BREC and EKPC Control Area Operators will be notified by the TVA Reliability Coordinator when the 1 hour average of Frequency recovers to 59.98 Hz. The message to the BREC and EKPC operators shall be:
"The Frequency has recovered. The average 1 hour frequency is xx.xx Hz".

After the Fact Settlement
After the frequency reduction ends, ECAR will collect data and use that information to establish which control areas were out of balance during the frequency reduction. The IS Tariff calls for the ECAR parties that drew power from the grid (Short Party) to compensate the parties that made up the shortfall (Long Party) at the higher of incremental cost or highest sales price of the Long Party during the applicable hour, plus a 10% adder to promote appropriate behavior. A $15/Mwh credit will be applied to the dollar amount as a proxy for returning energy off peak.

Reliability is a critical function that is the responsibility of each reliability council. ECAR has determined that the existing return-in-kind practice created an incentive for one control area in ECAR to place the reliability of the Eastern Interconnection at risk by not purchasing power at prevailing market rates or shedding load when it lacked sufficient resources to meet its obligations. ECAR, on behalf of its members, has developed measures that should eliminate the economic incentives that contributed to the summer 1999 frequency crisis and reliability problems.

Appendix C
(Page 1 of 1)

Reliability Coordination Agreements

The operating entities in the TVA Reliability Sub-region that are subject to the directives of the TVA RC have each signed a Reliability Coordination Agreement. These agreements contain proprietary information and are therefore made available only on a need to know basis. They are on file with the TVA RC.

The ppRTG members are under the agreement titled “Security Coordination Agreement.”

The IPP members are under the agreement titled “Reliability Coordination Agreement for the Sub-region of the Southeastern Electric Reliability Council.”

Appendix D
(Page 1 of 1)

Operating Procedures

The following are examples of operating procedures used in the TVA Reliability Area. These procedures may contain proprietary information, and therefore are made available only on a need to know basis. They are on file with the TVA RC.

1. Transmission Provider's Local Procedures (TVA/Southern Interface)
2. Transmission Order Of Curtailment
3. Reconfiguration and Redispatch, General Process
4. Radnor-Nolensville Line Procedure
5. Paradise Operating Procedure
6. Notification Procedure For Transmission Reliability Problems
7. Entergy and AECI Reserve Sharing Agreement
8. EEA Procedure
9. ECAR Automatic Reserve Sharing
10. ECAR Inadvertent Settlement Procedure
11. Santeetlah-Robbinsville (Duke Interface) Procedure
12. Davidson-Grassland Procedure
13. Cumberland Interim Procedure
14. Cumberland Procedure
15. Operational Desk Responsibilities and Communications
16. Bull Run – Volunteer Procedure
17. Bullitt – Blue Lick Procedure

Appendix E
(Page 1 of 1)

Emergency and Restoration Plans and Procedures

These plans and procedures contain system sensitive information and are therefore made available only on a need to know basis. They include:

TVA:
- Black Start Procedures
- Electrical Load Curtailment Plan

AECI:
- Emergency Operating Plan
- Electric System Restoration Plan

Big Rivers:
- Emergency Operations and Restoration Plans
- Emergency Operations and Restoration Procedures

EKPC:
- Black Start Procedures
- Under Frequency Load Shedding Procedures

Appendix F
(Page 1 of 1)

Open Access Transmission Tarriffs

1. TVA Transmission Service Guidelines
2. AECI Open Access Transmission Tariff
3. EKPC Open Access Transmission Tariff
4. BREC Open Access Transmission Tariff

These documents can be downloaded from the respective OASIS sites.

RELIABILITY PLAN

for the

TVA Reliability Coordinator Area

TENNESSEE VALLEY AUTHORITY
RELIABILITY COORDINATOR

October 4, 2005

Change History

07/13/04	Complete re-write to align with revised NERC Policy 9 (approved by NERC 06/15/04) and update footprint.
10/04/05	Updated information and revised to align w/NERC Standards. Updated with applicable ESO Standard Processes & Procedures.

TABLE OF CONTENTS

Introduction

The North American Electric Reliability Council (NERC) requires every Region, Sub-region, or interregional coordinating group to establish a Reliability Coordinator to provide the reliability assessment and emergency operations coordination for the Balancing Authorities and Transmission Operators within the Regions and across the Regional boundaries.

The Tennessee Valley Authority (TVA) is recognized by the Southeastern Electric Reliability Council (SERC) as the Reliability Coordinator for the TVA Sub-Region of SERC. TVA has also entered into Reliability Coordination Agreements (Agreements) with other Balancing Authorities and Transmission Operators (herein referred to as "Members") to perform the NERC-required Reliability Coordinator function for them. The Members operate as Balancing Authorities and/or Transmission Operators in East Central Area Reliability Coordination Agreement (ECAR), Mid-America Interconnected Network, Inc. (MAIN), and SERC regions. The respective region recognizes TVA as the Reliability Coordinator for the applicable Member. The TVA Reliability Coordinator Area consists of the transmission and generation facilities within the Balancing Authorities' metered boundaries for the Members listed in Appendix A. The term "Member" also includes TVA Balancing Authority and Transmission Operator functions.

The TVA Reliability Coordinator (RC) is responsible for the TVA Reliability Coordinator Area bulk transmission reliability and power supply reliability. Bulk transmission reliability functions include reliability analysis, loading relief procedures, re-dispatch of generation and ordering curtailment of transactions and/or load. Power supply reliability entails monitoring Balancing Area performance and directing the Balancing Authorities and Transmission Operators to take actions, including load curtailment and increasing/decreasing generation in situations where an imbalance between generation and load places the system in jeopardy. TVA RC reliability procedures and policies are consistent with those of NERC. TVA Reliability Coordinator Area Members operate in various NERC Regions and TVA RC recognizes each applicable Region's policies and standards (also see Appendix B).

This document represents the Reliability Plan for the TVA Reliability Coordinator Area.

The previous TVA Sub-Region Reliability Plan (dated 11/05/02) is posted at www.nerc.com/~filez/reliaplans.html. Upon approval of the NERC Operating Committee this plan will supersede the previous plan.

[Each NERC standard requirement applicable to the RC is referenced. Applicable TVA Standards, Processes and Procedures are also referenced.]

A. Responsibilities – Authorization

Each Regional Reliability Organization, subregion, or interregional coordinating group shall establish one or more Reliability Coordinators to continuously assess transmission reliability and coordinate emergency operations among the operating entities within the region and across the regional boundaries. TVA RC is responsible for the reliable operation of the TVA RC Area. The TVA RC Area is composed of the Members listed in Appendix A. [IRO-001-0, R1]

TVA RC complies with a regional reliability plan approved by the NERC Operating Committee. [IRO-001-0, R2]

TVA RC has clear decision-making authority to act and to direct actions to be taken by Balancing Authorities and Transmission Operators within its Reliability Coordinator Area to preserve the integrity and reliability of the Bulk Electric System. [IRO-001-0, R3] (ESO-RA-SOP-10.204, Transmission Reliability Order of Curtailment) TVA RC responsibilities and authority are clearly defined in the executed Reliability Coordination Agreements.

TVA RC has clear, comprehensive coordination agreements with adjacent Reliability Coordinators to ensure that System Operating Limit or Interconnection Reliability Operating Limit violation mitigation requiring actions in adjacent Reliability Coordinator Areas are coordinated. [IRO-001-0, R7] Appendix C lists the status of adjacent Reliability Coordination Agreements.

TVA RC will act in the interests of reliability for the overall Reliability Coordinator Area and the Interconnection before the interests of any other entity. [IRO-001-0, R9]

B. Responsibilities – Delegation of Tasks

TVA RC has not delegated any tasks. [IRO-001-0, R4, R5, R6]

C. Common Tasks for Next-Day and Current-Day Operations

TVA RC assesses contingency situations as described in sections below for Current-Day and Next-Day operations. TVA RC monitors all Bulk Electric System facilities within its own Reliability Coordinator Area and adjacent Reliability Coordinator Areas, as necessary, to determine any potential System Operating Limit and Interconnection Reliability Operating Limit violations within its Reliability Coordinator Area, regardless of prior planned or unplanned events. [IRO-003-0, R1] (ESO-RA-TP-09.200, Load Flow Studies)

C. Common Tasks for Next-Day and Current-Day Operations (Continued)

TVA RC contacts neighboring Reliability Coordinator areas when TVA RC is aware of an operational concern, such as declining voltages, excessive reactive flows, or an IROL violation, in a neighboring RC Area. TVA and neighboring Reliability Coordinators coordinate any actions, including emergency assistance, required to mitigate the operational concern. [IRO-003-0, R2] (ESO-RA-SOP-10.214 Procedure for Hotline Calls)

TVA RC performs analysis and monitoring (as described in the appropriate sections below) and monitors the status of all critical facilities whose failure, degradation, or disconnection could result in any SOL or IROL violation. TVA RC ensures that other Balancing Authorities and Transmission Operators within its RC Area always operate under known and studied conditions and do not burden others. TVA RC knows the status of all facilities that may be required to assist area restoration objectives. TVA RC directs action to reposition the power system and restore area restoration objectives following contingency events within approved timelines. [IRO-003-0, R3]

TVA RC issues directives in a clear, concise, and definitive manner, ensures the recipient of the directive repeats the information back correctly, and acknowledges the response as correct or repeats the original statement to resolve any misunderstandings. [COM-002-0, R3] (ESO-VP-SDP 10.003, Communications Protocol; and ESO-RA-SOP-10.214, Procedure for Hotline Calls)

Each Transmission Operator and Balancing Authority provides the TVA RC with the operating data that the TVA RC requires to perform operational reliability assessments and to coordinate reliable operations within the TVA Reliability Coordinator Area. [TOP-005-0, R1]

TVA RC has identified the data requirements from the list in Attachment 1-TOP-005-0 “Electric System Reliability Data” and any additional operating information requirements relating to operation of the bulk power system within the TVA Reliability Coordinator Area. [TOP-005-0, R1.1]

TVA RC, via the ISN or equivalent system, exchanges with other Reliability Coordinators operating data that are necessary to allow the Reliability Coordinators to perform operational reliability assessments and coordinate reliable operations. TVA RC does share with other Reliability Coordinators the types of data listed in Attachment 1-TOP-005-0 “Electric System Reliability Data,” unless otherwise agreed to. [TOP-005-0, R3]

D. Next-Day Operations

TVA RC conducts next-day reliability analyses for its Reliability Coordinator Area to ensure that the Bulk Electric System can be operated reliably in anticipated normal and contingency event conditions. TVA RC conducts contingency analysis studies to identify potential interface and other SOL and IROL violations, including overloaded transmission lines and transformers, voltage and stability limits, etc. [IRO-004-0, R1]

TVA RC pays particular attention to parallel flows to ensure that the TVA Reliability Coordinator Area does not place an unacceptable or undue Burden on adjacent Reliability Coordinator Areas. [IRO-004-0, R2]

TVA RC, in conjunction with other Members within its Reliability Coordinator Area, develops required action plans, including reconfiguration of the transmission system, re-dispatching of generation, reduction or curtailment of Interchange Transactions, or reducing load to return transmission loading to within acceptable SOLs or IROLs. [IRO-004-0, R3]

Each Member in the TVA Reliability Coordinator Area provides information required for system studies, such as critical facility status, load, generation, operating reserve projections, and known Interchange Transactions. This information is made available by 1200 Central Standard Time. [IRO-004-0, R4] TVA RC and its Members utilize the NERC System Data Exchange (SDX).

TVA RC shares the results of its system studies, when conditions warrant or upon request, with other Reliability Coordinators and with Balancing Authorities and Transmission Operators within the TVA Reliability Coordinator Area. The TVA Reliability Coordinator makes study results available no later than 1500 Central Standard Time, unless circumstances warrant otherwise. [IRO-004-0, R5]

When conditions warrant, the TVA RC initiates conference calls or other appropriate communications to address the results of its reliability analyses. [IRO-004-0, R6]

If the results of these studies indicate potential SOL or IROL violations, the TVA RC issues appropriate alerts via the Reliability Coordinator Information System (RCIS) and directs Members in the TVA Reliability Coordinator area to take any necessary action the TVA RC Reliability Coordinator deems appropriate to address the potential SOL or IROL violation. [IRO-004-0, R7] TVA RC resolves any scheduling of potential reliability conflicts. [TOP-003-0, R4]

D. Next-Day Operations (Continued)

Each Member in the TVA Reliability Coordinator Area will comply with the directives of the TVA RC based on the next day assessments in the same manner in which it would comply during real time operating events. [IRO-004-0, R8]

E. Current-Day Operations

TVA RC monitors applicable transmission line status, real and reactive power flows, voltage, load-tap-changer settings, and status of rotating and static reactive resources. [TOP-006-0, R2]

TVA RC monitors its Reliability Coordinator Area parameters, including, but not limited to the following: [IRO-005-0, R1]

- Current status of Bulk Electric System elements and system loading. [IRO-005-0, R1.1]
- Current pre-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. [IRO-005-0, R1.2]
- Current post-contingency element conditions (voltage, thermal, or stability), including any applicable mitigation plans to alleviate SOL or IROL violations, including the plan's viability and scope. [IRO-005-0, R1.3]
- System real and reactive reserves (actual versus required). [IRO-005-0, R1.4]
- Capacity and energy adequacy conditions. [IRO-005-0, R1.5]
- Current ACE for all Balancing Authorities. [IRO-005-0, R1.6]
- Current local or Transmission Loading Relief procedures in effect. [IRO-005-0, R1.7]
- Planned generation dispatches. [IRO-005-0, R1.8]
- Planned transmission or generation outages. [IRO-005-0, R1.9]
- Contingency events. [IRO-005-0, R1.10]

TVA RC has knowledge of current and planned critical facility status through monitoring of key facilities across the TVA RC Area via real-time and near real-time data sent to the TVA RC by the Members. Planned facility status is communicated via teleconferences and System Data Exchange (SDX).

TVA RC has implemented the PowerWorld ReTriever Real-Time Monitoring System. This flow based visualization tool is designed to help system operators and reliability personnel monitor and display the current state of the system and raise alarms when conditions of concern are detected. Real time SCADA input is converted to easy to understand voltage contour and MW/MVAR flow arrows. TVA

RC System Operators are able to monitor the health of TVA's RC Area transmission system (and neighboring areas) with a glance. This user friendly visualization tool allows the user to enable a variety of health indicators and create an easy-to-read, visually appealing and easy to understand display for the wide area view.

TVA RC utilizes power flow software to determine line outage distribution factors and applies these factors to critical flow gates. The RC System Operator then monitors these critical facilities and their contingent elements in real time.

TVA has a state estimator / contingency analysis tool as part of its Telegyr EMS. TVA also has a separate AREVA real-time state estimator and security analysis package (Advanced Network Applications). The AREVA model has approximately 5000 buses. Node/breaker detail is provided for the TVA RC area. Real-time contingency analysis cycles every five minutes.

TVA RC does provide appropriate technical information concerning protective relays to their operating personnel. [TOP-006-0, R3]

TVA RC does have information, including weather forecasts and past load patterns, available to predict the system's near-term load pattern. [TOP-006-0, R4]

TVA RC does use monitoring equipment to bring to the attention of operating personnel important deviations in operating conditions and to indicate, if appropriate, the need for corrective action. [TOP-006-0, R5]TVA's EMS system also provides alarms for designated facilities, flowgates, and calculated post-contingency flows.

TVA RC is aware of all Interchange Transactions that wheel through, source, or sink in the TVA Reliability Coordinator Area, and that Interchange Transaction information is available to all Reliability Coordinators in the Eastern Interconnection via the NERC Interchange Distribution Calculator (IDC). [IRO-005-0, R2]

As portions of the transmission system approach or exceed SOLs or IROLs, the TVA RC works with Members in the TVA Reliability Coordination Area to evaluate and assess any additional Interchange Schedules that would violate those limits. If a potential or actual IROL violation cannot be avoided through proactive intervention, the TVA RC will initiate control actions or emergency procedures to relieve the violation without delay, and no longer than 30 minutes. The TVA RC ensures that all resources, including load shedding, are available to address a potential or actual IROL violation. [IRO-005-0, R3]

TVA RC monitors its Balancing Authorities' parameters to ensure that the required amount of operating reserves is provided and available as required to meet the Control Performance Standard and Disturbance Control Standard requirements. If necessary, the TVA RC will direct the Balancing Authorities in its Reliability Coordinator Area to arrange for assistance from neighboring Balancing Authorities. The TVA RC issues Energy Emergency Alerts as needed and at the request of its Members. [IRO-005-0, R4]

AECI participates in the SPP Reserve Sharing Pool. BREC and EKPC participate in the ECAR Reserve Sharing Pool. EEI participates in the MAIN Reserve Sharing Pool. TVA Balancing Authority requirements for operating reserves are specified in these documents: Contingency Reserve Requirements ESO-BA-SOP-10.303; Regulating Reserve Standard ESO-BA-SOP-10.306.

TVA RC will identify the cause of any potential or actual SOL or IROL violations. The TVA RC will initiate the control action or emergency procedure to relieve the potential or actual IROL violation without delay, and no longer than 30 minutes. The TVA RC will utilize all resources, including load shedding, to address an IROL violation. [IRO-005-0, R5] (ESO-RA-SOP-10.204 Transmission Reliability Order of Curtailment)

TVA RC ensures its Members are aware of Geo-Magnetic Disturbance (GMD) forecast information and assists as needed in the development of any required response plans. [IRO-005-0, R6]

TVA RC participates in NERC hotline discussions, assists in the assessment of reliability of the overall interconnected system, and coordinates actions in anticipated or actual emergency situations. The TVA RC will disseminate such information within its Reliability Coordinator Area, as required. [IRO-005-0, R7] (ESO-RA-SOP-10.214 Procedure for Hotline Calls)

TVA RC monitors system frequency and it's Balancing Authorities' performance and directs any necessary rebalancing to return to CPS and DCS compliance. The Members will utilize all resources, including firm load shedding, as directed by the TVA RC to relieve an emergent condition. [IRO-005-0, R8]

TVA RC does monitor system frequency. [TOP-006-0, R7]

Frequency used in the TVA Balancing Authority's ACE calculation is from one of four sources in two geographic locations within the TVA Balancing Authority. The two primary feeds are true-time frequency devices, monitored in the Chattanooga area from the Electric Power Board (EPB), one at the Regional Operations Center (ROC) and the other at the System Operations Center (SOC). The feeds will automatically failover, to the other, if one fails. Two additional back-up frequency devices provide signals to the ROC. These signals are known as Analog Back-up's (ABU), and they are connected at the Chickamauga Dam, which can be isolated on a back-up generator, and the other at Occidental (near real time metering location) in the Muscle Shoals area. Frequency indication from several substations across the TVA Balancing Authority area is shown in TVA's EMS.

Each of the other Balancing Authorities within the Reliability Area provides a frequency data value which is monitored via TVA's EMS.

All Balancing Authorities' frequency values are displayed via the RCIS. The CERTS Wide-Area Real Time ACE-Frequency Monitoring System provides visualization of Balancing Authorities ACE.

TVA is enhancing its real time monitoring capabilities with Phasor Monitoring Units (PMUs). TVA is participating in the DOE/CERTS program to install PMUs throughout the Eastern Interconnection, and is hosting the data concentrator for that effort. Since PMUs provide higher frequency information than RTUs and since the PMU data is accurately time tagged through GPS, the information will be used in the future as an augmentation of state estimator inputs as well as a separate presentation of system conditions. The Real-Time Dynamics Monitoring system displays the PMU data (voltage, current, frequency, and angle) and is independent of the TVA EMS.

The TVA RC coordinates with other Reliability Coordinators and its Members as needed to develop and implement action plans to mitigate potential or actual SOL, IROL, CPS, or DCS violations. The TVA RC coordinates pending generation and transmission maintenance outages with other Reliability Coordinators and Transmission Operators, Balancing Authorities, and Generator Operators as needed in both the real time and next-day reliability analysis timeframes. [IRO-005-0, R9]

As necessary, the TVA RC assists the Balancing Authorities in its Reliability Coordinator Area in arranging for assistance from neighboring Reliability Coordinator Areas or Balancing Authorities. [IRO-005-0, R10]

E. Current-Day Operations (Continued)

The TVA RC monitors ACE for each Balancing Authority within the TVA RC Area and identifies sources of large Area Control Errors that may be contributing to Frequency Error, Time Error, or Inadvertent Interchange and discusses corrective actions with appropriate Balancing Authorities. If a Frequency Error, Time Error, or inadvertent problem occurs outside of the TVA Reliability Coordinator Area, the TVA RC will initiate a NERC hotline call to discuss the Frequency Error, Time Error, or Inadvertent Interchange with other Reliability Coordinators. The TVA RC directs its Balancing Authorities to comply with CPS and DCS. [IRO-005-0, R11]

Whenever a Special Protection System that may have an inter-Balancing Authority, inter-Transmission Operator, or inter-Reliability Coordinator Area impact (e.g., could potentially affect transmission flows resulting in a SOL or IROL violation) is armed, the TVA RC will be aware of the impact of the operation of that Special Protection System on inter-area flows. The Member will immediately inform the TVA RC of the status of the Special Protection System including any degradation or potential failure to operate as expected. [IRO-005-0, R12] There are not any Special Protection Systems in the TVA RC Area.

TVA RC ensures that Members operate to prevent the likelihood that a disturbance, action, or non-action in its Reliability Coordinator Area will result in a SOL or IROL violation in another area of the Interconnection. In instances where there is a difference in derived limits, the TVA RC and Members shall always operate the Bulk Electric System to the most limiting parameter. [IRO-005-0, R13]

TVA RC makes known to its Members within its Reliability Coordinator Area the SOLs or IROLs within its wide-area view. [IRO-005-0, R14]

TVA RC foreseeing a transmission problem (such as an SOL or IROL violation, loss of reactive reserves, etc.) within its Reliability Coordinator Area will issue an alert to all impacted Members in its Reliability Coordinator Area, and all impacted Reliability Coordinators within the Interconnection via the Reliability Coordinator Information System (RCIS) without delay. The receiving Reliability Coordinator will disseminate this information to its impacted Members. The TVA RC will notify all impacted Members and Reliability Coordinators when the transmission problem has been mitigated. [IRO-005-0, R15]

TVA RC confirms reliability assessment results and determines the effects within the TVA Reliability Area and adjacent Reliability Coordinator Areas. The TVA RC will discuss options to mitigate potential or actual SOL or IROL violations and take actions as necessary to always act in the best interests of the Interconnection. [IRO-005-0, R16]

When an IROL or SOL is exceeded, the TVA RC will evaluate the local and wide-area impacts, both real-time and post-contingency, and determine if the actions being taken are appropriate and sufficient to return the system to within IROL in thirty minutes. If the actions being taken are not appropriate or sufficient, the TVA RC will direct the Members to return the system to within IROL or SOL. [IRO-005-0, R17] (ESO-RA-SOP-10.204 Transmission Reliability Order of Curtailment)

TVA RC notifies its members of potential transmission problems by telephone. TVA notifies all RCs via RCIS or NERC Hotline as appropriate. TVA RC conducts a daily operational call with the Members to discuss reliability issues. TVA RC participates in conference calls with adjacent RCs.

Only a Reliability Coordinator is eligible to act as Interconnection Time Monitor. A single Reliability Coordinator in each Interconnection is designated by the NERC Operating Committee to serve as Interconnection Time Monitor. TVA RC is not currently the designated Interconnection Time Monitor. [BAL-004-0, R1]

TVA RC has the authority to request that the Interconnection Time Monitor terminate a Time Error Correction in progress, or a scheduled Time Error Correction that has not begun, for reliability considerations. [BAL-004-0, R4]

TVA RC communicates start and end times for time error corrections to the Balancing Authorities within its RC Area by telephone.

The TVA RC experiencing a potential or actual SOL or IROL violation within its Reliability Coordinator Area will, at its discretion, select from either a “local” (Regional, Interregional, or subregional) transmission loading relief procedure or an Interconnection-wide procedure. The Eastern Interconnection Transmission Loading Relief (TLR) procedure is available for use by the TVA RC. [IRO-006-0, R2]

TVA RC will evaluate actions taken to address an IROL or SOL violation and, if the actions taken are not appropriate or sufficient, direct actions required to return the system to within limits. [TOP-007-0, R4]

The TVA RC will use local transmission loading relief or congestion management procedures, provided the Transmission Operator experiencing the potential or actual SOL or IROL violation is a party to those procedures. [IRO-006-0, R3]

The TVA RC may implement a local transmission loading relief or congestion management procedure simultaneously with an Interconnection-wide procedure.

E. Current-Day Operations (Continued)

However, the TVA RC will follow the curtailments as directed by the Interconnection-wide procedure. If the TVA RC desired to use a local procedure as a substitute for curtailments as directed by the Interconnection-wide procedure, then it would have such use approved by the NERC Operating Committee. [IRO-006-0, R4]

When implemented, the TVA RC will comply with the provisions of the Interconnection-wide procedure including, for example, action by Reliability Coordinators in other Interconnections to curtail an Interchange Transaction that crosses an Interconnection boundary. [IRO-006-0, R5]

During the implementation of relief procedures, and up to the point that emergency action is necessary, the TVA RC and Balancing Authorities in the TVA Reliability Area will comply with interchange scheduling standards INT-001 through INT-004. [IRO-006-0, R6]

F. Emergency Operations

TVA RC and Balancing Authorities and Transmission Operators in the TVA Reliability Coordination Area will promptly analyze Bulk Electric System disturbances on its system or facilities. [EOP-004-0, R2]

TVA RC, Balancing Authorities and/or Transmission Operators in the TVA Reliability Coordination Area experiencing a reportable incident shall provide a preliminary written report to the applicable region and NERC. [EOP-004-0, R3]

- TVA RC and/or the affected Balancing Authorities and Transmission Operators in the TVA Reliability Coordination Area will submit within 24 hours of the disturbance or unusual occurrence either a copy of the report submitted to DOE, or, if no DOE report is required, a copy of the NERC Interconnection Reliability Operating Limit and Preliminary Disturbance Report form. Events that are not identified until some time after they occur shall be reported within 24 hours of being recognized. [EOP-004-0, R3.1]
- Applicable reporting forms are provided in NERC Standards Attachments 1-EOP-004-0 and 2-EOP-004-0. [EOP-004-0, R3.2]
- Under certain adverse conditions, e.g., severe weather, it may not be possible to assess the damage caused by a disturbance and issue a written Interconnection Reliability Operating Limit and Preliminary Disturbance Report within 24 hours. In such cases, the TVA RC, Balancing Authority, and/or Transmission Operator will promptly notify applicable regions and NERC, and verbally provide as much information as is available at that time. The TVA RC and the affected Balancing Authority and Transmission Operator will provide timely, periodic verbal updates until adequate information is available to issue a written Preliminary Disturbance Report. [EOP-004-0, R3.3]

F. Emergency Operations (Continued)

Documented Procedures include: ESO-CM-SPP-03.001 Reporting of Incidents, Threats, Disturbances, and Emergencies Within the TVA Control Area to Organizations External to TVA.

TVA RC has procedures for the recognition of and for making their operating personnel aware of sabotage events on its facilities and multi-site sabotage affecting larger portions of the Interconnection. [CIP-001-0, R1]

TVA RC has procedures for the communication of information concerning sabotage events to appropriate parties in the Interconnection. [CIP-001-0, R2]

TVA RC provides its operating personnel with sabotage response guidelines, including personnel to contact, for reporting disturbances due to sabotage events. [CIP-001-0, R3]

TVA RC has established communications contacts with local Federal Bureau of Investigation (FBI) officials and develops reporting procedures as appropriate to their circumstances. [CIP-001-0, R4] (TPS-SPP-14.005 Threat Alert Levels and Security Measures; ESO-CS-SPP-12.862 Electronic Incident Response; TPS-SPP-14.006 Bomb Threat; TPS-SPP-14.007 Reporting Suspicious People-Objects-Activities, ESO-CS-SPP-12.862 Electronic Incident Response)

TVA RC has the responsibility and clear decision-making authority to take whatever actions are needed to ensure the reliability of its respective area and shall exercise specific authority to alleviate capacity and energy emergencies. [EOP-002-0, R1]

TVA RC will direct its Members to implement their capacity and energy emergency plan, when required and as appropriate, to reduce risks to the interconnected system. [EOP-002-0, R2]

TVA RC will communicate its Members' current and future system conditions to neighboring areas if it experiences an operating capacity or energy emergency. [EOP-002-0, R4]

TVA RC experiencing a potential or actual Energy Emergency in its Reliability Area will initiate an Energy Emergency Alert as detailed in NERC Standard Attachment 1-EOP-002-0 "Energy Emergency Alert Levels." TVA RC will act to mitigate the emergency condition, including a request for emergency assistance if required. [EOP-002-0, R9]

When a Member expects to elevate the transmission service priority of an Interchange Transaction from Priority 6 (Network Integration Transmission Service from Non-designated Resources) to Priority 7 (Network Integration Transmission Service from designated Network Resources) as permitted in its transmission tariff: [EOP-002-0, R10]

- TVA RC will submit the report to NERC for posting on the NERC Website, noting the expected total MW that may have its transmission service priority changed. [EOP-002-0, R10.2]
- TVA RC will use EEA 1 to forecast the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7. [EOP-002-0, R10.3]
- TVA RC will use EEA 2 to announce the change of the priority of transmission service of an Interchange Transaction on the system from Priority 6 to Priority 7. [EOP-002-0, R10.4]

The TVA RC will take appropriate actions in accordance with established policies, procedures, authority, and expectations to relieve transmission loading. The document, Transmission Reliability Order of Curtailment outlines the process used by TVA RC regarding actions to be taken to relieve transmission loading issues. [IRO-006-0, R1] (ESO-RA-SOP-10.204 Transmission Reliability Order of Curtailment)

The TVA RC has a plan to continue reliability operations in the event its control center becomes inoperable. The contingency plan meets the following requirements: [EOP-008-0, R1]

- The contingency plan shall not rely on data or voice communication from the primary control facility to be viable. [EOP-008-0, R1.1]
- The plan shall include procedures and responsibilities for providing basic tie line control and procedures and for maintaining the status of all inter-area schedules, such that there is an hourly accounting of all schedules. [EOP-008-0, R1.2]
- The contingency plan must address monitoring and control of critical transmission facilities, generation control, voltage control, time and frequency control, control of critical substation devices, and logging of significant power system events. The plan shall list the critical facilities. [EOP-008-0, R1.3]
- The plan shall include procedures and responsibilities for maintaining basic voice communication capabilities with other areas. [EOP-008-0, R1.4]
- The plan shall include procedures and responsibilities for conducting periodic tests, at least annually, to ensure viability of the plan. [EOP-008-0, R1.5]
- The plan shall include procedures and responsibilities for providing annual training to ensure that operating personnel are able to implement the contingency plans. [EOP-008-0, R1.6]
- The plan shall be reviewed and updated annually. [EOP-008-0, R1.7]

F. Emergency Operations (Continued)

- Interim provisions must be included if it is expected to take more than one hour to implement the contingency plan for loss of primary control facility. [EOP-008-0, R1.8]

TVA operates two control centers, one for the Reliability Coordination functions and one for the Balancing Authority and Transmission Operator functions. The Regional Operations Center (ROC) is the main facility for the RC and TVA Transmission Provider/Interchange Authority functions. The System Operations Center (SOC) is the main facility for the TVA Balancing Authority and Transmission Operations. The SOC backs-up the ROC and the ROC backs-up the SOC. Both facilities are in a hot standby mode at all times. For the brief time it would take the Reliability Coordinator to relocate to the back-up center the SOC NERC certified System Operators would monitor the system. Each site utilizes the same type systems and has back-up power supplies, and fully redundant communications independent of each other. The transfer to the back-up center would be transparent to the outside world as a phone script rolls the RC's numbers from the ROC to the SOC. Once the RC is in place at the SOC a notice would be posted on the RCIS informing everyone that TVA RC had relocated to the back-up facility.

Additionally, TVA has a Reliability Engineer in both main control centers during normal business hours. TVA also has dedicated staff for emergency preparedness.

Documented Procedures include: TPS-SPP-14.004 Regional Operations Center (ROC) Emergency Evacuation Procedure; TPS-SPP-14.003 System Operations Center (SOC) Emergency Evacuation Procedure.

G. System Restoration

TVA RC is aware of the restoration plan of each Member in its Reliability Coordinator Area in accordance with NERC and regional requirements. [EOP-006-0, R1]

TVA RC will monitor restoration progress and coordinate any needed assistance. [EOP-006-0, R2]

TVA RC has a Reliability Coordinator Area restoration plan that provides coordination between individual Member restoration plans and that ensures reliability is maintained during system restoration events. [EOP-006-0, R3]

G. System Restoration (Continued)

TVA RC will serve as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Members not immediately involved in restoration. [EOP-006-0, R4]

TVA RC will approve, communicate, and coordinate the re-synchronizing of major system islands or synchronizing points so as not to cause a Burden on Members or adjacent Reliability Coordinator Areas. [EOP-006-0, R5]

TVA RC will take actions to restore normal operations once an operating emergency has been mitigated in accordance with its restoration plan. [EOP-006-0, R6]

The TVA RC is aware of each Members Restoration Plan and has a written copy of said plan in its possession. During system restoration, TVA RC monitors restoration progress and acts to coordinate any needed assistance. TVA RC serves as the primary contact for disseminating information regarding restoration to neighboring Reliability Coordinators and Members not immediately involved in restoration. TVA RC assists the Members in re-establishing normal system configuration and coordinate communications as required.

The member plans and procedures include:

AECI Emergency Operating Plan
AECI System Restoration Plan

BREC Emergency Operations/Restoration Plans
BREC Emergency Operating Procedures: Transmission Emergency
BREC System/Service Restoration Procedures

EEI Backup Control Center
EEI Imminent Station Blackout

EKPC Black Start Procedures
EKPC Restoration Plan
EKPC Underfrequency Load Shed Program

TVA Black Start Plan
TVA Transmission Emergency Plan.

H. Coordination Agreements and Data Sharing

TVA, Midwest ISO, and PJM have a Joint Reliability Coordination Agreement. [IRO-001-0, R7]

TVA RC and other adjacent RCs are in discussions regarding development of written coordination agreements.

TVA RC determines the data requirements to support its reliability coordination tasks and requests such data from Members or adjacent Reliability Coordinators. [IRO-002-0, R2]

TVA RC provides for data exchange with Members and Reliability Coordinators, Transmission Operators, and Balancing Authorities via a secure network. [IRO-002-0, R3]

TVA RC Area Members and other RCs provide data (via ISN and RCIS) as requested to support reliability coordination.

I. Facility

TVA performs the Reliability Coordinator function at the Regional Operations Center (ROC) located in Chattanooga, Tennessee. The ROC has the necessary voice and data communications links to appropriate entities within its Reliability Coordination Area for the TVA RC to perform their responsibilities. These communications facilities are staffed and available to act in addressing a real-time emergency condition. [IRO-002-0, R1]

TVA RC has multi-directional communications capabilities with its Members, and with neighboring Reliability Coordinators, for both voice and data exchange to meet reliability needs of the Interconnection. [IRO-002-0, R4]

TVA RC has detailed real-time monitoring capability of its Reliability Coordinator Area and sufficient monitoring capability of its surrounding Reliability Coordinator Areas to ensure that potential or actual System Operating Limit or Interconnection Reliability Operating Limit violations are identified. TVA RC has monitoring systems that provide information that is easily understood and interpreted by the Reliability Coordinator's operating personnel. Particular emphasis is given to alarm management and awareness systems, automated data transfers, and synchronized information systems, over a redundant and highly reliable infrastructure. [IRO-002-0, R5]

TVA RC monitors Bulk Electric System elements (generators, transmission lines, buses, transformers, breakers, etc.) that could result in SOL or IROL violations within its Reliability Coordinator Area. TVA's Reliability Coordinator monitors both real and reactive power system flows, and operating reserves, and the status of Bulk

Electric System elements that are, or could be, critical to SOLs and IROLs and system restoration requirements within its Reliability Coordinator Area. [IRO-002-0, R6]

TVA RC has adequate analysis tools, including state estimation, pre-and post-contingency analysis capabilities (thermal, stability, and voltage), and wide-area overview displays. TVA RC has detailed monitoring capability of the TVA Reliability Area and sufficient monitoring capability of the surrounding Reliability Areas to ensure potential reliability violations are identified. TVA RC continuously monitors key transmission facilities in its area in conjunction with the Members monitoring of local facilities and issues. TVA RC receives SCADA information at a four second per scan update rate and ISN data that updates at least every thirty seconds. [IRO-002-0, R7]

TVA RC ensures that SOL and IROL monitoring and derivations continue if the main monitoring system is unavailable. TVA's Reliability Coordinator has provisions for backup facilities that shall be exercised if the main monitoring system is unavailable. Communication facilities at the ROC and the back-up control facility (System Operations Center) have built in redundancy and independence from each other. [IRO-002-, R8]

Documented Procedures include: ESO-CS-SPP-12.870 Continuity of Operations (COOP); ESO-CS-SPP-12.871 Disaster Recovery; ESO-IA-SOP-10.402 Loss of SCADA and/or EMS; ESO-BA-SOP-10.313 Backup SOC (BOC) Activation; ESO-BA-SOP-10.316 Backup Network Operations Center (NOC) Activation; ESO-BA-SOP-10.317 Backup Reliability Center (BRC) Activation; TPS-SPP-14.001 ROC Facility Access Control; TPS-SPP-14.001 SOC Facility Access Control; TPS-SPP-14.003 SOC Emergency Evacuation Procedure; TPS-SPP-14.004 ROC Emergency Evacuation Procedure; TPS-SPP-18.001 SOC Fire Prevention and Response; TPS-SPP-18.002 ROC Fire Prevention and Response; ESO-VP-SDP-18.003 Rev. 0000Self-Contained Breathing Apparatus - Inspection and Use; ESO-VP-SPP-14.001 System Operations Support (SOS) Emergency Evacuation Procedure; TPS-SPP-14.0 TPS Emergency Preparedness and Response Program

TVA RC controls its Reliability Coordinator analysis tools, including approvals for planned maintenance. TVA's Reliability Coordinator has procedures in place to mitigate the effects of analysis tool outages. [IRO-002-0, R9]

Documented Procedures include: ESO-CS-SPP-12.800 Operations and Configuration Management; ESO-CS-SPP-12.810 Change Management; ESO-CS-SPP-12.821 SCADA/EMS Change Management

I. Facility (Continued)

TVA RC and Members have adequate and reliable telecommunications facilities for the exchange of Interconnection and operating information: [COM-001-0, R1]

- Internally. [COM-001-0, R1.1]
- Between TVA RC and Members. [COM-001-0, R1.2]
- With other Reliability Coordinators, Transmission Operators, and Balancing Authorities as necessary to maintain reliability. [COM-001-0, R1.3]
- Where applicable, these facilities are redundant and diversely routed. [COM-001-0, R1.4]

TVA RC manage, alarm, test and/or actively monitor vital telecommunications facilities. Special attention is given to emergency telecommunications facilities and equipment not used for routine communications. [COM-001-0, R2]

TVA RC and Members provide a means to coordinate telecommunications among their respective areas. This coordination includes the ability to investigate and recommend solutions to telecommunications problems within the area and with other areas. [COM-001-0, R3]

TVA RC and Members use English as the language for all communications between and among operating personnel responsible for the real-time generation control and operation of the interconnected Bulk Electric System. Members may use an alternate language for internal operations. [COM-001-0, R4]

TVA RC has written operating instructions and procedures to enable continued operation of the system during the loss of telecommunications facilities. [COM-001-0, R5]

TVA RC, as a NERCNet User Organization, adheres to the requirements in Attachment 1-COM-001-0, “NERCNet Security Policy.” [COM-001-0, R6]

J. Staffing

TVA RC staff all operating positions that meet both of the following criteria with personnel that are NERC certified for the applicable functions: [Standard PER-003-0, R1]

- Positions that have the primary responsibility, either directly or through communications with others, for the real-time operation of the interconnected Bulk Electric System. [Standard PER-003-0, R1.1]

- Positions directly responsible for complying with NERC standards. [Standard PER-003-0, R1.2]

The TVA Regional Operations Center is staffed with adequately trained and NERC-certified Reliability Coordinator operators, 24 hours per day, seven days per week. [Standard PER-004-0, R1] (ESO-VP-SDP-17.003 Shift Turnover Process) (ESO-VP-SDP-17.002 Guidelines for ESO Employees Entering and Exiting Employment)

TVA RC operating personnel each complete a minimum of 40 hours per year of training and drills using realistic simulations of system emergencies, in addition to other training required to maintain qualified operating personnel. [Standard PER-004-0, R2] (ESO-CS-SPP-12.880 Training) (ESO-VP-SDP-17.001 Electric System Operations System Operator Training Process)

Reliability Coordinator operating personnel have a comprehensive understanding of the Reliability Coordinator Area and interactions with neighboring Reliability Coordinator Areas. [Standard PER-004-0, R3]

Reliability Coordinator operating personnel have an extensive understanding of the Balancing Authorities and Transmission Operators within the TVA Reliability Coordinator Area, including the operating staff, operating practices and procedures, restoration priorities and objectives, outage plans, equipment capabilities, and operational restrictions. [Standard PER-004-0, R4]

Reliability Coordinator operating personnel do place particular attention on SOLs and IROLs and inter-tie facility limits. The TVA RC ensures protocols are in place to allow Reliability Coordinator operating personnel to have the best available information at all times. [Standard PER-004-0, R5] (Authority Documents: 1.0 VP System Operator Authority & 1.02 EVP System Operator Authority)

TVA's Electric System Operations (ESO) System Operator Training Process (document ESO-VP-SDP-17.001) describes the process by which System Operations personnel are trained to perform their duties, both at entry level and in continuing training status. TVA also uses the ESO Operator Training Program Manual to establish training and documentation requirements for System Operators in the form of position specific curricula, NERC certification Guidelines, On-the-Job qualification Guides, and Technical Qualification Training Checklists. The Technical Qualification Training Checklists contain competencies for the Reliability Coordinator System Operator position and the Specialist, Analysis and Operations position. An analysis of each operator position was conducted by Subject Matter Experts (SME), Management, and training representatives to develop the checklists. These checklists provide a way to identify, track, status, and document completion of required initial training for any new System Operator.

TVA uses several means to provide initial and continuing training opportunities for System Operators. TVA Employee Technical Training and Organizational Effectiveness (ETT&OE) provides much of the corporate and non-technical courses such as Standards of Conduct, Fitness for Duty, Ethics and Employee Conducts and Disciplinary Guidelines. Information Technology (IT) Education provides training on computer based applications such as Word, Excel, Access Database, etc. ETT&OE supports the development/procurement of technical training for System Operators such as the L&K Computer Based Training series on Transmission System Operations and the SOS training for NERC certification exam preparation. Each System Operator is required to complete Eighty (80) hours of continuing training per year. Continuing training is designed to keep System Operators knowledgeable of NERC Standards, operating policies, tools and equipment, and management expectations. Drills on emergency procedures and simulated exercises are included in continuing training activities.

TVA also uses a rigorous On-the-Job training process where new hires are required to work with several different TVA NERC certified Reliability Coordinators. By rotating with different Reliability Coordinators the employee is exposed to different ideas and thought processes of those currently holding shift. Only with the input from skilled RCs who have worked with the trainee, completion of the Technical Qualification Training Checklist, and the successful completion of NERC certification, can the supervisor assess the employee's readiness to operate unsupervised. These reports are then retained for documentation.

TVA RC is independent of the merchant function. RC does not pass information or data to any wholesale merchant function or retail merchant function (either internal or external) that is not made available simultaneously to all such wholesale merchant functions. An officer of TVA signed the NERC Reliability Coordinators Standards of Conduct on October 13, 2000 and this information is posted at www.nerc.com/~filez/sc-soc/signers.html. TVA's Reliability Coordinator staff has completed training on TVA's Standards of Conduct. Refresher training on TVA's Standards of Conduct is required every year. Training records are maintained.

(TVA Document: "Tennessee Valley Authority Standards Of Conduct for Transmission Providers, August 2005.)

Appendix A

Members:

Associated Electric Cooperative, Inc. (AECI)

Big Rivers Electric Corporation (BREC)

East Kentucky Power Cooperative (EKPC)

Electric Energy, Inc. (EEI)

Tennessee Valley Authority (TVA)

Reliability Coordination Agreements

"Security Coordination Agreement" executed by four parties: AECI (10/1/01), BREC (9/17/01), EKPC (9/13/01), TVA (9/11/01)

"Reliability Coordination Agreement" executed by TVA and EEI (06/28/04)

Appendix B

ECAR Inadvertent Settlement Procedure

<u>Rational</u>

ECAR's Inadvertent Settlement (IS) procedure provides a mechanism for dealing with Inadvertent Interchange that jeopardizes the reliability of the Eastern Interconnection and would apply, initially, to control areas within ECAR. The IS Tariff applies only to inadvertent interchange transactions among ECAR parties when the frequency of the Eastern Interconnection is low. Previously, the control areas balanced inadvertent interchanges by returns-in-kind. In other words, the control area drawing power from the grid could return power to the grid, even if the market rates for power during the return period were much lower. The IS Tariff is intended to remedy this problem.

<u>TVA Reliability Coordinator System Operator Action</u>

The Inadvertent Settlement Procedure is triggered when the hourly average Eastern Interconnection Frequency has been below 59.97 Hz for two successive hours. The Inadvertent Settlement Procedure will then be in effect from the first hour of low frequency until the average Eastern Interconnection frequency recovers to 59.98 Hz.

BREC and EKPC Control Area Operators will be notified by the TVA Reliability Coordinator when the 1 hour average of Frequency is below 59.97 Hz. The message to the BREC and EKPC operators shall be:

"The ECAR Inadvertent may go into effect. Frequency is low, and the average 1 hour frequency is xx.xx Hz".

BREC and EKPC Control Area Operators will be notified by the TVA Reliability Coordinator when the 1 hour average of Frequency recovers to 59.98 Hz. The message to the BREC and EKPC operators shall be:

"The Frequency has recovered. The average 1 hour frequency is xx.xx Hz."

Appendix C

Adjacent RC Agreements

MISO, PJM, TVA Congestion Management Process. April 2005

Joint Reliability Coordination Agreement Between MISO, PJM, and TVA. April 22, 2005

VACAR, TVA – under development

Southern Company, TVA – under development

Entergy, TVA – under development

Southwest Power Pool, TVA – under development

PRIMARY RESPONSIBILITIES AND SUPPORT FUNCTIONS FOR OPERATING AND OVERSEEING TRANSMISSION OWNER'S TRANSMISSION SYSTEM UNDER THE ITO/RELIABILITY COORDINATOR MODEL[1]

RELIABILITY COORDINATOR

A. Primary Responsibilities

- The Reliability Coordinator shall enforce operational reliability requirements as the NERC-certified Reliability Coordinator.

- The Reliability Coordinator shall implement applicable NERC and regional reliability criteria initiatives, such as maintaining a connection to NERC's Interregional Security Network ("ISN"), day-ahead load-flow analysis, transmission loading relief procedures, and information exchange.

- The Reliability Coordinator shall develop and coordinate with the Reliability Coordination Advisory Committee new operating procedures and guidelines and revisions to existing operating procedures and guidelines under this Agreement.

- The Reliability Coordinator shall develop and maintain system models and tools needed to perform analysis needed to develop operational plans.

- The Reliability Coordinator shall coordinate with neighboring Reliability Coordinators and other operating entities as appropriate to ensure regional reliability.

- The Reliability Coordinator shall coordinate transmission loading relief and voltage correction actions with Transmission Owner and with other Reliability Coordinators.

- The Reliability Coordinator shall identify Coordinated Flowgates and determination of flowgates requiring Reciprocal Coordination (twice annually).

- The Reliability Coordinator shall compile reservation set based on Freeze Date; compile designated resources based on Freeze Date; calculate Historic Firm Flow Values and Ratios for all coordinated flowgates on both Transmission Owner's system and adjoining systems (Bi-annual).

- The Reliability Coordinator shall develop Reciprocal Coordination Agreements that establish how each Operating Entity will consider its own Flowgate or constraint usage as well as the usage of other Operating Entities when it determines the amount of Flowgate or constraint capacity remaining. This process will include both operating horizon determination as well as forward looking capacity allocation.

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[1] This list of primary responsibilities and support functions is designed to compliment Attachment L of the OATT and does not replace or negate any provision contained therein.

- The Reliability Coordinator shall implement AFC Process -- determine AFC attribute requirements; obtain NNL Impact Data; implement Allocation Calculation Process; implement ASTFC Process; implement AFC Calculation Process; implement CMP business rules for AFC vs. ASTFC.

- The Reliability Coordinator shall provide the Transmission Owner and ITO with data necessary to analyze requests for new Transmission service.

- The Reliability Coordinator shall monitor, analyze, and coordinate the reliability of the Transmission Owner's facilities and interfaces with other Balancing Authorities, Transmission Operators, and other Reliability Coordinators.

- The Reliability Coordinator shall ensure a long-term (one year and beyond) plan is available for adequate resources and transmission within the Area; integrate and assess the plans from the Transmission Planners and Resource Planners within the Reliability Area to ensure those plans meet the reliability standards; and coordinate the development of recommended solutions to plans that do not meet those standards.

- The Reliability Coordinator shall integrate transmission and resource (demand and capacity) system models from the Relaibility Area operating entities to evaluate transmission system performance and resource adequacy.

- The Reliability Coordinator shall apply methodologies and tools to assess and analyze the transmission systems expansion plans and the resource adequacy plans.

- The Reliability Coordinator shall collect all information and data required for modeling and evaluation purposes.

- The Reliability Coordinator shall monitor all reliability-related parameters within the Reliability Authority Area, including generation dispatch and transmission maintenance plans and perform analyses of planned transmission and generation outages and the coordination of such outages with NERC, the ITO, the Transmission Owner, and other Reliability Coordinators.

- The Reliability Coordinator shall direct revisions to transmission maintenance plans as required and as permitted by agreements.

- The Reliability Coordinator shall request revisions to generation maintenance plans as required and as permitted by agreements.

- The Reliability Coordinator shall develop Interconnection Reliability Operating Limits (to protect from instability and cascading outages).

- The Reliability Coordinator shall perform the reliability analysis (actual and contingency) for the Reliability Authority Area.

- The Reliability Coordinator shall approve or deny bilateral schedules from the reliability perspective.

- The Reliability Coordinator shall assist in the determination of Interconnected Operations Services requirements for balancing generation and load, and transmission reliability (*e.g.*, reactive requirements, location of operating reserves).

- The Reliability Coordinator shall identify, communicate, and direct actions to relieve reliability threats and limit violations in the Reliability Authority Area.

- The Reliability Coordinator shall direct implementation of emergency procedures.

- The Reliability Coordinator shall direct and coordinate System Restoration.

- The Reliability Coordinator shall perform analyses to develop an evaluation of the expected next-day transmission system operations and the overall system conditions with information provided by the Transmission Owner.

- The Reliability Coordinator shall assess, develop and document resource and transmission expansion plans by:

    - Integrating and verifying that the respective resource and transmission expansion plans for the Planning Authority Area meet reliability standards.

    - Identifying and reporting on potential transmission system and resource adequacy deficiencies, and provide alternate resource and transmission expansion plans that mitigate these deficiencies.

- The Reliability Coordinator shall approve Interchange Transactions from ramping ability perspective.

- The Reliability Coordinator shall provide telemetry of transmission system information.

- The Reliability Coordinator shall notify others of any planned transmission changes that may impact their facilities.

B. Support Functions

- The Reliability Coordinator shall review the Transmission Owner’s development and maintenance of transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.

- The Reliability Coordinator shall review the Transmission Owner’s methodologies and tools for: (i) the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans; and (ii) the analysis and development of resource adequacy plans.

- The Reliability Coordinator shall review the ITO’s plans for evaluating responses to long-term (generally one year and beyond) transmission service requests

- The Reliability Coordinator shall review the ITO’s and Transmission Owner’s evaluation of transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems.

- The Reliability Coordinator shall review the ITO’s analyses and reports as required on the long-term resource and transmission plans for the Planning Authority Area.

- The Reliability Coordinator shall review the Transmission Owner’s monitoring of transmission expansion plan and resource plan implementation.

- The Reliability Coordinator shall review the Transmission Owner’s coordination of project implementation that requires transmission outages that can impact reliability and firm transactions.

- The Reliability Coordinator shall review the ITO’s evaluation of the impact of revised transmission and generator in-service dates on resource and transmission adequacy.

- The Reliability Coordinator shall review the ITO’s formulation of operational plans (generation commitment, outages, etc) for reliability assessment.

- The Reliability Coordinator shall review the Transmission Owner’s determination of the need for Interconnected Operations Services.

- The Reliability Coordinator shall review the Transmission Owner’s deployment of Interconnected Operations Services.

- The Reliability Coordinator shall review the Transmission Owner’s implementation of emergency procedures.

- The Reliability Coordinator shall review the Transmission Owner’s role in maintaining reliability of the transmission area in accordance with Reliability Standards.

- The Reliability Coordinator shall review the Transmission Owner’s maintenance schedules (dates and times).

- The Reliability Coordinator shall review the Transmission Owner’s defined voltage profiles.

- The Reliability Coordinator shall review the Transmission Owner’s definitions of operating limits, development of contingency plans, and oversight of operations of the transmission facilities.

- The Reliability Coordinator shall review the Transmission Owner's development of a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a portion of the Planning Authority Area.

- The Reliability Coordinator shall review the Transmission Owner's maintenance of transmission system models (steady-state, dynamics, and short circuit) and application of appropriate tools for the development of transmission plans.

- The Reliability Coordinator shall review the Transmission Owner's development of transmission plans to ensure that such plans are within defined voltage and stability limits and within appropriate facility thermal ratings.

- The Reliability Coordinator shall review the Transmission Owner's definitions of system protection and control needs and requirements, including special protection systems (remedial action schemes), that are needed to meet reliability standards.

- The Reliability Coordinator shall review the ITO's evaluation of and plan for transmission service and interconnection requests beyond one year.

- The Reliability Coordinator shall review the Transmission Owner's development of and report on transmission expansion plans for assessment and compliance with reliability standards.

- The Reliability Coordinator shall coordinate with the Transmission Owner to define, collect and develop information needed for planning purposes, including: (i) transmission facility characteristics and ratings; (ii) demand and energy end-use customer forecasts, capacity resources, and demand response programs; (iii) generator unit performance characteristics and capabilities; and (iv) long-term capacity purchases and sales.

- The Reliability Coordinator shall assist the ITO in reviewing and determining TTC values (generally one year and beyond) as appropriate.

- The Reliability Coordinator shall coordinate with the Transmission Owner to ensure that Transmission Owner has control over the following combinations within a Balancing Authority Area: (i) Load and Generation (an isolated system); (ii) Load and Scheduled Interchange; (iii) Generation and Scheduled Interchange; and (iv) Generation, Load, and Scheduled Interchange.

- The Reliability Coordinator shall assist the Transmission Owner in calculating Area Control Error within the Balancing Authority Area.

- The Reliability Coordinator shall assist the Transmission Owner in reviewing generation commitments, dispatch, and load forecasts.

- The Reliability Coordinator shall assist the Transmission Owner in implementing interchange schedules.

- The Reliability Coordinator shall assist the Transmission Owner in monitoring and reporting control performance and disturbance recovery.

- The Reliability Coordinator shall assist the Transmission Owner and the ITO in providing balancing and energy accounting (including hourly checkout of Interchange Schedules and Actual Interchange), and administering Inadvertent energy paybacks.

- The Reliability Coordinator shall assist the ITO in determining valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.).

- The Reliability Coordinator shall assist the ITO in verifying ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules.

- The Reliability Coordinator shall assist the ITO in collecting and disseminating Interchange Transaction approvals, changes, and denials.

- The Reliability Coordinator shall assist the ITO in authorizing implementation of Interchange Transactions.

- The Reliability Coordinator shall assist in entering Interchange Transaction information into Reliability Assessment Systems (*e.g.*, the Interchange Distribution Calculator in the Eastern Interconnection).

- The Reliability Coordinator shall assist the Transmission Owner in defining and collecting transmission information and transmission facility characteristics and ratings.

- The Reliability Coordinator shall assist the Transmission Owner in monitoring and reporting, as appropriate, on transmission expansion plan implementation.

- The Reliability Coordinator shall assist the ITO in processing transmission service requests.

- The Reliability Coordinator shall provide support to the ITO in approving or denying transmission service requests.

- The Reliability Coordinator shall provide support to the ITO in approving Interchange Transactions from a transmission service arrangement perspective.

- The Reliability Coordinator shall assist the ITO in determining and posting available transfer capability (ATC) values.

ITO

A. Primary Responsibilities

- The ITO shall evaluate plans for customer requests for transmission service.
    - The ITO shall evaluate responses to long-term (generally one year and beyond) transmission service requests.
    - The ITO shall review transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems.
- The ITO shall review and determine TTC values as appropriate.
- The ITO shall provide analyses and reports as required on the long-term resource and transmission plans for the Planning Authority Area.
- The ITO shall evaluate the impact of revised transmission and generator in-service dates on resource and transmission adequacy.
- The ITO shall formulate an operational plan (generation commitment, outages, etc) for reliability assessment.
- The ITO shall provide balancing and energy accounting (including hourly checkout of Interchange Schedules and Actual Interchange), and administer Inadvertent energy paybacks.
- The ITO shall determine valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.).
- The ITO shall verify ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules.
- The ITO shall collect and disseminate Interchange Transaction approvals, changes, and denials.
- The ITO shall authorize implementation of Interchange Transactions.
- The ITO shall maintain record of individual Interchange Transactions.
- The ITO shall evaluate and plan for transmission service and interconnection requests beyond one year.
- The ITO shall receive transmission service requests and process each request for service according to the requirements of the tariff.

- The ITO shall maintain commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (*e.g.*, OASIS).

- The ITO shall approve or deny transmission service requests.

- The ITO shall approve Interchange Transactions from transmission service arrangement perspective.

- The ITO shall determine and post available transfer capability (ATC) values.

B. Support Functions

- The ITO shall assist the Reliability Coordinator in directing revisions to transmission maintenance plans as required and as permitted by agreements.

- The ITO shall assist the Reliability Coordinator in requesting revisions to generation maintenance plans as required and as permitted by agreements.

- The ITO shall assist the Reliability Coordinator in approving or deny bilateral schedules from the reliability perspective.

- The ITO shall assist the Transmission Owner in defining, collecting, and developing demand and energy end-use customer forecasts, capacity resources, and demand response programs.

- The ITO shall assist the Transmission Owner in defining, collecting, and developing Long-term capacity purchases and sales.

- The ITO shall assist the Reliability Coordinator in assessing, developing, and documenting resource and transmission expansion plans.

    - The ITO shall assist the Reliability Coordinator in integrating and verifying that the respective plans for the Planning Authority Area meet reliability standards.

    - The ITO shall assist the Reliability Coordinator in identifying and reporting on potential transmission system and resource adequacy deficiencies, and providing alternate plans that mitigate these deficiencies.

- The ITO shall assist the Transmission Owner in monitoring transmission expansion plan and resource plan implementation.

- The ITO shall assist the Transmission Owner in coordinating project implementation that requires transmission outages that can impact reliability and firm transactions.

- The ITO shall coordinate with the Transmission Owner to ensure that Transmission Owner has control over the following combinations within a Balancing Authority Area: (i) Load and Generation (an isolated system); (ii) Load and Scheduled Interchange; (iii) Generation and Scheduled Interchange; and (iv) Generation, Load, and Scheduled Interchange.

- The ITO shall assist the Transmission Owner in calculating Area Control Error within the Balancing Authority Area.

- The ITO shall assist the Transmission Owner in reviewing generation commitments, dispatch, and load forecasts.

- The ITO shall assist the Transmission Owner in implementing interchange schedules.

- The ITO shall assist the Transmission Owner in monitoring and reporting control performance and disturbance recovery.

- The ITO shall assist in the development and review of Transmission Owner's maintenance schedules (dates and times).

- The ITO shall assist the Reliability Coordinator in notifying others of any planned transmission changes that may impact their facilities.

- The ITO shall assist the Transmission Owner in monitoring and reporting, as appropriate, on transmission expansion plan implementation.

- The ITO shall assist the Transmission Owner in allocating transmission losses (MWs or funds) among Balancing Authority Areas.

TRANSMISSION OWNER

A. Primary Responsibilities

- The Transmission Owner shall develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.

- The Transmission Owner shall maintain and apply methodologies and tools for the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans and the analysis and development of resource adequacy plans.

- The Transmission Owner shall define and collect or develop information required for planning purposes, including: (i) transmission facility characteristics and ratings; (ii) demand and energy end-use customer forecasts, capacity resources, and demand response programs; (iii) generator unit performance characteristics and capabilities; and (iv) long-term capacity purchases and sales.

- The Transmission Owner shall review transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems.

- The Transmission Owner shall monitor transmission expansion plan and resource plan implementation.

- The Transmission Owner shall coordinate project implementation that requires transmission outages that can impact reliability and firm transactions.

- The Transmission Owner must have control the following combinations within a Balancing Authority Area: (i) load and generation (an isolated system); (ii) load and Scheduled Interchange; (iii) generation and Scheduled Interchange; and (iv) generation, load, and Scheduled Interchange.

- The Transmission Owner shall calculate Area Control Error within the Balancing Authority Area.

- The Transmission Owner shall review generation commitments, dispatch, and load forecasts.

- The Transmission Owner shall implement interchange schedules by entering those schedules into an energy management system.

- The Transmission Owner shall provide frequency response.

- The Transmission Owner shall monitor and report control performance and disturbance recovery.

- The Transmission Owner shall provide balancing and energy accounting (including hourly checkout of Interchange Schedules and Actual Interchange), and administer Inadvertent energy paybacks.

- The Transmission Owner shall determine needs for Interconnected Operations Services.

- The Transmission Owner shall deploy Interconnected Operations Services.

- The Transmission Owner shall implement emergency procedures.

- The Transmission Owner shall maintain reliability of the transmission area in accordance with Reliability Standards.

- The Transmission Owner shall provide detailed maintenance schedules (dates and times) to the Reliability Coordinator for review.

- The Transmission Owner shall maintain defined voltage profiles.

- The Transmission Owner shall define operating limits, develop contingency plans, and monitor operations of the transmission facilities.

- The Transmission Owner shall provide telemetry of transmission system information.

- The Transmission Owner shall develop a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a portion of the Planning Authority Area.

- The Transmission Owner shall maintain transmission system models (steady-state, dynamics, and short circuit) and apply appropriate tools for the development of transmission plans.

- The Transmission Owner shall define and collect transmission information and transmission facility characteristics and ratings.

- The Transmission Owner shall develop transmission plans within defined voltage and stability limits and within appropriate facility thermal ratings.

- The Transmission Owner shall define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability standards.

- The Transmission Owner shall develop and report, as appropriate, on its transmission expansion plan for assessment and compliance with reliability standards.

- The Transmission Owner shall monitor and report, as appropriate, on its transmission expansion plan implementation.

- The Transmission Owner shall allocate transmission losses (MWs or funds) among Balancing Authority Areas.

B. Support Functions

- The Transmission Owner shall cooperate with the Reliability Coordinator in its enforcement operational reliability requirements.

- The Transmission Owner shall cooperate with the Reliability Coordinator in its monitoring of all reliability-related parameters within the Reliability Authority Area, including generation dispatch and transmission maintenance plans.

- The Transmission Owner shall comply with the Reliability Coordinator's revisions to transmission maintenance plans as required and as permitted by agreements.

- The Transmission Owner shall consider the Reliability Coordinator's requests for revisions to generation maintenance plans as required and as permitted by agreements.

- The Transmission Owner shall assist the Reliability Coordinator in developing Interconnection Reliability Operating Limits (to protect from instability and cascading outages).

- The Transmission Owner shall assist the Reliability Coordinator in performing reliability analyses (actual and contingency) for the Reliability Authority Area.

- The Transmission Owner shall comply with the Reliability Coordinator's approval or denial of bilateral schedules from the reliability perspective.

- The Transmission Owner shall assist in determining Interconnected Operations Services requirements for balancing generation and load, and transmission reliability (*e.g.*, reactive requirements, location of operating reserves).

- The Transmission Owner shall comply with the Reliability Coordinator's directives for relieving reliability threats and limiting violations in the Reliability Authority Area.

- The Transmission Owner shall comply with the Reliability Coordinator's directives for implementing emergency procedures.

- The Transmission Owner shall comply with the Reliability Coordinator's directives regarding System Restoration.

- The Transmission Owner shall assist the ITO in its evaluation of responses to long-term (generally one year and beyond) transmission service requests.

- The Transmission Owner shall assist the ITO in its review and determination of TTC values as appropriate.

- The Transmission Owner shall assist the Reliability Coordinator in assessing, developing, and documenting resource and transmission expansion plans.

    - The Transmission Owner shall assist the Reliability Coordinator in integrating and verifying that the respective plans for the Planning Authority Area meet reliability standards.

    - The Transmission Owner shall assist the Reliability Coordinator in identifying and reporting on potential transmission system and resource adequacy deficiencies, and providing alternate plans that mitigate these deficiencies.

- The Transmission Owner shall assist the ITO in preparing analyses and reports as required on the long-term resource and transmission plans for the Planning Authority Area.

- The Transmission Owner shall assist the ITO in evaluating the impact of revised transmission and generator in-service dates on resource and transmission adequacy.

- The Transmission Owner shall assist the ITO in formulating an operational plan (generation commitment, outages, etc) for reliability assessment.

- The Transmission Owner shall assist the ITO in determining valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.).

- The Transmission Owner shall assist the ITO in verifying ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules.

- The Transmission Owner shall assist the ITO in collecting and disseminating Interchange Transaction approvals, changes, and denials.

- The Transmission Owner shall assist the ITO in authorizing implementation of Interchange Transactions.

- The Transmission Owner shall assist in entering Interchange Transaction information into Reliability Assessment Systems (*e.g.*, the Interchange Distribution Calculator in the Eastern Interconnection).

- The Transmission Owner shall assist the Reliability Coordinator in notifying others of any planned transmission changes that may impact their facilities.

- The Transmission Owner shall assist the Reliability Coordinator in evaluating and planning for transmission service and interconnection requests beyond one year.

- The Transmission Owner shall assist the ITO in processing transmission service requests.

- The Transmission Owner shall assist the ITO in maintaining a commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (*e.g.*, OASIS).

- The Transmission Owner shall assist the ITO in the process of approving or denying transmission service requests.

- The Transmission Owner shall assist the ITO in the process of approving Interchange Transactions from transmission service arrangement perspective.

- The Transmission Owner shall assist the ITO in determining and posting available transfer capability (ATC) values.

Legend: Lead Responsibility - L Review and Approval - A Coordination - C	LG&E	RC/TVA	ITO	RC/TVA Coordination With Other TOs/RCs/RRCs
Function – Operating Reliability				
Tasks				
1. Enforce operational reliability requirements	C	L		
2. Monitor all reliability-related parameters within the Reliability Authority Area, including generation dispatch and transmission maintenance plans	C	L		
3. Direct revisions to transmission maintenance plans as required and as permitted by agreements	C	L	C	Yes
4. Request revisiCns tC generatiCn maintenance plans as required and as permitted by agreements	C	L	C	Yes
5. Develop Interconnection Reliability Operating Limits (to protect from instability and cascading outages).	C	L		
6. Perform reliability analysis (actual and contingency) for the Reliability Authority Area	C	L		Yes
7. Approve or deny bilateral schedules from the reliability perspective	C	L	C	Yes
8. Assist in determining Interconnected Operations Services requirements for balancing generation and load, and transmission reliability (e.g., reactive requirements, location of operating reserves).	C	L		
9. Identify, communicate, and direct actions to relieve reliability threats and limit violations in the Reliability Authority Area	C	L		Yes
10. Direct implementation of emergency procedures	C	L		Yes
11. Direct and coordinate System Restoration	C	L		Yes
Function – Planning Reliability				
Tasks				
1. Develop and maintain transmission and resource (demand and capacity) system models to evaluate transmission system performance and resource adequacy.	L	A		Yes
2. Maintain and apply methodologies and tools for the analysis and simulation of the transmission systems in the assessment and development of transmission expansion plans and the analysis and development of resource adequacy plans.	L	A		
3. Define and collect or develop information required for planning purposes, including:				
a. Transmission facility characteristics and ratings,	L	C		Yes
b. Demand and energy end-use customer forecasts, capacity resources, and demand response programs,	L	C	C	Yes
c. Generator unit performance characteristics and capabilities, and	L	C		Yes
d. Long-term capacity purchases and sales.	L	C	C	
4. Evaluate plans for customer requests for transmission service.				
a. Evaluate responses to long-term (generally one year and beyond) transmission service requests.	C	A	L	Yes
b. Review transmission facility plans required to integrate new (end-use customer, generation, and transmission) facilities into the interconnected bulk electric systems.	L	A	L	
5. Review and determine TTC values (generally one year and beyond) as appropriate.	C	C	L	
6. Assess, develop, and document resource and transmission expansion plans.				
a. Integrate and verify that the respective plans for the Planning Authority Area meet reliability standards.	C	L	C	Yes
b. Identify and report on potential transmission system and resource adequacy deficiencies, and provide alternate plans that mitigate these deficiencies.	C	L	C	

Legend: **Lead Responsibility - L** **Review and Approval - A** **Coordination - C**	LG&E	RC/TVA	ITO	RC/TVA Coordination With Other TOs/RCs/RRCs
7. Provide analyses and reports as required on the long-term resource and transmission plans for the Planning Authority Area.	C	A	L	Yes
8. Monitor transmission expansion plan and resource plan implementation.	L	A	C	
9. Coordinate project implementation requiring transmission outages that can impact reliability and firm transactions.	L	A	C	Yes
10. Evaluate the impact of revised transmission and generator in-service dates on resource and transmission adequacy.	C	A	L	Yes
Function – Balancing				
Tasks				
1. Must have control of any of the following combinations within a Balancing Authority Area:				
a. Load and Generation (an isolated system)	L	C	C	
b. Load and Scheduled Interchange	L	C	C	
c. Generation and Scheduled Interchange	L	C	C	
d. Generation, Load, and Scheduled Interchange	L	C	C	
2. Calculate Area Control Error within the Balancing Authority Area.	L	C	C	
3. Review generation commitments, dispatch, and load forecasts.	L	C	C	Yes
4. Formulate an operational plan (generation commitment, outages, etc) for reliability assessment	C	A	L	Yes
5. Approve Interchange Transactions from ramping ability perspective		L		Yes
6. Implement interchange schedules by entering those schedules into an energy management system	L	C	C	
7. Provide frequency response	L			
8. Monitor and report control performance and disturbance recovery	L	C	C	Yes
9. Provide balancing and energy accounting (including hourly checkout of Interchange Schedules and Actual Interchange), and administer Inadvertent energy paybacks	L	C	L	
10. Determine needs for Interconnected Operations Services	L	A		Yes
11. Deploy Interconnected Operations Services.	L	A		Yes
12. Implement emergency procedures	L	A		Yes
Function – Transmission Operations				
Tasks				
1. Maintain reliability of the transmission area in accordance with Reliability Standards.	L	A		Yes
2. Provide detailed maintenance schedules (dates and times)	L	A	C	Yes
3. Maintain defined voltage profiles.	L	A		
4. Define operating limits, develop contingency plans, and monitor operations of the transmission facilities.	L	A		Yes
5. Provide telemetry of transmission system information	L	L		
Function – Interchange				
Tasks				
1. Determine valid, balanced, Interchange Schedules (validation of sources and sinks, transmission arrangements, interconnected operations services, etc.).	C	C	L	Yes
2. Verify ramping capability of the source and sink Balancing Authority Areas for requested Interchange Schedules	C	C	L	Yes
3. Collect and disseminate Interchange Transaction approvals, changes, and denials	C	C	L	Yes

Legend: Lead Responsibility - L Review and Approval - A Coordination - C	LG&E	RC/TVA	ITO	RC/TVA Coordination With Other TOs/RCs/RRCs
4. Authorize implementation of Interchange Transactions	C	C	L	Yes
5. Enter Interchange Transaction information into Reliability Assessment Systems (e.g., the Interchange Distribution Calculator in the Eastern Interconnection)	C	C	?	Yes
6. Maintain record of individual Interchange Transactions			L	
Function – Transmission Planning				
Tasks				
Develops a long-term (generally one year and beyond) plan for the reliability (adequacy) of the interconnected bulk electric transmission systems within a portion of the Planning Authority Area.	L	A		Yes
1. Maintain transmission system models (steady-state, dynamics, and short circuit) and apply appropriate tools for the development of transmission plans.	L	A		Yes
2. Define and collect transmission information and transmission facility characteristics and ratings.	L	C		Yes
3. Develop plans within defined voltage and stability limits and within appropriate facility thermal ratings.	L	A		Yes
4. Define system protection and control needs and requirements, including special protection systems (remedial action schemes), to meet reliability standards.	L	A		
5. Determine TTC values as appropriate.	C	C	L	
6. Notify others of any planned transmission changes that may impact their facilities.	C	L	C	Yes
7. Evaluate and plan for transmission service and interconnection requests beyond one year.	C	A	L	Yes
8. Develop and report, as appropriate, on its transmission expansion plan for assessment and compliance with reliability standards.	L	A		Yes
9. Monitor and report, as appropriate, on its transmission expansion plan implementation.	L	C	C	Yes
Function – Transmission Service				
Tasks				
1. Receive transmission service requests and process each request for service according to the requirements of the tariff.	C	C	L	
a. Maintain commercial interface for receiving and confirming requests for transmission service according to the requirements of the tariff (e.g., OASIS).	C		L	Yes
2. Approve or deny transmission service requests	C	C	L	Yes
3. Approve Interchange Transactions from transmission service arrangement perspective	C	C	L	Yes
4. Determine and post available transfer capability (ATC) values.	C	C	L	
5. Allocate transmission losses (MWs or funds) among Balancing Authority Areas.	L		C	

Exhibit L

Joint Reliability Coordination Agreement
Among And Between
Midwest Independent Transmission System Operator, Inc.,
PJM Interconnection, L.L.C., And
Tennessee Valley Authority

Date: April 22, 2005

TABLE OF CONTENTS

Joint Reliability Coordination Agreement Among And Between Midwest Independent Transmission System Operator, Inc., PJM Interconnection, L.L.C., And Tennessee Valley Authority

This Joint Reliability Coordination Agreement ("Agreement") dated this 22nd day of April, 2005, among and between the following parties:

Midwest Independent Transmission System Operator, Inc. ("MIDWEST ISO"), a Delaware non-stock corporation having a place of business at 701 City Center Drive, Carmel, Indiana 46032

PJM Interconnection, L.L.C. ("PJM") a Delaware limited liability company having a place of business at 955 Jefferson Avenue, Valley Forge Corporate Center, Norristown, Pennsylvania 19403

Tennessee Valley Authority ("TVA"), a corporate entity existing under the Tennessee Valley Authority Act, 16 U.S.C. §§ 831-831ee.

ARTICLE ONE RECITALS

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

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

3. TVA is a transmission provider that provides operating and reliability functions in the TVA Reliability Coordinator area, and administers Transmission Service Guidelines for open access transmission and related services on its system. TVA is not subject to regulation by the Federal Energy Regulatory Commission as a "public utility" under the Federal Power Act;

4. The Federal Energy Regulatory Commission has ordered each regional transmission organization to develop mechanisms to address inter-regional coordination;

5. On May 20, 2004, the Parties entered into a Data Exchange Agreement Among and Between Tennessee Valley Authority, the Midwest Independent Transmission System Operator, Inc., and PJM Interconnection, L.L.C., providing for exchanges of certain data and

information in furtherance of inter-regional coordination, the reliability of their systems, and in the case of the regional transmission organizations, efficient market operations;

6. In accordance with Good Utility Practice, the Parties seek to establish or confirm other arrangements and protocols in furtherance of the reliability of their systems and efficient market operations, as provided under the terms and conditions of this Agreement, and to incorporate into this Agreement the data and information exchange to which they previously agreed as revised herein;

NOW, THEREFORE, for good and valuable consideration including the Parties' mutual reliance upon the covenants contained herein, the Parties agree as follows:

ARTICLE TWO
ABBREVIATIONS, ACRONYMS, AND DEFINITIONS

2.1 Abbreviations and Acronyms.

2.1.1 "ATC" shall mean Available Transfer Capability.

2.1.2 "AFC" shall mean Available Flowgate Capability.

2.1.3 "CBM" shall mean Capacity Benefit Margin.

2.1.4 "CF" shall mean a Coordinated Flowgate.

2.1.5 "CIM" shall mean Common Information Model.

2.1.6 "CMP" shall mean the Congestion Management Process.

2.1.7 "CRTPS" shall mean the Coordinated Regional Transmission Planning Study.

2.1.8 "EFOR" shall mean Equivalent Forced Outage Rate.

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

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

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

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

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

2.1.14 "IRL" shall mean Interconnected Reliability Limit.

2.1.15 "ISN" shall have the meaning referred to in the reference to ICCP.

2.1.16 "JOA" shall mean the Joint Operating Agreement Between The Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., as it may be amended, supplemented, or restated from time to time.

2.1.17 "JPC" shall mean the Joint Planning Committee.

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

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

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

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

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

2.1.23 "OC" shall refer to the Operating Committee under this Agreement.

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

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

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

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

2.1.28 "RC" shall mean Reliability Coordinator.

2.1.29 "RCF" shall mean a Reciprocal Coordinated Flowgate.

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

2.1.31 "RTO" refers to Regional Transmission Organization as defined in FERC's Order No. 2000, or to MIDWEST ISO and/or PJM, as applicable.

2.1.32 "SCADA" refers to a supervisory control and data acquisition system.

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

2.1.34 "SOL" shall mean System Operating Limit.

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

2.1.36 "TRM" shall mean Transmission Reliability Margin.

2.1.37 "TTC" shall mean Total Transfer Capability.

2.2 **Definitions.** Any undefined, capitalized term used in this Agreement that is not defined in this Section shall have the meaning given in the preamble of this Agreement or the CMP, and if not defined in the preamble or CMP, shall have the meaning given under industry custom, and where applicable, in accordance with Good Utility Practice.

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

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

2.2.3 "Allocation" shall mean a calculated share of capability on a Reciprocal Coordinated Flowgate to be used by Reciprocal Entities when coordinating AFC, transmission sales, and dispatch of generation resources.

2.2.4 "Available Flowgate Capability" shall have the meaning stated in Section 5.1.7.1.

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

2.2.6 "Available Transfer Capability" shall mean the Total Transfer Capability less the projected loading across the interface, less TRM and CBM.

2.2.7 "Confidential Information" shall have the meaning stated in Section 15.1.

2.2.8 "Congestion Management Process" means the Congestion Management Process document attached hereto as Attachment 1 and incorporated herein, as it may be amended, revised, or restated from time to time.

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

2.2.10 "Coordinated Flowgate" shall have the meaning stated in Section 6.1.2.1.

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

2.2.12 "Coordinated Regional Transmission Planning Study" shall have the meaning stated in Section 9.3.4.

2.2.13 "Effective Date" shall have the meaning stated in Section 14.1.

2.2.14 "Firm Flow" shall mean the estimated impacts of firm Network and Point-to-Point service on a particular Coordinated Flowgate.

2.2.15 "Firm Flow Limit" shall mean the maximum value of Firm Flows an entity can have on a Coordinated Flowgate or Reciprocal Coordinated Flowgate, as applicable, as calculated under the CMP.

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

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

2.2.18 "Governmental Authority" shall mean any federal, state, regional, local, or foreign court, tribunal, government, governmental agency, military, governmental or regulatory body (including any stock exchange, automated quotation system, or self-regulatory body), or authority over the transmission and/or generation facilities of a Party or the Parties, but shall exclude TVA in its capacity as a Party under this Agreement but shall not exclude TVA in any other capacity.

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

2.2.20 "Interconnected Reliability Limit" shall mean the value (such as MW, MVAR, Amperes, Frequency, or Volts) derived from, or a subset of, the System Operating Limits, which if exceeded, could expose a widespread area of the bulk electrical system to instability, uncontrolled separation(s) or cascading outages.

2.2.21 "Joint Planning Committee" shall have the meaning referred to in Section 9.1.

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

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

2.2.24 "Network Upgrades" shall mean those facilities located beyond the point of interconnection of the generating facility to the transmission grid.

2.2.25 "Notice" shall have the meaning stated in Section 16.11.

2.2.26 "Operating Committee" shall have the meaning stated in Section 3.3.

2.2.27 "Operating Entity" shall mean an entity that operates and controls a portion of the bulk transmission system with the goal of ensuring reliable energy interchange between generators, loads, and other operating entities.

2.2.28 "Party" or "Parties" refers to each party to this Agreement or all, as applicable.

2.2.29 "Reciprocal Coordinated Flowgate" shall have the meaning stated in Section 6.1.2.2.

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

2.2.31 "Reciprocal Entity" shall mean an Operating Entity that coordinates the future-looking management of Flowgate capability in accordance with a Reciprocal Coordination Agreement.

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

2.2.33 "Region" shall mean the Control Areas and transmission facilities with respect to which a Party serves as a transmission provider or Reliability Coordinator under NERC policies and procedures.

2.2.34 "Reliability Coordinator" shall mean, with respect to a Control Area, an entity approved by NERC to be responsible for reliability for one or more Control Areas, and which has undertaken such responsibility for the applicable Control Area.

2.2.35 "SCADA Data" shall mean the electric system security data that is used to monitor the electrical state of facilities, as specified in NERC policies and procedures.

2.2.36 "Scheduled Outages" shall mean the planned unavailability of transmission and/or generation facilities dispatched by a Party, as described in Article Seven of this Agreement, and do not include forced or other unplanned outages.

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

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

2.2.39 "Total Transfer Capability" shall mean the amount of electric energy that can be transferred over applicable transmission facilities in a reliable manner, generally the applicable rating of the applicable transmission facility.

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

2.2.41 "Transmission Service Guidelines" shall mean the TVA Transmission Service Guidelines, as amended, revised, or restated from time to time.

2.2.42 "Voltage and Reactive Power Coordination Procedures" shall have the meaning given under Article Eleven.

2.3 Rules of Construction.

2.3.1 No Interpretation Against Drafter. Each Party participated in the drafting of this Agreement and each Party agrees that no rule of construction or interpretation against the drafter shall be applied to the construction or the interpretation of this Agreement.

2.3.2 Incorporation of Preamble and Recitals. The Preamble and Recitals of this Agreement are incorporated into the terms and conditions of this Agreement and made a part thereof.

2.3.3 Rules of Interpretation. Defined terms in the singular shall include the plural and vice versa, and the masculine, feminine, or neuter gender shall include all genders. Whenever the words "include," "includes," or "including" are used in this Agreement, they are not limiting and have the meaning as if followed by the words "without limitation." The word "Section" refers to the applicable section of this Agreement and, unless otherwise stated, includes all subsections thereof. The word "Article" refers to articles of this Agreement.

2.3.4 NERC Policies and Procedures. All activities under this Agreement shall be conducted in a manner that meets or exceeds the applicable NERC policies or procedures, as such policies and procedures may be revised from time to time.

2.3.5 Geographic Scope. Each Party will perform this Agreement with respect to each Control Area for which the Party serves as transmission provider, and with respect to each Control Area for which it serves as Reliability Coordinator, provided that a Party shall be required to perform this Agreement with respect to a Control Area for which it serves as Reliability Coordinator only to the extent that the applicable agreement under which it serves in that capacity permits such performance.

ARTICLE THREE
OVERVIEW, ADMINISTRATION, AND RELATIONSHIP WITH OTHER AGREEMENTS

3.1 Overview and Scope of this Agreement. Subject to Section 3.2, this Agreement provides the following:

3.1.1 Two separate arrangements for certain exchanges of information and the implementation of reliability and efficiency protocols: (a) between TVA and MIDWEST ISO; and (b) between TVA and PJM.

3.1.2 The equitable and economical management of congestion on (a) Flowgates affected by flows of TVA and either or both MIDWEST ISO or PJM, or (b) in order to encourage and facilitate wide-spread use of the congestion management procedures by Third Parties, on Flowgates affected by the flows of any Party and any Third Party that, by executing a Reciprocal Coordination Agreement, binds itself to the congestion management procedures of this Agreement.

3.1.3 Certain arrangements among all of the Parties for coordination of their systems.

3.1.4 Certain arrangements among all of the Parties for administration of this Agreement.

3.2 Relationship Between This Agreement And The Joint Operating Agreement. Notwithstanding any provision of this Agreement, this Agreement does not govern arrangements solely between MIDWEST ISO and PJM; such arrangements are governed under the Joint Operating Agreement Between The Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C. ("JOA"), as amended from time to time. No part of this Agreement shall be construed to amend or replace any part of the JOA. In the event of any conflict between this Agreement and the JOA with respect to any undertakings or agreements between MIDWEST ISO and PJM under the JOA, the JOA shall control. Nothing in this Agreement shall cause any part of the JOA to be binding upon TVA.

3.3 Establishment and Functions of Operating Committee. To administer the arrangements under this Agreement, the Parties shall establish an Operating Committee ("OC").

3.3.1 The OC shall have the following duties and responsibilities:

3.3.1.1 Determine the date(s) for implementing the various parts of this Agreement in accordance with Section 14.1;

3.3.1.2 Meet no less than once quarterly to address any issues associated with this Agreement that a Party may raise and to determine whether any changes to this Agreement, or procedures employed under this Agreement, would enhance reliability, efficiency, or economy;

3.3.1.3 Conduct additional meetings upon Notice given by any Party, provided that the Notice specifies the reason(s) for the requested meeting;

3.3.1.4 Conduct dispute resolution in accordance with Article Twelve of this Agreement;

3.3.1.5 Initiate process reviews at the request of any Party for activities undertaken in the performance of this Agreement;

3.3.1.6 In its discretion, monitor, evaluate, and collaboratively seek to improve the congestion management process under the CMP; and

3.3.1.7 In its discretion, take other actions, including the establishment of subcommittees and/or task forces, to address any issues that the OC deems necessary in the implementation of this Agreement.

3.3.2 **Operating Committee Representatives.** Upon execution of this Agreement, each Party shall designate a primary and alternate representative to the OC and shall inform the other Parties of its designated representatives by Notice. A Party may change its designated OC representatives at any time, provided that timely Notice is given to the other Parties. Each designated OC representative shall have the authority to make decisions on issues that arise during the performance of this Agreement. The costs and expenses associated with each Party's designated OC representatives shall be the responsibility of the designating Party.

3.3.3 **Limitations Upon Authority of Operating Committee.** Any decision to implement new arrangements or protocols under this Agreement that any Party determines, in its sole discretion, would enhance its costs of performance materially, must be by unanimous consent of the three Parties' OC representatives. With respect to any other matter, unanimous agreement among the three Parties' OC representatives shall not be required; however, the representatives of MIDWEST ISO and PJM shall not have the authority to impose any decision on TVA with respect to any matter without TVA's consent.

3.4 **Data Exchange Methodologies.** In implementing the data exchange requirements of the JOA and the Data Exchange Agreement, the Parties have variously developed certain methodologies for the compilation, formatting, transmitting, and integration of the data that is also the subject of this Agreement. The Parties agree to use, to the extent possible, the previously developed methodologies for exchanging the data set forth in Article Four. If the use of such a previously developed methodology is impracticable, the Parties agree to negotiate in good faith to develop a substitute methodology for that data that will minimize the cost of developing new data exchange methodologies for all Parties.

3.5 **Relationship With Data Exchange Agreement.** As of the Effective Date, this Agreement shall replace and supersede the Data Exchange Agreement Among and Between Tennessee Valley Authority, the Midwest Independent Transmission System Operator, Inc. and PJM Interconnection, L.L.C., dated on or about May 20, 2004, and such agreement shall be deemed terminated.

3.6 **Ongoing Review and Revisions.** The Parties have agreed to the terms and conditions of this Agreement as their respective systems exist and are contemplated as of the Effective Date. The Parties expect that these systems and technology applicable to those systems and to the collection and exchange of data will change from time to time throughout the term of this Agreement, including changes to the boundaries of a Party in its capacity as an RTO, changes to the boundaries of, or identities of, Control Areas for which a Party serves as Reliability Coordinator, and changes to the Control Areas included in the security constrained, bid-based economic dispatch markets administered by PJM and MIDWEST ISO. The Parties agree that the objectives of this Agreement can be fulfilled only if the Parties, from time to time, review and, as appropriate, revise the requirements stated herein in response to changes, including deleting, adding, or revising requirements and protocols. Each Party shall negotiate in good faith in response to such revisions the other Parties may propose from time to time. Nothing in this Agreement, however, shall require any Party to reach agreement with respect to any such changes, or to purchase, install, or otherwise implement new equipment, software, or devices, or functions except as required to perform this Agreement.

ARTICLE FOUR
EXCHANGE OF INFORMATION AND DATA

4.1 **Exchange of Operating Data.** The Parties will exchange the following types of data and information: (a) Real-Time and Projected Operating Data; (b) SCADA Data; (c) EMS Models; (d) Operations Planning Data; and (e) Planning Information and Models. The frequency of exchange will be as stated with respect to specific exchanges provided under this Article or, if no frequency is stated, then the frequency shall be as necessary or appropriate to support the purpose of the exchange or otherwise in accordance with Good Utility Practice. The Operating Committee will determine various commencement dates for the exchange of information hereunder. Nothing in this Agreement shall require a Party to provide or exchange information that it does not possess or cannot obtain.

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

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

Each Party shall provide the data with respect to all of its transmission customers, and as applicable, all entities that participate in the markets it administers, during the term of the Agreement.

4.1.1 Real-Time and Projected Operating Data.

4.1.1.1 The Parties shall exchange the following information:

(a) Real–time operating information:

(i) Generation status of the units in each Party's Region;
(ii) Transmission line status;
(iii) Real-time loads;
(iv) Scheduled use of reservations;
(v) TLR information, including calculation of Market Flows;
(vi) Redispatch information, including the next most economical generation block to decrement/increment; and
(vii) Real-time constraints.

(b) Projected operating information:

(i) Unit commitment/merit order;
(ii) Maintenance schedules;
(iii) Forced outage rates;
(iv) Firm purchase and sales;
(v) Independent power producer information including current operating level, projected operating levels, Scheduled Outage start and end dates;
(vi) The planned and actual operational start-up dates for any permanently added, removed, or significantly altered transmission segments; and
(vii) The planned and actual start-up testing and operational start-up dates for any permanently added, removed, or significantly altered generation units.

4.1.1.2 The Parties agree that various components of the data exchanged under Section 4.1, including data exchanged under § 4.1.1.1 (b)(iii) (forced outage rates), § 4.1.4.5(e) (equivalent forced outage rates), § 4.1.4.10 (a) (generation Scheduled Outages) , 4.1.4.10(c) (notifications of short term forced outages), and data exchanged under § 5.1.1 (18 month schedule for

Scheduled Outages), are Confidential Information and that, in addition to the protections of Confidential Information provided under Article Fifteen:

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

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

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

4.1.2 Exchange of SCADA Data. With reference to NERC Policy No. 4, Appendix 4B, "Electric System Security Data," (Control Area data exchange) and NERC Policy No. 4B, "Reliability Coordination – Operational Security Information" (Reliability Coordinator data exchange):

4.1.2.1 The Parties shall exchange requested transmission power flows, measured bus voltages, and breaker equipment statuses of their bulk transmission facilities via ICCP or ISN.

4.1.2.2 Each Party shall accommodate, as soon as practical, another Party's request for additional ICCP/ISN bulk transmission data points, but in any event, no more than one (1) week after the request has been submitted.

4.1.2.3 The Parties will comply with all governing confidentiality agreements executed by the Parties relating to ICCP/ISN data.

4.1.2.4 The Parties shall exchange SCADA data consisting of:

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

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

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

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

(e) Control Area net interchange;

(f) Control Area total load;

(g) Control Area operating reserves; and

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

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

4.1.4 Operations Planning Data. Upon the written request of a Party, a Party shall provide the information specified in this Section to the extent such information is available or can be obtained.

4.1.4.1 Flowgates. The Parties shall exchange the following information:

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

(b) Flowgates to be added on demand;

(c) List of Coordinated Flowgates and Reciprocal Coordinated Flowgates;

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

(e) Firm and non-firm AFC for all Flowgates required under Section 4.1.4.1(c) and (d).

4.1.4.2 Transmission Service Reservations. The Parties shall exchange the following information:

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

(b) List of reservations to exclude;

(c) Reservation and interchange schedules, as required to permit the accurate calculation of TTC and ATC/AFC values;

(d) Procedures and practices used to model intra-RTO reservations, reservations on external systems, and reservation netting; and

(e) List of reservations from OASIS that should not be considered in ATC/AFC calculations.

4.1.4.3 Available Flowgate Capability Data. Each Party shall meet a minimum periodicity for calculating and making available AFCs to the other Party. The minimum periodicity depends on the service being offered. Each Party shall provide the following AFC data to the other Party:

(a) Hourly for first seven (7) days posted at a minimum, once per hour;

(b) Daily for days eight (8) through thirty-one (31), posted at a minimum, once per day; and

(c) Monthly for months two (2) through eighteen (18), posted at a minimum, twice per month.

4.1.4.4 Load Forecast. The Parties shall exchange the following load forecast data and information:

(a) Hourly for next seven (7) days, daily for days eight (8) through thirty-one (31), and monthly for months two (2) through eighteen (18), submitted once a day;

(b) Identify the origin of the forecast (e.g., identity of RTO, RC, Control Area, etc.);

(c) Indicate whether this forecast includes transmission system losses, and if it does, indicate what the percent losses are;

(d) Identify non-conforming loads;

(e) Indicate how municipal entities, cooperatives, and other entity loads are treated. Indicate whether they are included in the forecast. If so, indicate the total load or net load after removing other entity generation; and

(f) Requirements under Section 5.1.6.

4.1.4.5 Generator Data. The Parties shall exchange the following generator data:

(a) Unit owner, bus location in model;

(b) Seasonal ratings, PMIN, PMAX, QMIN, QMAX;

(c) Station auxiliaries to extent gross generation has been reported;

(d) Regulated bus, target voltage and actual voltage; and

(e) EFOR.

4.1.4.6 Designated Network Resources. The Parties shall exchange the following Designated Network Resource data:

(a) Network Integration Transmission Service Specifications;

(b) Identification of generators that serve as Designated Network Resources;

(c) Indication of treatment as pseudo tie or dynamic/static schedules;

(d) Rules for sharing output between joint owners; and

(e) Transmission arrangements.

4.1.4.7 Control Area Net Interchange from Reservations and Tags. The Parties shall exchange the following data concerning Control Area net interchange from reservations and tags:

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

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

4.1.4.8 Dynamic Schedules. The Parties shall exchange the following data concerning dynamic schedules:

(a) List of dynamic schedules;

(b) Identification of the dynamic schedules are being used to move load into the Control Area or out of the Control Area;

(c) Identification of marginal generation zones; and

(d) Requirements under Section 5.1.11.

4.1.4.9 Controllable Devices. The Parties shall exchange the following controllable devices data:

(a) Phase shifters;

(b) DC lines; and

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

4.1.4.10 Generation and Transmission Scheduled and Forced Outages. The Parties shall exchange the following data concerning Scheduled Outages of generation and transmission, and forced outages:

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

(b) Scheduled Outages of transmission resources that are planned or forecast, as soon as practicable, including all data specified in Section 5.1.3; and

(c) Notification of all forced outages of both generation and transmission resources, not to exceed 30 minutes after they are identified.

4.2 Cost of Data and Information Exchange. Each Party shall bear its own cost of providing the data and information to the other Parties as required under this Article Four and otherwise under this Agreement.

ARTICLE FIVE
TTC/ATC/AFC CALCULATIONS

5.1 TTC/ATC/AFC Protocols. As of the date of this Agreement, the Parties use the NERC SDX System to exchange the planned status of all generators rated greater than 50 MW, Scheduled Outages of all interconnections and other transmission facilities, and peak load forecasts subject to NERC SDX Data Exchange Requirements. This system has the capability to house daily data for the next seven (7) days, weekly data for the next month, and monthly data for the next year. The update frequency of the NERC SDX System is once a day. Reporting of forced outages and update of information on a basis more frequent than once a day will be completed using a separate data exchange system. Use of the NERC SDX, development of a separate data exchange system, and associated commitments under this Agreement, will assure the Parties' ability to make reliable calculations efficiently.

5.1.1 Scheduled Outages of Generation Resources. Each Party shall provide the projected status of generation availability for a minimum of eighteen (18) months, or for a longer period if the information is available. The Parties will update this data no less than once daily for the full posting horizon and more often as required by system conditions. The data will include complete generation maintenance schedules and the most current available generator availability data, such that each Party is aware of each "return date" of a generator from a scheduled or forced outage. At all times, this exchange will include the status of generators rated greater than 50 MW. If the status of a particular generator of equal to or less than 50 MW is used within a Party's TTC/ATC/AFC calculation, the status of this unit shall also be supplied.

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

5.1.3 **Scheduled Outages of Transmission Resources.** Each Party will provide the projected status of Scheduled Outages of transmission facilities for a minimum of eighteen (18) months or more if available. This data shall be updated no less than once daily for the full posting horizon and more often as required by system conditions. The data will include current, accurate, and complete transmission facility maintenance schedules, including the "outage date" and "return date" of a transmission facility from a Scheduled Outage or forced outage. If the status of a particular transmission facility is critical to the determination of TTC and ATC/AFC of a Party, the status of this facility will also be provided.

5.1.4 **Transmission Interchange Schedules and Reservations Schedules.** Each Party will make available its reservation and interchange schedules, as required to permit accurate calculation of TTC and ATC/AFC values. Due to the high volume of this data, the Parties shall either post this data to a FTP site for downloading by the other Party as required by its own process and schedules, or shall request NERC to modify the IDC to allow for selected interrogation by the Parties.

5.1.5 **Reservations.**

5.1.5.1 Each Party will make available, on an FTP site, actual transmission reservation information for integration into each Party's TTC/ATC/AFC determination process.

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

5.1.5.3 Each Party shall create, maintain, and exchange a list of reservations from its OASIS that should not be considered in ATC/AFC calculations. If a

Party does not include a reservation in its own evaluation, the reservation should be excluded in the other Party's analysis.

5.1.6 Load Data. The Parties will exchange peak load data for each period (*e.g.*, daily, weekly, and monthly) in accordance with NERC policies and procedures. Since, by definition, peak load values may only apply to one (1) hour of the period, additional assumptions must be made with respect to load level when not at peak load conditions. For the next seven (7) day horizon, the Parties shall either supply hourly load forecasts, or they shall supply daily peak load forecasts with a load profile. All load forecasts will be provided on a Control Area basis by the applicable transmission provider, RTO, RC, Control Area, or other applicable entity, including total distribution forecast by zones.

5.1.7 Calculated Firm and Non-firm Available Flowgate Capability.

5.1.7.1 "Available Flowgate Capability" ("AFC") is the Available Flowgate Rating, less the projected loading, TRM, and CBM. Firm AFC is calculated with only firm transmission service reservations (or interchange schedules) in the model, including recognition of all roll-over transmission service rights. Non-firm AFC is determined with firm and non-firm reservations (or interchange schedules) modeled.

5.1.7.2 Each Party will respect each other Party's Flowgates as follows. The Parties will utilize data provided under Section 4.1.4.1(e) to facilitate determinations whether transmission service reservations or interchange schedules will impact Flowgates to extents greater than applicable (firm or non-firm) AFC and will abide by the following procedures:

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

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

5.1.8 Exchange of Available Flowgate Ratings. The Parties will exchange (seasonal, normal, and emergency) Available Flowgate Ratings as well as all limiting conditions (thermal, voltage, or stability). The Parties will update this information in a timely manner as required by changes on the transmission system; the Parties acknowledge that these ratings are currently fairly static values and do not currently require frequent updating. Voltage and stability limits need to be periodically manually updated.

5.1.9 Identification of Flowgates. Each Party shall consider in its TTC and ATC/AFC determination process all Flowgates that may initiate a TLR event. As determined in accordance with Section 3 of the CMP, Flowgates that have a response factor equal to or greater than the distribution factor cut-off must be included in the evaluating Party's model to the extent inclusion is practical.

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

5.1.10.1 Transmission configuration changes and generation additions (or retirements) are normally communicated via the NERC MMWG process. The TTC/ATC/AFC determination processes will require that, when changes occur to the transmission network, models used in the TTC/ATC/AFC calculation be updated as soon as practical. Within sixty (60) days after the Effective Date, the Parties will institute a process to ensure that all significant system changes of a neighbor are incorporated in each Party's TTC/ATC/AFC calculation model. Although this information and other detailed data are included in the MMWG cases, this data exchange mechanism will address major changes that should be included in the TTC/ATC/AFC calculation models in a more timely manner.

This type of data change will be similar to the "New Facilities" listings usually included in inter-regional reports; however, explicit modeling information will need to be supplied along with the listing. This data exchange will occur no less often than prior to each peak load season.

5.1.10.2 The Parties agree to exchange TTC/ATC/AFC calculation models of their transmission systems as soon as mechanisms can be established to facilitate this exchange.

5.1.11 Dynamic Schedule Flows. Each Party will provide the other Party with the actual amount and future projection of dynamic schedule flows. All dynamic schedule flows and tags will be submitted in accordance with NERC policy and procedures.

ARTICLE SIX
RECIPROCAL COORDINATION OF FLOWGATES

6.1 Reciprocal Coordination of Flowgates Operating Protocols.

6.1.1 Overview. This overview is background explanation and does not replace, and should not be construed to conflict with, the definitions and procedures set out in this Agreement, including the CMP. This Agreement, including the CMP it incorporates, provides procedures for management of congestion on Flowgates. Each Party shall identify certain Flowgates it administers as Coordinated Flowgates. These are Flowgates across which there are energy flows of one or more Parties, or of one or more Parties, and one or more Third Party Operating Entities, and the flows are of such magnitudes that congestion management under the CMP would enhance reliability.

Reciprocal Coordinated Flowgates are Coordinated Flowgates (and other Flowgates as the Parties may agree) that are subjected to more substantial management, including a formal allocation of Flowgate capability among Operating Entities and their agreement to respect that Allocation. Allocations are based on historical flow levels measured as of a specified "freeze date." These reciprocal coordination procedures, set forth in detail in the CMP, are intended to enhance reliability, and reduce the likelihood of TLR procedures.

In accordance with this Agreement and the CMP, the Parties will specify those CFs which also are RCFs, and the reciprocal coordination procedures of the CMP will apply to such RCFs. The Parties recognize that many Flowgates, both within and outside their respective systems, are affected not only by their own flows, but also by flows of other Operating Entities that are not parties to this Agreement. Allocations of Flowgate capability for these Flowgates can occur equitably, and system reliability can be enhanced, if congestion management includes Allocations among all affected entities. Therefore, under this Agreement, reciprocal coordination of Flowgates can include Third Party Operating Entities when the Third Parties execute a Reciprocal Coordination Agreement with one or more Parties. The CMP will apply to all Reciprocal Coordinated Flowgates the parties designate under the Reciprocal Coordination Agreement.

6.1.2 Definitions. As used in this Article and the CMP:

6.1.2.1 "Coordinated Flowgate" or "CF" shall mean a Flowgate impacted by the flows of a Party as determined by one of the four studies identified in CMP Section 3. A Coordinated Flowgate may be in the footprint of a Party or a Third Party.

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

(1) A CF that is (a) (i) within the operational control of MIDWEST ISO or PJM, or (ii) subject to the supervision of TVA as Reliability Coordinator, and (b) affected by the transmission of energy by two or all Parties; or

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

(3) A CF that is designated by agreement of all Parties as a RCF.

6.1.3 Obligations to Respect Capability Calculations Applicable to CFs and Allocations Applicable to RCFs. In order to coordinate congestion management proactively, each Party will respect each other Party's determinations of AFC/ATC and calculations of firmness (firm, non-firm, network, non-firm hourly) for real-time operations applicable to the other Party's CFs. Additionally, each Party will respect the Allocations defined by the Reciprocal Allocation Process set forth in the CMP. Due to the provisions of the Tennessee Valley Authority Act, notwithstanding any other provisions of this Agreement, TVA cannot be required to redispatch generation, to the extent that such redispatch involves the sale of energy, to MIDWEST ISO or PJM under any circumstances. Any redispatch provided by TVA shall be provided to eligible Third Parties under separate agreements.

6.1.4 Coordination Process for Reciprocal Coordinated Flowgates. The Parties will establish and finalize the process and timing for exchanging their respective ATC/AFC calculations, and Firm Flow calculations/allocations with respect to all RCFs. The process will allocate Flowgate capability on a future-looking basis, including the allocation of Firm and Non-Firm capability (Priority 7, 6, and 2) for use in both internal dispatch and sale of transmission service. The CMP sets forth the procedure for reciprocal coordination. For any controllable Flowgate, the historically determined Firm Flow on the Flowgate and any allocated rights to that Flowgate under this process are subject to the operating practices of the controllable device. The operating practices of the controllable device will be made available to each Party before a change is made. To the extent the controllable device is able to maintain the schedule across the controllable Flowgate, there are no parallel flows and a historical allocation based on parallel flows will not occur. In this instance, the use of the controllable Flowgate will be limited to entities that have arranged transmission service across the interface formed by the controllable device. To the extent the controllable device cannot maintain the schedule across the controllable Flowgate, there will be a historical allocation based on parallel flows.

6.1.5 Real-Time Operations Process. The Parties' capabilities and real time actions, and those of any Reciprocal Entities, shall be governed by and be in accordance with the CMP.

6.2 Costs Arising From Reciprocal Coordination of Flowgates. Each Party and Reciprocal Entity will bear its own costs, if any, of compliance with the CMP and this Article.

6.3 **Transmission Capacity for Reserve Sharing.** Each Party shall make transmission capacity available for reserve sharing by either redispatching its Flowgates or holding TRM for generation outages in the other Party's system. The Party responsible for making transmission capacity available for the reserve sharing obligation shall bear its own costs.

6.4 **Maintaining Current Flowgate Models.** For operations and planning purposes, each Party will maintain a detailed model of those portions of other Parties' systems with respect to which a Party is required to respect another Party's CFs, or with respect to which the Party has received Allocations. On an ongoing basis, each Party will populate its model with credible and current data.

6.5 **Combining Contract Path Capacity.** The Parties agree to the following approach to reduce or eliminate contract path capacity limits. If two or more Parties have separate contract paths to the same entity, the combined contract path capacities under all such contracts will be made available for use by all Parties to those contracts. Because this procedure is limited to combining contract path capacities that exist under contracts, it will not create, for any Party, any new contract paths, that is, paths that do not exist under a contract. Combining contract path capacity shall give no Party or Third Party any right to circumvent the restrictions set forth in the Federal Power Act, 16 U.S.C. § 824k.

6.6 **Improvements; Adoption of Superior Provisions Concerning Allocation.** The Parties will collaboratively seek to improve congestion management to enhance efficiency, reliability, cost effectiveness, and equity. If any two Parties enter into an agreement between themselves, or if a Party enters into an agreement with a Third Party, regarding an allocation process for Reciprocal Coordinated Flowgates, and that agreement contains allocation provisions that a Party reasonably deems to be more favorable to the Third Party than the Flowgate allocation provisions of Section 6 of the CMP, then, upon the request of such Party, Section 6 of the CMP shall be amended to incorporate such allocation provisions.

ARTICLE SEVEN
COORDINATION OF SCHEDULED OUTAGES

7.1 **Operating Protocols for Coordinating Scheduled Outages.** The Parties will jointly develop protocols for coordinating transmission and generation Scheduled Outages to ensure reliability. The Parties agree to the following with respect to transmission and generation Scheduled Outage coordination.

7.1.1 **Exchange of Transmission and Generation Scheduled Outage Data.** Upon a Party's request, the projected status of generation and transmission availability will be communicated among the Parties, subject to data confidentiality agreements. All available information regardless of scheduled date will be shared. The Parties shall exchange the most current information on proposed Scheduled Outage information and provide a timely response on potential impacts of proposed Scheduled Outages.

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

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

7.1.2 Evaluation and Coordination of Transmission and Generation Scheduled Outages. The Parties will utilize network applications to analyze planned critical facility maintenance to determine its effects on the reliability of the transmission system. Each Party's Scheduled Outage analysis will consider the impact of its critical Scheduled Outages on the other Party's system reliability, in addition to its own. The analysis will include, as a minimum: an evaluation of contingencies including potential real or reactive power concerns; voltage analysis; and real and reactive power reserve analysis.

On a daily basis, the operations staff of the Parties shall jointly discuss any Scheduled Outages to identify potential impacts. These discussions should include an indication of either concurrence with the Scheduled Outage or identify significant impact due to the Scheduled Outage as scheduled. No Party has the authority to cancel another Party's Scheduled Outage (except transmission facilities interconnecting the two Parties' transmission systems). However, the Parties will work together to resolve any identified Scheduled Outage conflicts. Consideration will be given to Scheduled Outage submittal times and Scheduled Outage criticality when addressing conflicts. If analysis of Scheduled Outages indicates unacceptable system conditions, the Parties will work with one another and the facility owner(s), as necessary, to provide remedial steps to be taken in advance of proposed maintenance. If an operating procedure cannot be developed, and a change to the proposed schedule is necessary based on significant impact, the Parties shall discuss the facts involved, and make every effort to effect the requested schedule change. If this change cannot be accommodated, the Party with the Scheduled Outage shall notify the impacted Party. A request to adjust a proposed Scheduled Outage date must include: identification of the facility(s) overloaded; and identify a similar time frame of more appropriate dates/times for the Scheduled Outage.

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

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

ARTICLE EIGHT
PRINCIPLES CONCERNING JOINT OPERATIONS IN EMERGENCIES

8.1 Emergency Operating Principles.

8.1.1 In the event an emergency condition is declared in accordance with a Party's published operating protocols, the Parties will coordinate respective actions to provide immediate relief until the declaring Party eliminates the declaration of emergency. The Parties will notify each other of emergency maintenance and forced outages as soon as possible after the conditions are known. The Parties will evaluate the impact of emergency and forced outages on the Parties' systems and coordinate to develop remedial steps as necessary or appropriate. If the emergency response allows for coordinating with the other Party before action must be taken, the normal procedures for action requests will be followed. The Parties will conduct joint annual emergency drills, and will ensure that all operating staff are trained and certified, if required, and will practice the joint emergency drills that include criteria for declaring an emergency, prioritizing action plans, staffing and responsibilities, and communications.

8.1.2 In furtherance of maintaining system stability, and providing prompt response to problems, the Parties agree that in situations where there is an actual IRL violation and/or the system is on the verge of imminent collapse, and when there exists an applicable emergency principles or operating guide, each Party will allow the affected Party to take immediate steps by modifying the normal procedures for action requests so that the Parties and affected operating entities can communicate and coordinate simultaneously via telephone conference call or other appropriate means. Subsequent to such departures from normal procedures, the requesting Party will prepare a lessons learned report and provide copies thereof to the other Parties and affected operating entities. The purpose of the lesson learned report is to assist in improving operations so that future operations will be more proactive; thereby, avoiding such abnormal communications/procedures.

8.1.3 The Parties will use all applicable emergency principles and operating guides. The Parties will work together and with the Control Areas with respect to which they serve as RTO or Reliability Coordinator, as applicable, to jointly develop and commit to additional emergency principles and operating guides as the need for such procedures arises.

8.1.4 TLR Level 6 may be implemented when, in the judgment of a Party, the system is in an emergency condition that is characterized by the potential, either imminently or for the next contingency, for system instability or cascading, or for equipment loading or voltages significantly beyond applicable operating limits, such that stability of the system cannot be assured, or to prevent a condition or situation that in the judgment of a Party is imminently likely to endanger life or property. In the event that either it becomes necessary for a Party to issue a TLR Level 6 for an area that is in close electrical proximity to any of the Parties' Regions, the affected Parties will either issue a TLR Level 6 or redispatch without declaring a TLR, and take action(s) in kind to address the situation that prompted the TLR. These actions may include:

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

(b) Redispatching of generation within the affected Parties; and

(c) Load shedding within the affected Parties.

8.1.5 In situations where an actual IRL violation exists, or for the next contingency would exist, and the transmission system is currently, or for the next contingency would be, on the verge of imminent collapse, and there is not an existing emergency principle or operating guide, each Party will receive, and subject to the next two sentences of this Section implement, the instruction of the affected Party, communicate the instruction to the affected entity within its own boundary, or utilize telephone conference call capabilities or other appropriate means of communication to allow simultaneous coordination/communication between the Parties and the affected entity. All occurrences of this kind may be reviewed by any or all Parties after the fact, but the instruction of the affected Party shall be implemented when issued, except a Party may delay implementation in instances where a Party concludes that the requested action will result in a more serious condition on the transmission system, or the requested action is imminently likely to endanger life or property. Financial considerations shall have no bearing on actions taken to prevent the collapse of the transmission system.

8.1.6 In a situation where an SOL violation exists within a Party's Region, or for the next contingency would exist, the Parties will work together as necessary, following Good Utility Practices, and take action in kind as required to address the situation.

8.1.7 To the extent a Party is a RC with respect to Control Areas, the Party will also coordinate in that capacity with the other Parties and, as may be provided under arrangements other than this Agreement, direct emergency action on the part of generation or transmission within such Control Areas to protect the reliability of the network. Each Party shall exercise such authority in accord with Good Utility Practice as required to resolve emergency conditions in another Party's Region of which it is aware and, in conjunction with any applicable stakeholder processes, will develop detailed emergency operating procedures.

8.1.7.1 Power System Restoration. Effective procedures for restoration of the network require coordination and communication at all levels of the Parties' organizations and with their membership. During power system restoration, the Parties will coordinate their actions with each other, as well as with other appropriate entities in order to restore the transmission system as safely and efficiently as possible. In order to enhance the effectiveness of actual restoration operations among the Parties, the Parties will conduct annual coordinated restoration drills. These drills will stress cooperation and communication so that the Parties are positioned to better assist each other mutually in an actual restoration.

8.1.7.2 Joint Voltage Stability Operating Protocol. Voltage stability or collapse problems have the potential to cause cascading outages and therefore must be closely coordinated to maintain reliable operations. The Parties will coordinate their operations in accordance with Good Utility Practice in order to maintain stable voltage profiles throughout their respective Regions. The Parties will coordinate their established daily voltage/reactive management plans. This coordination will serve to assure an adequate static and dynamic reactive supply under a credible range of system dispatch patterns across both Parties' systems and will assure the plans are complementary.

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

8.2 Costs of Compliance with Emergency Principles and Procedures. In accordance with each Party's OATT, Transmission Service Guidelines, or other agreements, each Party is to bear its own costs of compliance with this Article. Purchases of emergency energy by PJM under this Article in order to address the flow of MIDWEST ISO, or purchases of emergency energy by MIDWEST ISO under this Article in order to address the flow of PJM, shall occur in accordance with the JOA and not this Agreement. Nothing in this Agreement shall require a Party to purchase emergency energy if the Party cannot recover the costs under an OATT, its Transmission Service Guidelines, or other agreement or lawful arrangement. Notwithstanding any other provisions of this Agreement, MIDWEST ISO and PJM acknowledge that TVA cannot sell energy, including emergency energy, to any entity that is not an authorized purchaser under the Tennessee Valley Authority Act. Any such sale shall be provided to eligible Third Parties under separate agreements.

ARTICLE NINE
COORDINATED REGIONAL TRANSMISSION EXPANSION PLANNING

9.1 Joint Planning Committee. The OC shall form, as a subcommittee of the OC, a "Joint Planning Committee" ("JPC"). The JPC shall be, comprised of representatives of the Parties' respective staffs in numbers and functions to be identified from time to time. The JPC shall have a Chairman. The Chairman shall be responsible for: the scheduling of meetings; the preparation of agendas for meetings; the production of minutes of meetings; and for chairing JPC meetings. The Chairman shall serve a one-year calendar term, except that the term of the first Chairman shall commence on the Effective Date and terminate at the end of the calendar year of the Effective Date. The OC shall designate the first Chairman. Thereafter, the right to designate the Chairman shall rotate from Party to Party in the following order: MIDWEST ISO, PJM, and TVA. The JPC shall coordinate planning of the Parties' respective systems under this Agreement, including the following:

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

9.1.2 Conduct, on a regular basis, a Coordinated Regional Transmission Planning Study (CRTPS), as set forth in Section 9.3.4.

9.1.3 Coordinate planning activities under this Article Nine, including the exchange of data under this Article and developing necessary report and study protocols.

9.1.4 Maintain an Internet site and e-mail or other electronic lists for the communication of information related to the coordinated planning process.

9.1.5 Meet at least semi-annually to review and coordinate transmission planning activities.

9.1.6 Establish working groups as necessary to address specific issues, such as the review and development of the regional plans of each Party and localized seams issues.

9.1.7 Establish a schedule for the rotation of responsibility for data management, coordination of analysis activities, report preparation, and other activities.

9.1.8 Schedule and oversee an annual meeting of the Parties' system operations, market operations, and system planning personnel (such personnel as the Parties may designate for the meeting), to review issues associated with these functions that may impact long range planning and the coordination of planning between and among the systems.

9.2 Data and Information Exchange. Each Party shall provide the other Parties with the following data and information. Unless otherwise indicated, such data and information shall be provided annually.

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

9.2.2 Fully detailed planning models (up to the next ten (10) years) (transmission assessment plans) on an annual basis and monthly updates that reflect system enhancement changes or other changes, as they occur.

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

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

9.2.5 Transmission system maps for the Party's bulk transmission system and lower voltage transmission system maps that are relevant to the coordination of planning between or among the systems.

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

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

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

9.2.9 Quarterly, the status of all interconnection requests that have been identified.

9.2.10 Information regarding long-term firm transmission services on all interfaces relevant to the coordination of planning between or among the systems.

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

9.3 **Coordinated System Planning.** The Parties shall engage in coordinated system planning to identify expansions or enhancements to transmission system capability that may be needed to maintain reliability and/or improve operational performance. The Parties will coordinate any and all studies required to assure the reliable, efficient, and effective operation of the transmission systems. The Parties will conduct such coordinated planning as set forth below

9.3.1 **Single Party Planning.** Each Party shall engage in such transmission planning activities, including expansion plans, system impact studies, and generator interconnection studies, as necessary to fulfill its obligations under its applicable OATT, Transmission Service Guidelines, or as it otherwise shall deem appropriate. Such planning shall conform to applicable reliability requirements of NERC, applicable regional reliability councils, and any successor organizations thereto. Such planning shall also conform to any and all applicable requirements of Federal or State regulatory authorities. Each Party agrees to prepare a regional transmission planning report that documents the procedures, methodologies, and business rules utilized in preparing and completing the report. Each Party shall share its annual transmission planning reports and assessments with the other Parties, as well as any information that arises in the performance of such single party planning activities as is necessary or appropriate for effective coordination between the Parties on an ongoing basis.

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

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

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

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

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

9.3.2.5 The direct connect system will collect from the interconnection customer the costs incurred by the potentially impacted Party associated with the performance of such studies and forward collected amounts, no later than thirty (30) days after receipt thereof, to the potentially impacted Party. Upon the reasonable request of a Party, the Parties will make their books and records available to the requesting Party pertaining to such requests for collection and receipt of collected amounts.

9.3.2.6 The direct connect system will identify any transmission infrastructure improvements required as a result of the proposed interconnection.

9.3.2.7 Construction and cost responsibility associated with any transmission infrastructure improvements required as a result of the proposed interconnection shall be accomplished under the terms of the applicable OATT, Transmission Service Guidelines, controlling agreements, and consistent with applicable Federal or State regulatory policy and applicable law.

9.3.2.8 Thermal and reactive impacts associated with circulation and other phenomena that result from interconnection and impact the systems of both Parties will be evaluated in the evaluation of specific requests associated with delivery service.

9.3.2.9 Each Party will maintain a separate interconnection queue. The JPC will maintain a composite listing of interconnection requests for all interconnection projects that have been identified as potentially impacting the systems of any Party. The JPC will post this listing on the Internet site maintained for the communication of information related to the coordinated system planning process.

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

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

9.3.3.2 Upon the posting to the OASIS of a request for service, the Party receiving the request will determine whether another Party is potentially impacted. If another Party is potentially impacted, the Party receiving the request will notify such Party and convey the information provided in the posting.

9.3.3.3 If the potentially impacted Party determines that its system may be materially impacted by granting the service, such Party will contact the Party receiving the request and request participation in the applicable studies. The Parties will coordinate with respect to the nature of studies to be performed to test the impacts of the requested service on the potentially impacted Party. The Parties will strive to minimize the costs associated with the coordinated study process. The JPC will develop screening procedures to assist in the identification of service requests that may impact systems of the Parties other than the Party receiving the request.

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

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

9.3.3.6 The Party receiving the request will collect from the transmission service customer, and forward to the potentially impacted Party, the costs incurred by the potentially impacted Parties associated with the performance of such studies.

9.3.3.7 The Party receiving the request will identify any transmission infrastructure improvements required as a result of the transmission service request.

9.3.3.8 Construction and cost responsibility associated with any transmission infrastructure improvements required as a result of the transmission service request shall be accomplished under the terms of the applicable OATT, Transmission Service Guidelines, controlling agreements, and consistent with applicable Federal or State regulatory policy and applicable law.

9.3.4 **Coordinated Transmission Planning.** Each Party agrees to assist in the conduct of the CRTPS as follows:

9.3.4.1 Every three years, the Parties shall conduct a CRTPS. Sensitivity analyses will be performed, as required, during the off years based on a review by the JPC of discrete reliability problems or operability issues that arise due to changing system conditions.

9.3.4.2 The CRTPS shall identify all reliability and expansion issues, and shall propose potential resolutions to be considered by the Parties.

9.3.4.3 Nothing in this Agreement shall obligate any Party in any way to construct, finance, operate, or otherwise support any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS. Any decision to proceed with any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS shall be set forth in a separate agreement executed by the Parties.

9.3.4.4 Nothing in this Agreement shall give any Party any rights to financial compensation due to the impact of another Party's transmission plans, including but not limited to its decisions whether or not to construct any transmission infrastructure improvements or other transmission-related projects identified in the CRTPS

9.3.4.5 Each Party will be responsible for providing the technical support required to complete the analysis for the CRTPS.

9.3.4.6 The JPC will develop the scope and procedure for the CRTPS. The scope of the CRTPS will include evaluations of the transmission systems against reliability criteria, operational performance criteria, and economic performance criteria applicable to each Party.

9.3.4.7 The Parties will use planning models that are developed in accordance with the procedures to be established by the JPC. Exchange of power flow models will be in a format that is acceptable to all Parties.

9.3.4.8 The CRTPS will initially evaluate the reliability of the combined transmission systems.

9.3.4.9 The performance of the combined transmission systems will be tested against agreed upon operational and economic criteria, where applicable, using the updated baseline model.

9.3.4.10 Economic criteria applicable to each Party will be developed by that Party.

9.3.5 **Review and Approval Processes.** To the extent applicable, each Party shall conduct the necessary stakeholder review and approval process associated with transmission system planning, as required by its OATT or Transmission Service Guidelines, governing agreements, and/or applicable Federal or State regulatory requirements.

ARTICLE TEN
JOINT CHECKOUT PROCEDURES

10.1 Scheduling Checkout Protocols.

10.1.1 Scheduling Protocols. Each Party will leverage technology to perform electronic approvals of schedules, and to perform electronic checkouts, in lieu of telephone calls. The Parties will follow the following scheduling protocols:

10.1.1.1 Each Party, acting as the scheduling agent for its respective Control Areas, will conduct all checkouts with first tier Control Areas. A first tier Control Area is any Control Area that is directly connected to any Party's members' Control Area or any Control Area operated by an independent transmission company.

10.1.1.2 The Parties will require all schedules to be tagged in accord with the NERC tagging standard. For reserve sharing and other emergency schedules that are not tagged, the Parties will enter manual schedules after the fact into their respective scheduling systems to facilitate checkout between the Parties.

10.1.1.3 When there is a scheduling conflict, the Parties will work in unison to modify the schedule as soon as practical. If there is a scheduling conflict that is identified before the schedule has started, then both Parties will make the correction in real-time and not wait until the quarter hour. If the schedule has already started and one Party identifies an error, then the Parties will make the correction at the earliest quarter hour increment. If a scheduling conflict cannot be resolved between the

Parties (but the source and sink have agreed to a MW value), then the Parties will both adjust their numbers to that same MW value. If source and sink are unable to agree to a MW value, then the previously tagged value will stand for both Parties.

10.1.1.4 For entities that do not use the respective Parties' electronic scheduling interfaces, the Parties will contact the non-member first-tier entities by telephone to perform checkouts.

10.1.1.5 The Parties will perform the following types of checkouts:

(a) Pre-schedule (Day-Ahead), daily between 1600 and 2000 hours.

(b) Hourly Before the Fact (Real-Time):

(i) Hourly before the fact checkout includes the verification of import and export totals, and is not limited to net scheduled interchange for Control Areas with the ability to determine such net scheduled interchange. At a future time, the Parties may checkout individual schedules;

(ii) Hourly checkout is performed starting at the half hour and ending at the ramp hour;

(iii) Intra-hour checkout/schedule confirmation will occur as required due to intra-hour scheduled changes.

(c) After the fact (day end) daily starting at 0100 hours.

(d) After the fact (monthly) on a daily month to date basis (usually via email), starting on the first business day of the following month and ending by the tenth (10th) business day of that month.

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

ARTICLE ELEVEN
VOLTAGE CONTROL AND REACTIVE POWER COORDINATION

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

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

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

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

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

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

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

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

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

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

11.2.7 At least once each calendar quarter, the Parties will exchange voltage schedules and meet and confer to identify system conditions that could impact the schedules and determine adjustments to the schedules, consistent with reliability.

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

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

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

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

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

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

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

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

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

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

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

11.2.10 Voltage/Reactive Transfer Limits.

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

(a) At 95% of Interface Limit:

(i) A Party, which observes the reading, shall contact the other Parties to discuss whether further analysis is required.

(ii) The Party, owning the applicable Flowgate, will notify other Reliability Coordinators via the Reliability Coordinator Information System ("RCIS").

(iii) The Parties will conduct a conference call with the affected Control Areas to discuss reactive outputs and/or capabilities.

(iv) The applicable Party will take appropriate actions, which may include redispatching generation and directing schedule curtailments.

(b) Exceeding Interface Limit:

(i) The Party owning the applicable Flowgate will declare an emergency and inform other Reliability Coordinators of the emergency.

(ii) The applicable Party will take immediate action, which may include generation redispatch, ordering immediate schedule curtailments, and if required, load shedding.

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

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

ARTICLE TWELVE
DISPUTE RESOLUTION PROCEDURES

12.1 Dispute Resolution Procedures. The Parties shall attempt in good faith to achieve consensus with respect to all matters arising under this Agreement and to use reasonable efforts through good faith discussion and negotiation to avoid and resolve disputes that could delay or impede a Party from receiving the benefits of this Agreement. These dispute resolution procedures apply to any dispute that arises from a Party's performance of, or failure to perform, this Agreement and which the applicable Parties are unable to resolve prior to invocation of these procedures. In the event a dispute arises solely between MIDWEST ISO and PJM, and that dispute also arises under the JOA, this Article shall not apply to the dispute and the dispute resolution provisions of the JOA shall apply.

12.1.1 Step One. In the event a dispute arises, a Party shall give Notice of the dispute to the other Party or Parties to the dispute. Within ten (10) days of such Notice, the OC shall meet and the Parties will attempt to resolve the Dispute by reasonable efforts through good faith discussion and negotiation. In addition to a Party's OC representative, a Party shall also be permitted to bring no more than two (2) additional individuals to OC meetings held under this Step One as subject matter experts; however, all such participants must be employees of the Party they represent. In addition, each Party may bring no more than two (2) attorneys.

12.1.2 Step Two. In the event the OC is unable to resolve the dispute under Step One within twenty (20) days of the giving of Notice as provided under Section 12.1.1, and only in such event, a Party shall be entitled to invoke Step Two. A Party may invoke Step Two by giving Notice thereof to the OC no later than thirty (30) days after the meeting of the OC under Step One. **IF A PARTY DOES NOT INVOKE STEP TWO WITHIN SUCH THIRTY (30)-DAY PERIOD, IT WILL BE DEEMED TO HAVE WAIVED ITS RIGHTS WITH RESPECT TO THE DISPUTE, AND SHALL BE PRECLUDED FROM PURSUING ITS RIGHTS OR DEFENDING UNDER STEP TWO OR STEP THREE.** In the event a Party invokes Step Two, the OC shall, in writing, and no later than five (5) days after receipt of the Notice, refer the dispute in writing for consideration to the officers of highest authority of the applicable Parties. Such officers shall meet in person no later than fourteen (14) days after such referral, and shall make a good faith effort to resolve the dispute. The Parties shall exchange written position papers concerning the dispute no later than forty-eight (48) hours in advance of such meeting. In the event the Parties fail to resolve the dispute under Step Two, any one of the disputing Parties shall be entitled to invoke Step Three.

12.1.3 Step Three. After completion of Steps One and Two, any Party to the dispute shall have the right to file, with respect to the dispute, an action only in the United States District Court for the District of Columbia, except as provided below, and each Party submits itself to the personal jurisdiction of such Court. The Parties agree that in any such action, each Party to the dispute will stipulate to have a United States Magistrate Judge conduct any and all proceedings in the litigation in accordance with 28 U.S.C. § 636(c), and Fed. R. Civ. P. 73, and shall waive any right to a trial of the dispute by jury. The decision of the Magistrate Judge shall be final and binding on the disputing Parties, and not subject to appeal, and any Party to the dispute may seek to enforce the decision, and any resulting order or judgment by judicial proceedings. In the event the United States District Court dismisses the action for lack of subject matter jurisdiction, and notwithstanding the foregoing, a Party may file an action in any court with jurisdiction in order to obtain a resolution of the dispute, and any right of any Party to the dispute to trial of the action by jury shall be waived.

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

ARTICLE THIRTEEN
RETAINED RIGHTS OF PARTIES

13.1 Parties Entitled to Act Separately. This Agreement does not create or establish, and shall not be construed to create or establish, any partnership or joint venture between or among any of the Parties. This Agreement establishes terms and conditions solely of a contractual relationship, among independent entities, to facilitate the achievement of the joint objectives described in the Agreement. The contractual relationship established hereunder implies no duties or obligations among the Parties except as specified expressly herein. All obligations hereunder shall be subject to, and performed in a manner that complies with each Party's internal requirements; provided, however, this sentence shall not limit any payment obligation, or indemnity obligation under Section 16.3.

ARTICLE FOURTEEN
EFFECTIVE DATE, IMPLEMENTATION, TERM AND TERMINATION

14.1 Effective Date; Implementation. This Agreement shall become effective on the date it is executed by all Parties ("Effective Date"). All data exchange provided hereunder that, prior to the Effective Date, was occurring under the Data Exchange Agreement Among and Between Tennessee Valley Authority, the Midwest Independent Transmission System Operator, Inc., and PJM Interconnection, L.L.C., dated on or about May 20, 2004, shall continue without interruption. Commencing with the Effective Date, the Parties shall commence and continue efforts to implement other provisions of this Agreement on dates determined by the OC, which dates shall be the earliest dates reasonably feasible for all Parties but none of which are expected to be earlier than June 1, 2005.

14.2 Term. This Agreement shall continue in full force and effect for a term of ten (10) years, and shall continue year to year thereafter, unless terminated earlier in accordance with the provisions of this Agreement.

14.3 Right of a Party to Terminate.

14.3.1 TVA may terminate this Agreement with respect to MIDWEST ISO, PJM, or both, at any time upon not less than twelve (12) months' Notice to both MIDWEST ISO and PJM.

14.3.2 MIDWEST ISO may terminate this Agreement with respect to both PJM and TVA at any time upon not less than twelve (12) months' Notice to both PJM and TVA.

14.3.3 PJM may terminate this Agreement with respect to both MIDWEST ISO and TVA at any time upon not less than twelve (12) months' Notice to both MIDWEST ISO and TVA.

14.3.4 Any Party may terminate this Agreement in accordance with Section 14.4, 14.5, or 14.6.

14.4. Termination Due to Regulatory Action. In the event that FERC, or any person, takes any action to subject TVA or TVA's activities under this Agreement to FERC's jurisdiction under the Federal Power Act, any Party may terminate this Agreement upon thirty (30) days' Notice.

14.5 Termination Due To FERC Modification. The Parties subject to jurisdiction of the FERC under the Federal Power Act have concluded that this Agreement need not be filed with FERC under the Federal Power Act and its implementing regulations. To any extent that FERC, any other administrative or judicial body, or any other person requires this Agreement to be filed with FERC for acceptance and approval, any Party may terminate this Agreement upon thirty (30) days' Notice if FERC makes any modifications to the provisions of this Agreement.

14.6 Change in NERC. This Agreement is premised on the existence of NERC, and the applicability of NERC definitions, policies, and procedures. To the extent that NERC ceases to exist in its current form, and/or is replaced with an entity with authority for reliability over the transmission systems of the Parties, the Parties shall promptly meet to determine whether to revise this Agreement to reflect the new reliability entity and the Parties' obligations in light of the authority of the new reliability entity or to terminate this Agreement.

14.7 Survival. The applicable provisions of this Agreement shall continue in effect after any termination of this Agreement to provide for adjustments and payments under Article Twelve, dispute resolution, determination and enforcement of liability, and indemnification, arising from acts or events that occurred during the period this Agreement was in effect.

14.8 Post-Termination Cooperation. Following any termination of this Agreement, all Parties shall thereafter cooperate fully and work diligently in good faith to achieve an orderly resolution of all matters resulting from such termination.

ARTICLE FIFTEEN
CONFIDENTIAL INFORMATION

15.1 Definition. The term "Confidential Information" shall mean: (a) all data and information, whether furnished before or after the execution of this Agreement, whether oral, written, or recorded/electronic, and regardless of the manner in which it is furnished, that is marked "Confidential" or "Proprietary" or which under all of the circumstances should be treated as confidential or proprietary; (b) any data or information deemed confidential under some other form of confidentiality agreement or tariff provided to a Party by a generator; (c) all reports, summaries, compilations, analyses, notes, or any other data or information of a Party hereto which are based on, contain, or reflect any Confidential Information; (d) applicable material deemed Confidential Information pursuant to the PJM Data Confidentiality Regional Stakeholder Group; and (e) any data and information which, if disclosed by a transmission function employee of a utility regulated by the FERC to a market function employee of the same utility system, other than by public posting, would violate the FERC's Standards of Conduct set forth in 18 C.F.R. §§ 37.1-37.8 and the Parties' Standards of Conduct on file with the FERC for PJM and MIDWEST ISO and TVA's Standard of Conduct. The Parties agree that Confidential Information constitutes commercially sensitive, and proprietary trade secret information.

15.2 **Protection.** During the course of the Parties' performance under this Agreement, a Party may receive or become exposed to Confidential Information. Except as set forth herein, the Parties agree to keep in confidence, and not to copy, disclose, or distribute any Confidential Information or any part thereof, without the prior written permission of the issuing Party. In addition, each Party shall ensure that its employees, its agents, its subcontractors, and its subcontractors' employees, and agents to whom Confidential Information is given or exposed, agree to be bound by the terms and conditions contained herein. Each Party shall be liable for any breach of this Article by its employees, its agents, its subcontractors, and its subcontractors' employees and agents.

15.3 **Scope.** This obligation of confidentiality shall not extend to data and information that, at no fault of a recipient Party, is or was: (a) in the public domain or generally available or known to the public; (b) disclosed to a recipient by a non-Party who had a legal right to do so; (c) independently developed by a Party or known to such Party prior to its disclosure hereunder; and (d) which is required to be disclosed by subpoena, law, or other directive of a Governmental Authority.

15.4 **Standard of Care.** Each Party shall protect Confidential Information from disclosure, dissemination, or publication. Regardless of whether a Party is subject to the jurisdiction of the FERC under the Federal Power Act, and regardless of whether a Party is a RTO, each Party agrees to restrict access to all Confidential Information to only those persons authorized to view such information: (a) by the FERC's Standards of Conduct, 18 C.F.R. §§ 37.1-37.8 or, if more restrictive, (b) by such Party's board resolutions, tariff provisions, or other internal policies governing access to, and the sharing of, energy market or transmission system information.

15.5 **Required Disclosure.** If a Governmental Authority requests or requires a Party to disclose any Confidential Information, such Party shall provide the supplying Party with prompt Notice of such request or requirement so that the supplying Party may seek an appropriate protective order or other appropriate remedy or waive compliance with the provisions of this Agreement. Notwithstanding the absence of a protective order or a waiver, a Party shall disclose only such Confidential Information, which it is legally required to disclose. Each Party shall use reasonable efforts to obtain reliable assurances that confidential treatment will be accorded to Confidential Information required to be disclosed.

In response to any Freedom of Information Act (FOIA) request for information received from or relating to a Party which has been designated Confidential Information, TVA shall evaluate the request and determine the applicability of any FOIA exemptions. TVA shall consult with the affected Party regarding the applicability of the FOIA exemptions, including 5 U.S.C. § 552. Pursuant to its responsibilities under the FOIA, TVA must make the final determination regarding whether the information requested is legally exempt from disclosure under the FOIA, and shall notify the affected Party in advance of the release of any Confidential Information as part of the response to a FOIA request.

If a Party is required to disclose any Confidential Information (the Disclosing Party) under this Section, a Party supplying such Confidential Information (the Supplying Party) shall have the right to immediately suspend supplying such Confidential Information to the Disclosing Party. In that event, the Parties shall meet as soon as practicable in an effort to resolve any and all issues associated with the required disclosure of such Confidential Information, and the likelihood of additional disclosures of such Confidential Information. If the Parties are unable to resolve those issues within ten (10) days, notwithstanding Section 14.3, the Supplying Party shall have the right to terminate this Agreement immediately.

15.6 Return of Confidential Information. All Confidential Information provided by the supplying Party shall be returned by the receiving Parties to the supplying Party promptly upon request. Upon termination or expiration of this Agreement, a Party shall use reasonable efforts to destroy, erase, delete, or return to the supplying Party any and all written or electronic Confidential Information. In no event shall a receiving Party retain copies of any Confidential Information provided by a supplying Party.

15.7 Equitable Relief. Each Party acknowledges that remedies at law are inadequate to protect against breach of the covenants and agreements in this Article, and hereby in advance agrees, without prejudice to any rights to judicial relief that it may otherwise have, to the granting of equitable relief, including injunction, in the supplying Party's favor without proof of actual damages. In addition to the equitable relief referred to in this Section, a supplying Party shall only be entitled to recover from a receiving Party any and all gains wrongfully acquired, directly or indirectly, from a receiving Party's unauthorized disclosure of Confidential Information.

ARTICLE SIXTEEN
ADDITIONAL PROVISIONS

16.1 Unauthorized Transfer of Third-Party Intellectual Property. In the performance of this Agreement, no Party shall transfer to another Party any Intellectual Property, the use of which by another Party would constitute an infringement of the rights of any non-Party. In the event such transfer occurs, whether or not inadvertent, the transferring Party shall, promptly upon learning of the transfer, provide Notice to the receiving Party and upon receipt of such Notice the receiving Party shall take reasonable steps to avoid claims and mitigate losses.

16.2 Intellectual Property Developed Under This Agreement. If during the term of this Agreement, the Parties mutually develop any new Intellectual Property that is reduced to writing, the Parties shall negotiate in good faith concerning the ownership and licensing of such Intellectual Property.

16.3 Indemnification. Each Party will defend, indemnify, and hold the other Parties harmless from all actual losses, damages, liabilities, claims, expenses, causes of action, and judgments (collectively, "Losses"), brought or obtained by any non-Party against such Party, only to the extent that such Losses arise directly from:

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

(b) Any claim that such Party violated any copyright, patent, trademark, license, or other intellectual property right of a non-Party in the performance of this Agreement;

(c) Any claim arising from the transfer of Intellectual Property in violation of Section 16.1; or

(d) Any claim that such Party caused bodily injury to an employee of another Party due to gross negligence, recklessness, or willful conduct of such Party.

16.4 Limitation of Liability. Except as set forth in this Article: (a) no Party shall be liable to another Party, directly or indirectly, for any damages or losses of any kind sustained due to any failure to perform its obligations under this Agreement, unless such failure to perform was malicious or reckless; and (b) any liability of a Party to another Party shall be limited to direct damages, and no lost profits, damages to compensate for lost goodwill, consequential damages, or punitive damages shall be sought or awarded.

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

16.6 Liability to Non-Parties. Nothing in this Agreement, whether express or implied, is intended to confer any rights or remedies under or by reason of this Agreement on any person or entity that is not a Party or a permitted successor or assign; provided, that nothing in this Section shall affect the rights or obligations of any Reciprocal Entity under a Reciprocal Coordination Agreement.

16.7 Force Majeure. No Party shall be in breach of this Agreement to the extent and during the period that such Party's performance is made impracticable by any unanticipated cause or causes beyond such Party's control, and without such Party's fault or negligence, which may include, but are not limited to, any act, omission, or circumstance occasioned by or in consequence of any act of God, labor dispute, act of the public enemy, war, insurrection, riot, fire, storm or flood, explosion, breakage or accident to machinery or equipment, or curtailment, order, regulation or restriction imposed by a Governmental Authority. Upon the occurrence of an event considered by a Party to constitute a *force majeure* event, such Party shall use reasonable efforts to endeavor to continue to perform its obligations as far as reasonably practicable and to remedy the event, provided that this Section shall not require any Party to settle any strike or labor dispute. A Party claiming a *force majeure* event shall notify the other Parties in writing immediately, and in no event later than forty-eight (48) hours after the occurrence of the *force majeure* event. The foregoing notwithstanding, the occurrence of a cause under this Section shall not excuse a Party from making any payment otherwise required under this Agreement.

16.8 Amendment. No amendment of or modification to this Agreement shall be made or become enforceable except by a written instrument duly executed by all of the Parties.

16.9 Headings. The headings used for the Articles and Sections of this Agreement are for convenience and reference purposes only, and shall not be construed to modify, expand, limit, or restrict the provisions of this Agreement.

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

16.11 Notices. A notice ("Notice") shall be effective only if in writing and delivered by: hand; reputable overnight courier; United States mail; or telefacsimile. Electronic mail is not effective Notice. Notice shall be deemed to have been given: (a) when delivered to the recipient by hand, overnight courier, or telefacsimile or (b) if delivered by United States mail, on the postmark date. Notice shall be addressed as follows:

PJM:
Jim Hinton
President, Southern Region
PJM Interconnection, L.L.C.
955 Jefferson Avenue
Valley Forge Corporate Center
Norristown, PA 19403-2497
Tel: (610) 666-4377
Fax: (610) 666-4281

MIDWEST ISO:
Stephen G. Kozey
Vice President and General Counsel
Midwest Independent Transmission System Operator, Inc.
701 City Center Drive
Carmel, IN 46032
Tel: (317) 249-5431
Fax: (317) 249-5912

William Phillips
Vice President, Interregional Coordination & Policy
Midwest Independent Transmission System Operator, Inc.
701 City Center Drive
Carmel, IN 46032
Tel: (317) 249-5420
Fax: (317) 249-5703

TVA: Terry Boston
Executive Vice President
Transmission/Power Supply Group
Tennessee Valley Authority
1101 Market Street, MR 3H
Chattanooga, TN 37402-2801
Tel: (423) 751-6000
Fax: (423) 751-8352

A Party may change its designated recipient of Notices, or its address, from time to time, by giving Notice of such change.

16.12 Governing Law. This Agreement and the rights and duties of the Parties relating to this Agreement shall be governed by and construed in accordance with the Federal laws of the United States of America, including but not limited to federal, and general contract law. Subject to Article Twelve (Dispute Resolution).

16.13 Prior Agreements; Entire Agreement. All prior agreements by or among all the Parties relating to the matters contemplated by this Agreement, whether written or oral, are superseded by this Agreement, and shall be of no further force or effect. For the avoidance of doubt, as provided under Section 3.2, this Agreement does not supersede the JOA.

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
By:

James P. Torgerson
President and Chief Executive Officer

PJM INTERCONNECTION, LLC
By:

Phillip G. Harris
President and Chief Executive Officer

TENNESSEE VALLEY AUTHORITY
By:

Terry Boston
Executive Vice President
Transmission / Power Supply

Exhibit M

INTERNATIONAL TRANSMISSION COMPANY, CONT'D

CONTRACT NO.	**212**
CONTRACT PARTY(IES)	City of Wyndotte and the Detroit Edison Company
CONTRACT TITLE	Interconnection Agreement
DATED	March 1, 1978
RATE SCHEDULE NO.	International Transmission Company Rate Schedule No. 23
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**213**
CONTRACT PARTY(IES)	The City of Detroit, MI and the Detroit Edison Company
CONTRACT TITLE	Power Supply Agreement
DATED	October 23, 1991
RATE SCHEDULE NO.	International Transmission Company Rate Schedule No. 32
GFA TREATMENT	CARVE OUT
COMMENTS:	Service under this Contract is part of DTE's network load and conversion will be addressed in the same manner as all network load.

LG&E ENERGY COMPANIES-LOUISVILLE GAS & ELECTRIC COMPANY ("LG&E")

CONTRACT NO.	**214**
CONTRACT PARTY(IES)	Louisville Gas & Electric and Indiana Municipal Power Agency
CONTRACT TITLE	Interconnection Agreement, and as amended thereto
DATED	February 7, 1989
RATE SCHEDULE NO.	31
GFA TREATMENT	OPTION B
COMMENTS:	Duplicate of Contract No. 192

CONTRACT NO.	**215**
CONTRACT PARTY(IES)	Louisville Gas & Electric and East Kentucky Power Cooperative
CONTRACT TITLE	Interconnection Agreement, and as amended thereto
DATED	August 14, 1968
RATE SCHEDULE NO.	25
GFA TREATMENT	JUST & REASONABLE
COMMENTS:	

Issued by: Ronald R. McNamara, Issuing Officer
Effective: October 31, 2003
Issued on: May 16, 2005
Filed to comply with the April 15, 2005 Orders in Docket Nos. ER04-691-001, 006, 009, 010, 019, EL04-104-001, 005, 008, 009. 018 and ER04-106-003, 004, 005 (*Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,042 (2005) and *Midwest Independent Transmission System Operator, Inc.*, 111 FERC ¶ 61,050 (2005))

LG&E ENERGY COMPANIES- LG&E, CONT'D

CONTRACT NO.	**216**
CONTRACT PARTY(IES)	Louisville Gas & Electric and Ohio Valley Electric Cooperative
CONTRACT TITLE	Interconnection Agreement
DATED	
RATE SCHEDULE NO.	Rate Schedule No. 25
GFA TREATMENT	CONVERT TO EMT SERVICE
COMMENTS:	

CONTRACT NO.	**217**
CONTRACT PARTY(IES)	Louisville Gas & Electric and Indiana Municipal Power Agency
CONTRACT TITLE	Interconnection Agreement
DATED	
RATE SCHEDULE NO.	Rate Schedule No. 31
GFA TREATMENT	EXCLUDED FOR GFA PROCEEDINGS
COMMENTS:	

CONTRACT NO.	**218**
CONTRACT PARTY(IES)	Louisville Gas & Electric and East Kentucky Power Cooperative
CONTRACT TITLE	Transmission Lease Agreement, and as amended thereto
DATED	April 17, 1989
RATE SCHEDULE NO.	Docket No. ER98-13-000
GFA TREATMENT	EXCLUDED FROM GFA PROCEEDINGS
COMMENTS:	

CONTRACT NO.	**219**
CONTRACT PARTY(IES)	TVA, CG&E and Louisville Gas & Electric Company
CONTRACT TITLE	Interconnection Agreement, and as amended thereto
DATED	September 23, 1957
RATE SCHEDULE NO.	29 (FERC Docket No. ER95-50-000)
GFA TREATMENT	JUST & REASONABLE
COMMENTS:	No firm transmission service currently taken under this Contract.

LG&E ENERGY COMPANIES-KENTUCKY UTILITIES

CONTRACT NO.	**220**
CONTRACT PARTY(IES)	Kentucky Utilities Company and East Kentucky Power Cooperative, Inc.
CONTRACT TITLE	Interconnection Agreement, and as amended thereto
DATED	October 22, 1994
RATE SCHEDULE NO.	203, ER94-209-000
GFA TREATMENT	CARVE OUT
COMMENTS:	

CONTRACT NO.	**221**
CONTRACT PARTY(IES)	Kentucky Utilities Company and East Kentucky Power Cooperative
CONTRACT TITLE	Transmission Agreement, and as amended thereto
DATED	February 9, 1995
RATE SCHEDULE NO.	ER95-580-000
GFA TREATMENT	JUST & REASONABLE
COMMENTS:	

CONTRACT NO.	**222**
CONTRACT PARTY(IES)	Electric Energy, Inc. and Central Illinois Public Service Company, Illinois Power Company, Kentucky Utilities Company, and Union Electric Company
CONTRACT TITLE	Power Supply Agreement
DATED	September 2, 1987
RATE SCHEDULE NO.	199
GFA TREATMENT	CARVE OUT
COMMENTS:	Duplicate of Contract No. 406. Related to Contract No. 448.

CONTRACT NO.	**223**
CONTRACT PARTY(IES)	City of Owensboro City Utility Commission and Kentucky Utilities Company
CONTRACT TITLE	Agreement
DATED	September 30, 1960
RATE SCHEDULE NO.	Supplement No. 3 to Rate Schedule FPC No. 74
GFA TREATMENT	OPTION A
COMMENTS:	

LG&E ENERGY COMPANIES-KENTUCKY UTILITIES, CONT'D

CONTRACT NO.	**224**
CONTRACT PARTY(IES)	United States of America, acting by and through the United States Atomic Energy Commission, et al.
CONTRACT TITLE	Power Agreement
DATED	October 15, 1952
RATE SCHEDULE NO.	Rate Schedule No. 13
GFA TREATMENT	CONVERT TO EMT SERVICE
COMMENTS:	

CONTRACT NO.	**225**
CONTRACT PARTY(IES)	Tennessee Valley Authority and Kentucky Utilities Company
CONTRACT TITLE	Interconnection Agreement and as amended thereto
DATED	March 22, 1951
RATE SCHEDULE NO.	FERC Rate Schedule 93, Last Filing ER95-1478-000
GFA TREATMENT	JUST & REASONABLE
COMMENTS:	

CONTRACT NO.	**418**
CONTRACT PARTY(IES)	City Utilities Commission of Barbourville; Bardstown Municipal Electric Light & Power; Bardwell City Utilities; The Electric Plant Board of Benham; Berea College; Corbin City Utilities Commission; Falmouth City Utilities; Frankfort Electric & Water Plant Board; City of Madisonville; City of Nicholasville; and Providence Electric Department, Kentucky.
CONTRACT TITLE	Contract for Electric Service and as amended thereto
DATED	1987 to 1990
RATE SCHEDULE NO.	Contracts for Electric Service
GFA TREATMENT	OPTION A
COMMENTS:	

LG&E ENERGY COMPANIES-KENTUCKY UTILITIES, CONT'D

CONTRACT NO.	**419**
CONTRACT PARTY(IES)	City of Paris, Kentucky
CONTRACT TITLE	Interchange Agreement
DATED	September 30, 1967
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	

CONTRACT NO.	**420**
CONTRACT PARTY(IES)	City Utilities Commission of Barbourville; Bardstown Municipal Electric Light & Power; Bardwell City Utilities; The Electric Plant Board of Benham; Corbin City Utilities Commission; Falmouth City Utilities; Frankfort Electric & Water Plant Board; City of Madisonville; City of Nicholasville; Providence Electric Department; City of Paris; and City of Owensboro
CONTRACT TITLE	Various SEPA Contracts
DATED	December 31, 1996
RATE SCHEDULE NO.	
GFA TREATMENT	OPTION A
COMMENTS:	

Exhibit N

Michael S. Beer
Vice President
Federal Regulation and Policy

LG&E Energy, LLC
220 West Main Street
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502-627-3547
502-627-4030 FAX
Cell Phone 502-727-8224
mike.beer@lgeenergy.com

October 6, 2005

Mr. Stephen G. Kozey
Vice President and General Counsel
Midwest Independent Transmission System Operator
701 City Center Drive
Carmel, IN 46032-7574

Re: Status of Withdrawal Discussions

Dear Steve:

Pursuant to our telephone call on October 5, 2005, I wanted to summarize what I believe to be our mutual understanding with respect to the issues described below as they pertain to LG&E's and KU's proposed withdrawal from the Midwest ISO. As we discussed, we have been concentrating primarily on the determination of a methodology for calculating the exit fee, and for identifying the process through which a transition plan will be developed as the Companies' Reliability Coordinator and its Independent Transmission Operator prepare to assume their responsibilities upon the effective date of the withdrawal from the Midwest ISO. While there are other issues to be discussed and resolved prior to that withdrawal, resolution of these issues seem to be most critical prior to the Companies' filing.

Towards that end, we very much appreciate the efforts that you have put forth thus far in preparing your estimate of the exit fee and in providing documentation in support thereof. Based on our conversations this morning, we believe the following to have been discussed and agreed to in principle:

1. Deferred Revenue Balance. The Midwest ISO has reflected as a liability on its balance sheet deferred revenue consisting of a portion of the exit fee that Exelon paid to the Midwest ISO upon its withdrawal. LG&E's and KU's understanding is that this is booked as a liability to reflect the Schedule 10 credit available to Exelon for sales made into the Midwest ISO. With respect to the Companies' exit fee, the Midwest ISO has agreed that in lieu of paying their proportionate share of this entire obligation upon withdrawal, LG&E and KU may pay their proportionate share of the actual Schedule 10 credit earned during each calendar year with payment owed to the Midwest ISO in February of the subsequent year. The obligation to pay a proportionate share of this liability will cease upon expiration of the Schedule 10 credit being available to Exelon.

2. Long-term Operating Leases. The Midwest ISO will review the extent to which there may be termination provisions in the operating leases that are included in this amount. To the extent that such provisions exist, the Midwest ISO has agreed that LG&E and KU shall only be required to pay their proportionate share of any such fees associated with early termination, the same as if the leases were terminated on the withdrawal date.

3. Post-withdrawal Credit. The Midwest ISO agreed that LG&E and KU should be eligible to receive a post-withdrawal credit for the fixed cost component of the Schedule 10, 16, and 17 rates that it would pay for sales made into the Midwest ISO market, to be capped at the amount the amount of the exit fee, all in accordance with the methodology set forth in Schedule 10-A. The actual method of calculating and implementing this credit mechanism is subject to further discussion. The duration of the credit is limited to ten (10) years in length.

4. Due Diligence. In agreeing to pay the exit fee, subject to the adjustments referenced above, the Midwest ISO has agreed that LG&E and KU shall have the right to engage in limited due diligence for the sole purpose of confirming the data provided in support of the Midwest ISO's calculation.

Again, we are very appreciative of the work that has gone into these discussions thus far. If acceptable to the Midwest ISO, LG&E and KU propose to represent the following in their application to FERC:

LG&E, KU and the Midwest ISO have engaged in substantial discussions over issues raised in this application. The Midwest ISO has agreed that the LG&E and KU have the contractual right to withdraw from the Midwest ISO. LG&E, KU, and the Midwest ISO have negotiated the calculation of an exit fee and a transition plan and have reached substantial agreement on the methodology for calculating the exit fee, and are each satisfied with respect to the progress made to date in putting in place an appropriate transition plan. Neither the Midwest ISO, LG&E, nor KU intend to raise either the exit fee calculation or the transition plan as a point of contention in these proceedings. These parties anticipate further discussion on these, and a wide array of other issues arising as a result of this application, and expect to enter into a definitive withdrawal agreement within the next 45 days. That agreement will be appended to this application and made a part of the record of these proceedings.

Please review the foregoing for accuracy and communicate to me any comments or issues that you may have. I am particularly interested in the language that I would propose to include in the application. Comments as soon as possible would be greatly appreciated.

If you have any questions, please call me. Thank you.

Sincerely,

Michael S. Beer

Exhibit O

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Kentucky Office of the Governor
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The Honorable Jim Bunning
U.S. Senator
316 Hart Senate Building
Washington, DC 20510

The Honorable Mitch McConnell
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Exhibit P

UNITED STATES OF AMERICA
BEFORE THE
FEDERAL ENERGY REGULATORY COMMISSION

LG&E Energy LLC	)	**Docket No. ER06-___-000**
	)	
Louisville Gas & Electric Company, *et al*.	)	**Docket No. EC98-2-___**
	)	
Louisville Gas & Electric Company, *et al*.	)	**Docket No. EC00-67-___**
	)	
E.ON AG, *et al*.	)	**Docket No. EC01-115-___**

NOTICE OF FILING
(   )

Take notice that on October 7, 2005, LG&E Energy LLC, together with and on behalf of its public utility operating company subsidiaries Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") (collectively, "Applicants"), filed an application with the Commission seeking acceptance of certain rates, terms, and conditions necessary for them to: (i) withdraw from the Midwest Independent Transmission System Operator, Inc. and regain operational control of their respective transmission systems; (ii) install a third party to act as reliability coordinator for their transmission facilities; and (iii) install an independent third party to act as tariff administrator for their transmission system. Further, Applicants request a Commission finding that their withdrawal from the Midwest ISO (together with the operation and administration of their Transmission System by the Independent Transmission Organization and Reliability Coordinator) satisfies certain merger conditions previously proposed by Applicants and approved by the Commission.

Any person desiring to intervene or to protest this filing must file in accordance with Rules 211 and 214 of the Commission's Rules of Practice and Procedure (18 CFR 385.211 and 385.214). Protests will be considered by the Commission in determining the appropriate action to be taken, but will not serve to make protestants parties to the proceeding. Any person wishing to become a party must file a notice of intervention or motion to intervene, as appropriate. Such notices, motions, or protests must be filed on or before the comment date. Anyone filing a motion to intervene or protest must serve a copy of that document on the Applicant. On or before the comment date, it is not necessary to serve motions to intervene or protests on persons other than the Applicant.

The Commission encourages electronic submission of protests and interventions in lieu of paper using the "eFiling" link at http://www.ferc.gov. Persons unable to file electronically should submit an original and 14 copies of the protest or intervention to the Federal Energy Regulatory Commission, 888 First Street, N.E., Washington, D.C. 20426.

This filing is accessible on-line at http://www.ferc.gov, using the "eLibrary" link and is available for review in the Commission's Public Reference Room in Washington, D.C. There is an "eSubscription" link on the web site that enables subscribers to receive email notification when a document is added to a subscribed docket(s). For assistance with any FERC Online service, please email FERCOnlineSupport@ferc.gov, or call (866) 208-3676 (toll free). For TTY, call (202) 502-8659.

Comment Date: 5:00 pm Eastern Time on (insert date).

Magalie R. Salas
Secretary