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December 29, 2003
VIA HAND DELIVERY

Drop Box
RECEIVED
DEC 29 2003

Thomas M. Dorman, Executive Director
Public Service Commission
211 Sower Boulevard
P.O. Box 615
Frankfort, KY 40602-0615

Re: Case No. 2003-00266, Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.

Dear Mr. Dorman:

Enclosed is the original copy of Testimony by James P. Torgerson, Roger C. Harszy, Jonathan Falk, Michael P. Holstein, and Ronald R. McNamara to be filed in the above-referenced proceeding on behalf of Midwest Independent Transmission System Operator, Inc. The verification pages for Messrs. Falk, Harszy, and McNamara are facsimiles; when the original-signature pages are received, they will be submitted to the Commission. All additional copies of the Testimony, including those served on other parties, contain conformed verification pages.

Because this filing is voluminous and we are using the after-hours filing box, we were instructed not to submit the ten (10) additional copies at this time, but to bring them to the Commission tomorrow. Thank you for your attention to this matter.

Sincerely,

Katherine K. Yunker

Enclosure

cc: Richard A. Raff, Esq.
Service List

JAMES P. TORGERSON

Drop By

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	))))))	CASE NO. 2003-00266

DIRECT TESTIMONY OF

JAMES P. TORGERSON

PRESIDENT AND CHIEF EXECUTIVE OFFICER

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Filed: December 29, 2003

I. Introduction

Q. Please state your name and business address.

A. My name is James P. Torgerson, and my business address is 701 City Center Drive, Carmel, Indiana 46032.

Q. By whom are you employed and in what capacity?

A. I am the President and Chief Executive Officer of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO").

Q. Please describe your professional experience and education.

A. Since December of 2000, I have been the President and Chief Executive Officer of the Midwest ISO. Prior to assuming my position as the Midwest ISO's President and Chief Executive Officer, I was the Midwest ISO's Senior Vice President, Chief Financial Officer and Treasurer. Prior to joining the Midwest ISO in October 1999, I was Vice President, Chief Financial Officer and Treasurer of DPL, Inc. ("DPL") in Dayton Ohio. DPL is a combination gas and electric utility holding company located in west central Ohio. I previously served as Vice President and Chief Financial Officer at Puget Sound Energy, Inc., the company created by the merger of Puget Sound Power & Light Company and Washington Energy Company. Prior to the merger, in addition to being an Executive Vice President, I was the Chief Administrative and Chief Financial Officer at Washington Energy Company. I was also Vice President of Development for Diamond Shamrock Corporation where I also held positions in finance and planning.

I hold a Bachelor's Degree in Business Administration, majoring in accounting, from Cleveland State University.

Q. Have you previously testified in proceedings involving the regulation of public utilities?

A. Yes. I have testified in numerous proceedings before the Federal Energy Regulatory Commission ("FERC") involving the Midwest ISO. I also have testified before the United States Senate and House of Representatives with respect to matters involving the Midwest ISO and the electric power industry generally. Finally, I have testified before and made informal presentations to numerous state commissions regarding matters involving the Midwest ISO, Puget Sound Energy and Washington Energy Company.

Q. What is the purpose of your testimony?

A. First, I will briefly describe the history of the Midwest ISO and its evolution from an independent system operator ("ISO") under FERC Order No. 888 to a regional transmission organization ("RTO") under FERC Order No. 2000. Next, I will provide an overview of the benefits that consumers of electricity, including retail customers, realize as a result of RTOs generally and the Midwest ISO specifically. As I point out below, the other witnesses appearing on behalf of the Midwest ISO in this proceeding discuss these benefits in greater detail. Finally, I will address LG&E and KU's request that the Commission support their efforts to "pursue an exit from MISO, with the aim of operating their transmission system on a stand-alone basis."

II. HISTORY OF THE MIDWEST ISO

Q. When did efforts to establish the Midwest ISO begin?

A. As Messrs. Thompson and Beer describe in their prepared testimony filed on September 22 in this proceeding, even before the FERC issued Order No. 888 in April 1996, efforts were well underway by several Midwestern utilities to establish an ISO in the Midwest.

Those utilities had the foresight to recognize that true non-discriminatory open access to the bulk transmission system would require an entity to manage that system whose interests were independent of the transmission owners themselves. In January 1998, ten transmission-owning utilities, including LG&E and KU, filed an application in Docket No. ER98-24-000 with the FERC seeking its approval to transfer operational control over their transmission facilities to the Midwest ISO. At the same time, the FERC was asked to approve the Midwest ISO's Open Access Transmission Tariff and an agreement governing the rights and obligations of the Midwest ISO and its members in Docket No. ER98-1438-000. In their application seeking approval of the Midwest ISO, the transmission owners emphasized the significant benefits an ISO would provide their wholesale and retail customers, stating:

> If implemented (particularly on a broad scale), this filing will provide very substantial benefits to all market participants <u>and bundled retail and wholesale customers</u> in the Midwest. There should be an overall reduction in the costs of transmitting energy in the region with the elimination of pancaking. All market participants will benefit greatly from this filing because of the lower rates, one stop shopping (i.e., going to one transmission provider instead of many), the establishment of uniform and clear rules, the separation of control over transmission from marketing, regional planning of transmission, and enhanced reliability.

Transmittal Letter of Midwest ISO Participants at 6, FERC Docket No. ER98-1438-000 (filed Jan. 15, 1998) (emphasis added, footnotes omitted).

Q. What caused the Midwest ISO's evolution from an ISO to an RTO?

A. Despite the limited success of Order No. 888 in enhancing competition at the wholesale level, opportunities for undue discrimination and preferential treatment in the provision of transmission service remain an obstacle to realizing the full benefits of competitive electricity markets. In mid 1999, the FERC commenced another rulemaking proceeding to further improve management of the transmission grid in an effort to remedy undue discrimination and enhance wholesale competition.

Prior to the Midwest ISO's becoming operational, that proceeding led to the issuance of Order No. 2000 in which the FERC found that "[r]egional institutions [RTOs] can address the operational and reliability issues now confronting the industry, and eliminate any residual discrimination in transmission services that can occur when the operation of the transmission system remains in the control of a vertically integrated utility." *Regional Transmission Organizations*, Order No. 2000, 65 Fed. Reg. 809 at 811 (Jan. 6, 2000) ("Order No. 2000"). Many market participants shared the FERC's view regarding the need to establish RTOs. Indeed, in its comments to the FERC's notice of proposed rulemaking leading to the issuance of Order No. 2000, LG&E Energy Corp. explained,

> Under the current system, transmission owners' operational decisions, even if well intentioned, are surrounded by a cloud of suspicion that, acting in the name of reliability, the transmission owner has enhanced its position in the generation market. As the [FERC] observes in the NOPR, this perception that the transmission system is not being operated in an even handed manner undermines confidence in the non-discriminatory open access implemented under Order No. 888.

Initial Comments of LG&E Energy Corp. at 3, FERC Docket No. RM99-2-000 (filed Aug. 23, 1999).

The FERC ultimately concluded that the establishment of RTOs would create significant benefits including (1) improved efficiencies in the management of the transmission grid; (2) improved grid reliability; (3) elimination of opportunities for discriminatory transmission practices; (4) improved market performance; and (5) facilitation of lighter-handed governmental regulation. *Order No. 2000*, 65 Fed. Reg. 809 at 825, 829. A study conducted by the FERC staff concluded that full development of RTOs would result in average annual savings of up to $5.1 billion per year over the 2000 - 2015 period. *Id.* at 830.

Q. How did Order No. 2000 affect the Midwest ISO's commencement of operations?

A. In Order No. 2000, the FERC set forth the minimum characteristics a transmission provider must possess and the functions it must perform to be approved as an RTO. That order required, among other things, that a compliant RTO must provide real-time energy imbalance services and a market-based mechanism for congestion management. The Midwest ISO immediately set about to determine the most efficient means to satisfy these functional requirements, which require the close integration of transmission operations and energy market administration.

In January 2001, the Midwest ISO submitted its Order No. 2000 compliance filing showing that it possessed the required characteristics and could perform the functions required of an RTO. The Midwest ISO acknowledged that its initial mechanisms for the provision of imbalance service and congestion management, while adequate to satisfy the minimum requirements of Order No. 2000 to commence operations as an RTO, would eventually have to be replaced by more sophisticated and efficient procedures. The Midwest ISO made a subsequent Order No. 2000 compliance filing on August 31, 2001, describing improvements to its scope and configuration.

On November 9, 2001, the FERC sent a letter to various state commissions seeking their views concerning RTO formation in the Midwest. The Midwest ISO deeply appreciates the support this Commission lended to the Midwest ISO's efforts to commence operations as an RTO, including its joint response submitted with other state commissions in November 2001 to that letter. On December 20, 2001, the Midwest ISO became the first RTO in the nation to be approved by the FERC. In its order approving the Midwest ISO as an RTO, the FERC stated,

> [b]ased on the record before us, <u>and taking into account the views of the majority of the Midwestern State commissions</u>, we conclude that Midwest ISO's proposal most fully complies with the vision and requirements of Order No. 2000, in particular the requirement that an RTO be of sufficient scope, and that the Midwest ISO therefore should serve as the foundation upon which a Midwest RTO should be built.

Midwest Independent Transmission System Operator, Inc., 97 FERC ¶ 61,326 at 62500-62501 (Dec. 20, 2001) (emphasis added).

The Midwest ISO began providing transmission services under its tariff on February 1, 2002. Mr. Michael Holstein, Vice President and Chief Financial Officer, Mr. Roger Harszy, Executive Director of Planning and Engineering, and Dr. Ronald McNamara, Vice President of Regulatory Affairs and Chief Economist, describe the existing services that the Midwest ISO provides today and the services it will provide in the future when it implements day-ahead and real-time energy markets in its region.

III. OVERVIEW OF BENEFITS TO LG&E/KU RETAIL CUSTOMERS AS A RESULT OF THE COMPANIES' MEMBERSHIP IN THE MIDWEST ISO

Q. Has the FERC addressed specifically the benefits of the Midwest ISO to bundled retail customers served by the Midwest ISO's transmission owning members?

A. Yes. In Opinion No. 453-A, which is briefly mentioned by Mr. Thompson in his prepared testimony, the FERC explained the basis for requiring all load, including bundled retail load, to be served under the Midwest ISO OATT:

> Intervenors fail to consider the benefits all users of the regional grid will receive when the grid is operated and planned by a single regional entity instead of multiple local entities whose goals may often conflict. As a result of this move to unified planning and operation of the regional grid, we expect to see more efficient siting of transmission facilities from the regional perspective; i.e., siting

> that follows need rather than arbitrary boundaries such as individual local service territories. This will result in enhanced reliability which will benefit all loads. This is because the non-Midwest ISO-operated facilities, such as those connected to local generation, in this region are integrated with the facilities operated by the Midwest ISO. It is established Commission policy that an 'integrated transmission grid is a cohesive network moving electricity in bulk.' Thus all customers using the grid share in all costs of the grid, because they all benefit. This policy has been affirmed in court. Thus, load served from generation located on an individual transmission owner's system (i.e., located on low-voltage transmission facilities that have not been transferred to Midwest ISO) can not be served reliably without the facilities operated by the Midwest ISO. If those Midwest ISO-operated facilities were to disappear, service to all loads, including bundled retail loads, would suffer greatly. Similarly, more efficient operation of the regional grid, including an effective congestion management scheme, should result in the ability of the regional grid to accommodate greater power flows, and thus more efficient transactions than otherwise possible. This should increase the supply of competing generation available to load-serving entities. Accordingly, we affirm our decision that all such loads should be included in the calculation of the Cost Adder.

Midwest Independent Transmission System Operator, Inc., 98 FERC ¶ 61,141 at 61,412 (Feb. 13, 2002).

Q. Have any state commissions addressed the benefits of the Midwest ISO to bundled retail customers served by the Midwest ISO's transmission owning members?

A. Yes. Most importantly, this Commission has found that LG&E and KU's retail customers benefit from the companies' participation in the Midwest ISO. As Mr. Beer points out in his prepared testimony, in its order approving E.ON's indirect acquisition of LG&E and KU, the Commission stated:

> Transmission capacity and reliability are also concerns to be addressed herein. Historically, LG&E and KU have actively participated in organizations such as the East Central Area Reliability Council and the Midwest Independent Transmission System Operator ("Midwest ISO") which help to ensure the reliability of the bulk power system and which, in turn, <u>have a significant impact on retail electric service.</u> The Commission encourages LG&E and KU to continue active

> participation in these organizations, particularly with respect to maintaining the reliability of the electricity supplied to their customers.

PowerGen plc., Ky. PSC Case No. 2000-095, Order at 22-23 (May 2000) (emphasis added).

Likewise, other state commissions have found that bundled retail customers served by the utilities they regulate benefit as a result of those utilities' participation in the Midwest ISO. For example, the Indiana Utility Regulatory Commission ("IURC") has explained:

> The [IURC] has reviewed the testimony in this matter, and finds that Indiana electric customers should receive directly or indirectly <u>substantial and material benefits</u> from the Joint Petitioners [vertically integrated electric utilities regulated by the IURC], participating as transmission owner members in the MISO. The benefits, as set forth in this matter, include: reliability, enhancement of wholesale generation competition and reduction in costs.

PSI Energy, Inc., IURC Cause Nos. 42257 and 42266 (Dec. 11, 2002).

Q. Is the Midwest ISO creating the benefits that were envisioned by its founding members, this Commission, the FERC and other state commissions?

A. Absolutely. The establishment of the Midwest ISO has already resulted in the creation of significant benefits for its members and other stakeholders. One of the most overlooked benefits created by RTOs is particularly relevant to this proceeding. In Order No. 2000, the FERC noted that its estimate of RTO benefits did not include "merger-like consolidation savings in the transmission grid." *Order No. 2000*, 65 Fed. Reg. 809, 830. But the FERC pointed out that "to the extent that RTOs increase market size and decrease market concentration, the competitive consequences of proposed mergers would become less problematic and thereby help further streamline the Commission's [FERC's] merger decision-making process." *Id.* The FERC's Merger Policy Statement emphasizes the benefits of participation in a regional transmission organization with respect to mitigating market power concerns raised by merger proposals, stating:

> Potential remedies for such market power could include the following. First, a proposal by the applicants to turn over control of their transmission assets to an ISO might mitigate market power. In particular, an ISO might facilitate the implementation of efficient transmission pricing and thereby expand the effective scope of the geographic market.

Inquiry Concerning the Commission's Merger Policy Under the Federal Power Act: Policy Statement, 61 Fed. Reg. 68595 (Dec. 30, 1996), FERC Stats. & Regs. ¶ 31,044 at 30,121 (1996). In its order approving LG&E and KU's merger, the FERC followed its Merger Policy Statement, explaining:

> We believe that ISOs, or perhaps grid companies, can make markets more competitive in a number of ways. First, by separating the control of transmission from generation, they can reduce, if not eliminate altogether, any potential manipulation of the post-merger transmission system. Second, they 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 of suppliers able to reach markets (such as the KU requirements customers destination market) increases, thereby lowering market concentration.

Louisville Gas and Electric Co., 82 FERC ¶ 61,308 at 62,222 (Mar. 27, 1998) (footnotes omitted).

Significantly, LG&E and KU's retail ratepayers have received enormous benefits from the merger of the two companies, which, as noted above, was facilitated in large part by the companies' participation in the Midwest ISO. The net non-fuel savings resulting from the merger during the first five years following the merger was estimated to be $235,867,000. LG&E and KU committed to share those savings with their retail customers, who have already received approximately $140 million in billing credits and lump sum payments as a result of the merger. That benefit is in addition to the joint dispatch savings generated by the merger, which were estimated to save LG&E and KU's retail customers $36 million through the companies' fuel adjustment clauses during the first five years of the merger. Moreover, LG&E and KU recently agreed to issue their retail ratepayers additional billing credits exceeding $160 million through June 30, 2008 as a result of future non-fuel savings created by the merger. Under this Commission's order approving that settlement agreement in Case Nos. 2002-00429 and 2002-00430, LG&E and KU's retail customers may also receive additional benefits as a result of non-fuel merger savings realized after June 2008. Mr. Holstein discusses in more detail the merger-related benefits that were facilitated in part by LG&E and KU's participation in the Midwest ISO.

Q. Are you suggesting that the LG&E and KU merger would not have occurred if the companies had not committed to participate in the Midwest ISO?

A. If LG&E and KU had been unwilling to commit to transfer control over their transmission systems to the Midwest ISO, it is impossible to know whether the FERC would have been willing to approve the merger. For example, in a recent order addressing a merger involving another Kentucky utility, the FERC stated, "if AEP had not agreed to join an RTO, the existence of these unresolved market power concerns could have caused the Commission either to disapprove the merger or place restrictive conditions on AEP's ability to operate." *American Electric Power Co.*, 105 FERC ¶ 61,251 at p. 106, FERC Docket No. EC98-40-000 (Nov. 25, 2003). It is certainly possible that other market power mitigation measures the FERC would have conditioned its approval on would have been unacceptable to LG&E and KU, thereby denying LG&E and KU's retail customers the significant benefits the merger has created. In any event, as Mr. Beer explains in his prepared testimony, the FERC's approval of the merger was in fact based on LG&E and KU's continued participation in the Midwest ISO.

Q. What other benefits have been or will be realized by LG&E, KU and their retail customers as a result of LG&E and KU's participation in the Midwest ISO?

A. LG&E, KU and their retail customers have realized and will continue to realize numerous other benefits as a result of the companies' participation in the Midwest ISO. Mr. Harszy discusses operational and reliability improvements that benefit LG&E and KU's retail customers, including benefits related to enhanced security monitoring, improved outage coordination and long-term regional planning. Dr. McNamara's testimony addresses other economic benefits that LG&E and KU will realize as a result of the companies' continued participation in the Midwest ISO.

Q. Are the benefits that Mr. Harszy and Dr. McNamara discuss quantifiable?

A. Yes. Mr. Jonathan Falk, of National Economic Research Associates, presents testimony that quantifies the economic value of the reliability improvements discussed by Mr. Harszy. Mr. Falk testifies that those reliability improvements reduce the probability of a transmission outage that could result in a loss of load to LG&E and KU's retail customers. Dr. McNamara's testimony provides the Commission a quantitative analysis that compares the impacts of LG&E and KU's continued participation in the Midwest ISO versus their withdrawal. Again, the benefits quantified by Mr. Falk and Dr. McNamara are in addition to the merger savings of almost $340 million that LG&E and KU's retail customers will realize in large part as a result of LG&E and KU's membership in the Midwest ISO.

IV. CONCLUSION

Q. Have you reviewed the prepared testimony filed by LG&E/KU in this proceeding?

A. Yes, I have.

Q. In his prepared testimony, Mr. Thompson states, "[LG&E and KU] now believe that, if the KPSC is willing to support fully their efforts, as discussed below, the Companies should pursue an exit from MISO, with the aim of operating their transmission system on a stand-alone basis." How do you respond to that statement?

A. I firmly believe that the Commission should reject LG&E and KU's proposal. First, LG&E and KU have made clear that their withdrawal from the Midwest ISO will adversely affect their retail customers' rates. As Mr. Holstein explains in his testimony, the withdrawal fee that LG&E and KU will seek to impose on their retail customers if they withdraw is substantial. Moreover, as described in more detail by Messrs. Harszy and Falk and Dr. McNamara, LG&E and KU and their retail customers will be denied substantial future benefits if the companies discontinue their participation in the Midwest ISO. Finally, LG&E and KU's efforts to withdraw from the Midwest ISO and establish themselves as stand-alone providers of transmission service are certain to result in numerous protracted proceedings that will consume significant resources of this Commission and the FERC, as well as the Midwest ISO and numerous other affected stakeholders. In my view, those resources would be much better directed at continued efforts to address and work out fair and equitable solutions to resolve the issues that led to this proceeding in the first instance. The Midwest ISO looks forward to continuing the positive relationship it has enjoyed with this Commission and doing just that.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF INDIANA)
) SS:
COUNTY OF HAMILTON)

VERIFICATION

The undersigned, James P. Torgerson, President and Chief Executive Officer of the Midwest Independent Transmission System Operator, Inc., being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

J. P. Torgerson
James P. Torgerson

SUBSCRIBED and SWORN to before me, a Notary Public, this 19th day of December 2003.

Dorothy M. Shute
Dorothy M. Shute

DOROTHY M. SHUTE
NOTARY PUBLIC, State of Indiana
My County of Residence: Hendricks
My Commission Expires: May 8, 2009

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	))))))	CASE NO. 2003-00266

DIRECT TESTIMONY OF

ROGER C. HARSZY

EXECUTIVE DIRECTOR OF PLANNING AND ENGINEERING

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Filed: December 29, 2003

I. <u>INTRODUCTION</u>

Q. Please state your name and business address.

A. My name is Roger C. Harszy. I work at 701 City Center Drive, Carmel, Indiana 46032.

Q. By whom and in what capacity are you employed?

A. I am employed as Executive Director of Planning and Engineering for the Midwest Independent Transmission System Operator, Inc. (the "Midwest ISO").

Q. Please summarize your educational and professional background.

A. I graduated from the University of Illinois with a Bachelor of Science degree in Electrical Engineering. Before my employment with the Midwest ISO, I was Manager of Operations in the Energy Supply Operations Department of Ameren Corporation. Additionally, I have served as Chairman of the Mid-America Interconnected Network, Inc. ("MAIN") Operating Committee, and I am the current Chairman of the North American Electric Reliability Council ("NERC") Operations Reliability Subcommittee.

Q. Please describe your responsibilities with the Midwest ISO as they relate to this filing.

A. Before October 2003, I was the Midwest ISO Director responsible for area operations. In that regard, it was my responsibility to oversee the Midwest ISO's day-to-day transmission operations so that the Midwest ISO operated in a manner consistent with the safe and reliable operation of the regional grid. In October, I became Executive Director of Planning and Engineering and am now responsible for engineering, modeling and planning at the Midwest ISO.

Q. What is the purpose of your testimony?

A. I explain that reliability on that portion of the regional grid located in the State of Kentucky has been and will continue to be enhanced by Louisville Gas and Electric

Company ("LG&E") and Kentucky Utilities Company ("KU") participating as members of the Midwest ISO, to the benefit of LG&E and KU's retail customers. Additionally, I want to assure this Commission that the Midwest ISO's operators are committed to maintaining grid reliability as their primary responsibility.

Q. What is "reliability" and how does it apply to the Midwest ISO's operations?

A. Put into its most basic terms, reliability is the ability to "keep the lights on." It is the primary goal of operations employees at the Midwest ISO, and it is the paramount goal of any electric grid operator. The Midwest ISO does everything reasonably possible to ensure regional transmission reliability in real-time, from day-to-day, and in the long term.

Q. Have you read the testimony of Mr. Jonathan Falk submitted in this proceeding?

A. Yes, I have read Mr. Falk's testimony.

Q. Do you agree with Mr. Falk's conclusions?

A. Yes, I do. My expertise lies within operations and engineering and, to the extent that Mr. Falk's testimony touches upon operation issues generally, or operation of the Midwest ISO grid in particular, I agree with his conclusions. I also agree with his basic understanding and definition of the issues presented in his testimony. Unless stated otherwise, I use the same terms that Mr. Falk uses to explain my answers herein.

Q. You said that the Midwest ISO seeks to enhance reliability. Where does that obligation originate?

A. As a Regional Transmission Organization ("RTO"), the Midwest ISO is charged with several duties, including the responsibility to provide "short term reliability" for its members. This duty was shifted to RTOs in Order No. 2000 to insure that reliability would not be used by transmission-owning utilities to unfairly deny service to wholesale transmission customers. The role of a distinct "reliability coordinator" was developed by NERC to address the need for a new entity to monitor reliability in a fair, non-discriminatory manner. NERC established standards of conduct to assure impartiality, and adopted procedures to guide reliability coordinators, working with control area operators, in the execution of various tasks.

Originally, NERC referred to this function as "security coordination," but after the terrorist attacks in September 2001, the name was changed to "reliability coordination" to avoid confusion with homeland security programs. Older documents (and people) in the industry may occasionally refer to "security coordination" but I will use the current terminology in my testimony.

Q. Can you briefly describe the communications tools the Midwest ISO uses to perform its reliability coordination function?

A. Yes. The Midwest ISO uses several communications systems to fulfill its obligations as reliability coordinator. We use an extensive voice and data communications network to communicate with control areas and neighboring Reliability Coordinators. Following the blackout of August 14, 2003, the Midwest ISO is upgrading the telephone system to a state-of-the-art, turret-style phone system that will be operational in the first quarter 2004. The Midwest ISO also uses the Midwest ISO Messaging System and the MAPP Communication Network ("MCN") to send broadcast text messages to single entities or large groups within the Midwest ISO reliability region involving the status of facilities within the Midwest ISO region and surrounding areas as appropriate. The Midwest ISO's Blast Phone allows us to communicate with the entire region instantaneously in a minimum time. The Midwest ISO also makes use of the Reliability Coordination Information System ("RCIS") to send broadcast text messages to other Reliability

Coordinators involving system events, system status, and other events affecting the transmission system. Finally, the Midwest ISO makes use of the NERC Hotline to communicate with other Reliability Coordinators and NERC regarding system events, critical facility status, and current or potential threats to the transmission system.

The Midwest ISO conducts a morning reliability call each weekday morning (and more often when needed) with control areas within the Midwest ISO reliability region, and with surrounding Reliability Coordinators. The Midwest ISO, MAIN, and PJM Interconnection, LLC participate during every call, and Independent Electricity Market Operator, Entergy Services, Inc., Tennessee Valley Authority, and Southwest Power Pool may dial into the call as needed. During that call, conditions that have the potential to affect reliability of the grid are discussed, such as: projected peak load for the day, projected reserves, forecasted weather, projected constraints and low available transmission capability, scheduled generation outages, scheduled transmission outages, forced outages over the previous 24 hours, current TLRs, current threat alert levels, and possible seams issues (such as heavier than normal power flows across seams, scheduled or forced outages of equipment across seams, and developing problems in neighboring RTOs).

Q. What other tools do the Midwest ISO's reliability coordinators use?

A. We have highly developed visual tools as well. Our Carmel control center uses a large overview display to show real time conditions of the transmission system throughout the entire Midwest ISO footprint, including facilities in Kentucky. This display has recently been upgraded, and now provides a visual link to individual station one-line diagrams. One-line diagrams allow the reliability coordinators to view real time data and conditions at each of the stations within the Midwest ISO footprint.

The Midwest ISO also uses the Flow Gate Monitoring Tool ("FGMT") to observe selected transmission facilities throughout its reliability coordination footprint. This tool focuses on the current status of "key facilities" in the network and notifies the operator when there is a change in that status that exceeds pre-determined limits. For example, if a key transmission line becomes loaded with a 15% increase in flow, that line will be displayed in a different color and move to the top of the operator's screen.

One of the limitations of the FGMT, however, is the initial decision of which lines are "key facilities" that must be monitored because their loss may create a dangerous condition on the system. This is normally a process of mutual agreement between the Midwest ISO and the control area operators who know their system the best. Since August 14, the Midwest ISO has added over 200 facilities to its FGMT and changed this tool to provide additional logging capabilities and the automatic updating of line outage distribution factors to reflect the real-time condition of the system.

Q. What is the "State Estimator" you referred to?

A. The State Estimator is a highly sophisticated computer model that uses real time measurements from the System Control and Data Acquisition System ("SCADA") supplied by member control areas to provide a periodic calculation of the current condition of the entire system. It does this by calculating values for those points in the system where there are no actual measurements available, thus providing a "state estimation" of the system. The Midwest ISO State Estimator provides a solution of the network every ninety (90) seconds. On every third cycle, that is every four and one-half (4.5) minutes, the model automatically uses the output to make further calculations called Real-Time Contingency Analysis ("RTCA"). The RTCA is a valuable tool because it allows the operator to run "what if" scenarios that illustrate the impacts of losing a line, a generator, or some other element in the system. The RTCA runs 5,500 contingencies or what-if scenarios on the model to determine if the loss of any single element would cause a problem on another element. This is a very powerful tool to evaluate the status of the transmission system. This allows the Midwest ISO to plan for that contingency, and to use that information to relieve congestion in one place without creating a more severe constraint somewhere else in the footprint.

Q. Do all reliability coordinators use these tools?

No, in fact some control areas and reliability coordinators do not use RTCA, and others may use it only on command, when system conditions are degrading. There are other tools, such as status alarms and the FGMT, that allow them to observe system conditions quite well; however, providing transmission service across a large footprint becomes more difficult in the absence of contingency analysis. Most reliability coordinators view RTCA as a valuable tool, and run the analysis on a recurring cycle of a few minutes regardless of system conditions. The Midwest ISO agrees with this approach. We use state estimation/RTCA as our primary reliability tool, and view the FGMT tool as a valuable complementary tool for real-time operations.

At the time of the August 14 blackout, the Midwest ISO's State Estimator had not yet been fully deployed by mapping into the system all of the 230 kV transmission facilities in and around the Midwest ISO footprint. By January 2004, the State Estimator will be fully developed with expanded visibility to include facilities outside the Midwest ISO footprint that might impact flows inside our footprint.

Q. What method does the Midwest ISO use to deal with transmission congestion?

A. Until the Midwest ISO energy markets begin operation in December 2004, the primary tool to relieve congestion is the NERC Transmission Loading Relief ("TLR") procedure.

This is a detailed, highly complex process that attempts to reduce the impact of transactions on the grid until a problem is resolved and the system returns to a normal state. This can be done by curtailing transactions that have already begun, or by holding transactions that are pending, but have not yet begun to flow.

The action levels of TLR range from Level 1, which is an alert notifying other Reliability Coordinators that curtailments are *likely* to occur, to Level 6, which authorizes the Reliability Coordinator to implement emergency procedures, such as load shedding, to mitigate a constraint (Level 0 is the return to "normal"). One frequently issued TLR level in the Midwest ISO is Level 4, Reconfiguration. This involves the transmission provider reconfiguring its system to allow a firm, point-to-point interchange transaction to continue without being curtailed. This can only be done if it does not jeopardize the security of interconnected systems. Reconfiguration often involves the redispatch of generation as the most efficient solution. This can be done by the Midwest ISO internally, or through agreement between the Midwest ISO and neighboring Reliability Coordinators to reconfigure their systems to accommodate a Midwest ISO customer.

The most common TLR in the Midwest is Level 3. This can be an action to reallocate transactions based on firmness of service, or to curtail Non-Firm Point-to-Point Transmission Service to mitigate an operating security limit violation.

Q. **Has the Midwest ISO had occasion to use TLRs in the LG&E/KU area?**

A. Yes. The Midwest ISO refers to this Kentucky zone by its NERC designation, LGEE. I requested my staff to compile information about the TLR activity in the LGEE footprint for 2001, before the Midwest ISO became the Reliability Coordinator for LGEE, and for 2002, after the Midwest ISO began operating as the Reliability Coordinator. The results are shown graphically in the attached Exhibit RCH-1. These are three charts prepared under my supervision by my staff, compiling data relating to the Kentucky region.

Chart 1, labeled "Hours in TLR to Protect LGEE Flowgates for External Contingencies," shows the number of hours that an LGEE flowgate was in TLR for a contingency external to Kentucky in the year prior to and the year following the date the Midwest ISO became the Reliability Coordinator for the LGEE footprint. Based upon the fact that there was no significant change to the configuration of the transmission system in and around LGEE and Kentucky between 2001 and 2002 and to explain such a dramatic increase in contingent overloading of LGEE equipment, it must be assumed that the reliability of the LGEE transmission system and the protection of LGEE equipment from contingencies external to Kentucky improved after the Midwest ISO became Reliability Coordinator.

Q. How do you explain this improvement?

A. The improvement is due in large part to the extensive security monitoring capabilities of the Midwest ISO for facilities both within and outside LGEE, as well as the Midwest ISO's commitment to take appropriate action when system conditions require attention. In other words, the Midwest ISO has a large area of visibility and, as a neutral third-party Reliability Coordinator and a transmission provider, has the ability and incentive to preserve the greatest degree of reliability for the greatest number of transactions when faced with congestion.

Q. Did your analysis reveal supporting data for this conclusion?

A. Yes. Chart 2 labeled "Total Hours in TLR on LGEE Flowgates" shows that in addition to the substantial increase in TLRs issued on LGEE flowgates for contingencies external to Kentucky in the year following the Midwest ISO becoming Reliability Coordinator for the LGEE footprint, the total hours in TLR for <u>all</u> flowgates in LGEE increased in 2002 as well. The chart shows that the number of hours in TLR Level 1 increased by 55% while the number of hours in TLR Level 3 increased by about 2%. TLR Level 4 was not issued for an LGEE flowgate in the year prior to the Midwest ISO becoming Reliability Coordinator.

The dramatic increase in the occurrence of TLR Level 4 in 2002 demonstrates the Midwest ISO's commitment to take additional action under TLR Level 4 to avoid the issuance of a TLR Level 5 – which includes the curtailment of Firm Point-to-Point Transmission Service and generation to load impacts – while at the same time avoiding any overloading situations. Under TLR Level 4, the Midwest ISO has worked with LG&E and KU (and other utilities as appropriate) to identify options and solutions to real-time and contingent overloading of LG&E and KU's equipment through redispatch of generation resources to relieve the potential overloading situation without initiating TLR Level 5. Since becoming the Reliability Coordinator, the Midwest ISO has not issued a TLR Level 5 on any flowgate within the LGEE footprint.

Finally, Chart 3 labeled "LGEE Curtailments Due To TLRs Across Entire Eastern Interconnection" shows that in the first year after the Midwest ISO became Reliability Coordinator for the LGEE footprint, even though the total number of hours in TLR on LGEE flowgates *increased* from the previous year (as shown in the previous chart), LGEE actually experienced a *decrease* in the number of Megawatt Hours (MWH) of transaction curtailments. This holds true both for transactions sourcing out of LGEE and for transactions sinking into LGEE: there were 3,033 fewer MWH curtailed in the former category and 1,190 fewer MWH in the latter.

Q. Are you suggesting that prior to 2002 the LGEE control area was not being operated in a reliable manner?

A. No, that is not what I am suggesting. During my time as a control area operator with Ameren, both LG&E and KU had good reputations for being dependable system operators. However, that operating skill is limited by what you can see within your own control area boundaries and what your neighbors are willing to tell you. Midwest ISO has a much larger picture of system conditions. My point is to emphasize that all things being equal, the reliability of the transmission system in Kentucky has improved using quantifiable metrics, for reasons that have to do with LG&E and KU's participation in the Midwest ISO. Mr. Falk's testimony in this proceeding discusses at length the improved reliability in terms of reducing the probability of load loss. Reliability is not always phrased as "safe v. reckless," but often, as here, with reference to the efficiency and variety of the measures available to deal with transmission congestion. For this reason, I do not agree with the assertion made by Dr. Morey at page 12, line 20 of his testimony, in which he states that LG&E and KU would be better able to control the costs and risks of transmission congestion, and be better able to avoid curtailments, by operating as a stand-alone system. I believe experience, as well as Mr. Falk's testimony, demonstrates that Dr. Morey's assertion is incorrect.

Q. Are there other operational benefits that accrue to LG&E and KU as a result of their membership in the Midwest ISO?

A. Yes. One critical advantage of RTO membership is the ability to coordinate outage schedules. Another is the ability to conduct coordinated planning on a regional basis. Both of these items have an important influence on operational reliability.

Q. Can you explain the value of outage coordination?

A. As a stand-alone system, you have the ability to share information with your neighbors about planned outages. Unfortunately, however, simply sharing information may not prevent your neighbor from taking a line out of service for maintenance right in the middle of a long-term power purchase you were planning for the coming summer. The effect may be that the power you thought you were going to purchase cannot be imported safely into your system. The job of the RTO is to coordinate those outage plans with scheduled transmission transactions. As the ultimate authority, the Midwest ISO has the ability to order a delay in a line outage or generator maintenance schedule to protect regional reliability. In most cases, because the Midwest ISO has a wide regional view, we are able to propose acceptable alternatives to the control areas involved so that the costs of changing outage schedules or reconfiguring transactions are minimized.

Q. Would you also describe the advantages of regional planning for the Commission?

A. Yes. The Commission should not overlook the very real improvements in the planning process which can, for the first time, integrate the LG&E and KU planning needs into a broad regional plan. By planning on this basis, the Midwest ISO is able to detect local system studies that are not well coordinated and, if left unchecked, could degrade reliability of the Midwest ISO footprint, including the Kentucky system. This is the long-term version of the real-time TLR problem which I described earlier. By having a wide regional view, the Midwest ISO is able to protect individual customers and systems from being harmed by the real-time operating and long-term planning decisions of their neighbors.

Q. What specific examples can you give of the benefits to Kentucky of the Midwest ISO planning process?

A. The Midwest ISO is able to monitor and analyze chronic power flow constraints on the Kentucky system, and offer reasonable solutions to system operators. Presently, the Midwest ISO carefully monitors two Kentucky flowgates that have an unusually high level of TLR activity: the Blue Lick-Bullitt County 161 kV line for loss of the Trimble County 345 kV line, and the Ghent 345/138 kV Transformer for loss of the Ghent-West Lexington 345 kV line.

The Midwest ISO's initial analysis shows that in a market where constraints are resolved by efficient generation redispatch, these constraints may not require costly upgrades. They may not be economically significant in a regional market but are significant in a stand-alone system. It is this kind of analysis that brings value to this Commission as it considers the need for, and cost of, future transmission expansion projects by LG&E and KU. The Midwest ISO has no independent authority to order its members to build transmission. Instead, the Midwest ISO works cooperatively with State commissions to insure that local transmission projects are necessary, well coordinated with surrounding systems, and beneficial to consumers.

Q. What is the Louisville AFC Zone?

A. Prior to December 2002, a merchant generator in the Louisville area created problems for LG&E whenever the merchant plant scheduled transactions from that unit. At LG&E's request, the Midwest ISO studied the problem and developed a solution that created a distinct flowgate surrounding the merchant unit that allowed the Midwest ISO to calculate Available Flowgate Capacity for that zone, and monitor its impact on the LG&E flowgates when the merchant dispatched its unit. Our authority as an RTO allowed us to prevent adverse flows, and some curtailments, from continuing to affect the LG&E system.

Q. Why do you think Midwest ISO membership made a difference in solving this problem?

A. If LG&E had been operating outside an RTO, the problem would have required either an agreed solution to be worked out with the merchant plant, or protracted litigation at the Federal Energy Regulatory Commission ("FERC"). Even then, on a day-to-day operating basis, circumstances are going to change and any FERC order or agreed bilateral arrangement is not likely to capture all of the variables likely to affect flows from that zone. By analyzing each request on a day-ahead basis, and in real time, the Midwest ISO is able to use its authority as both a Reliability Coordinator and an RTO to develop a reasonable solution. If one party feels that the Midwest ISO has not acted correctly, it can invoke the Midwest ISO dispute resolution process and ultimately challenge the Midwest ISO at the FERC. It is in the first instance, however, that our ability to act decisively allows us to protect reliability in a way that stand-alone systems cannot.

Q. Does this conclude your testimony?

A. Yes it does.

STATE OF INDIANA)
) SS:
COUNTY OF HAMILTON)

VERIFICATION

The answers in the foregoing testimony are true and correct to the best of my knowledge and belief.

Rog. C. Harszy

Roger C. Harszy

SUBSCRIBED and SWORN to before me, a Notary Public, this 29th day of December 2003.

Heather L. Cain

Heather Cain

NOTARY SEAL STATE OF INDIANA
HEATHER L. CAIN
Hamilton County
My Commission Expires
June 5, 2009

Chart 1

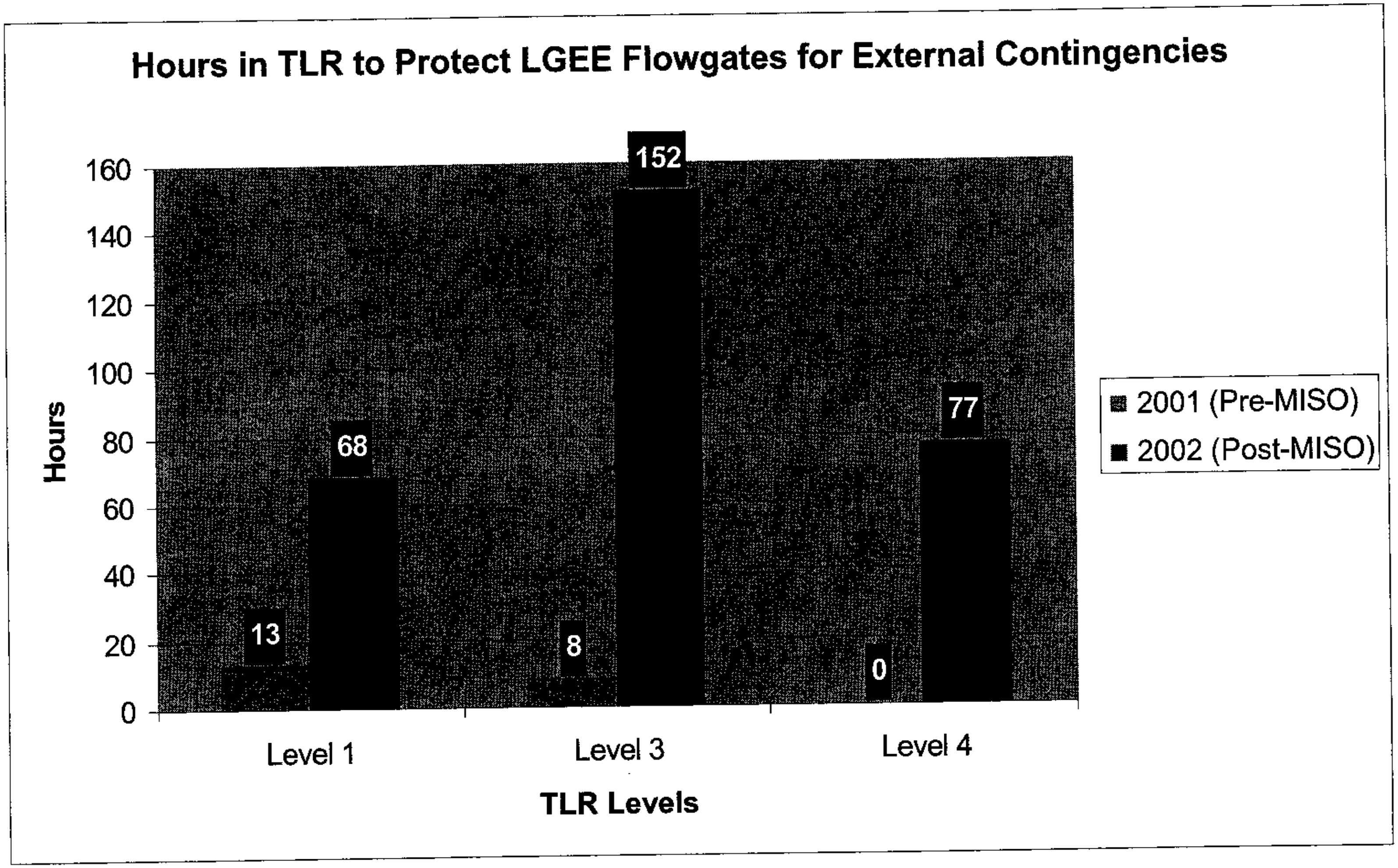

Exhibit RCH-1
Chart 1 of 3

Chart 2

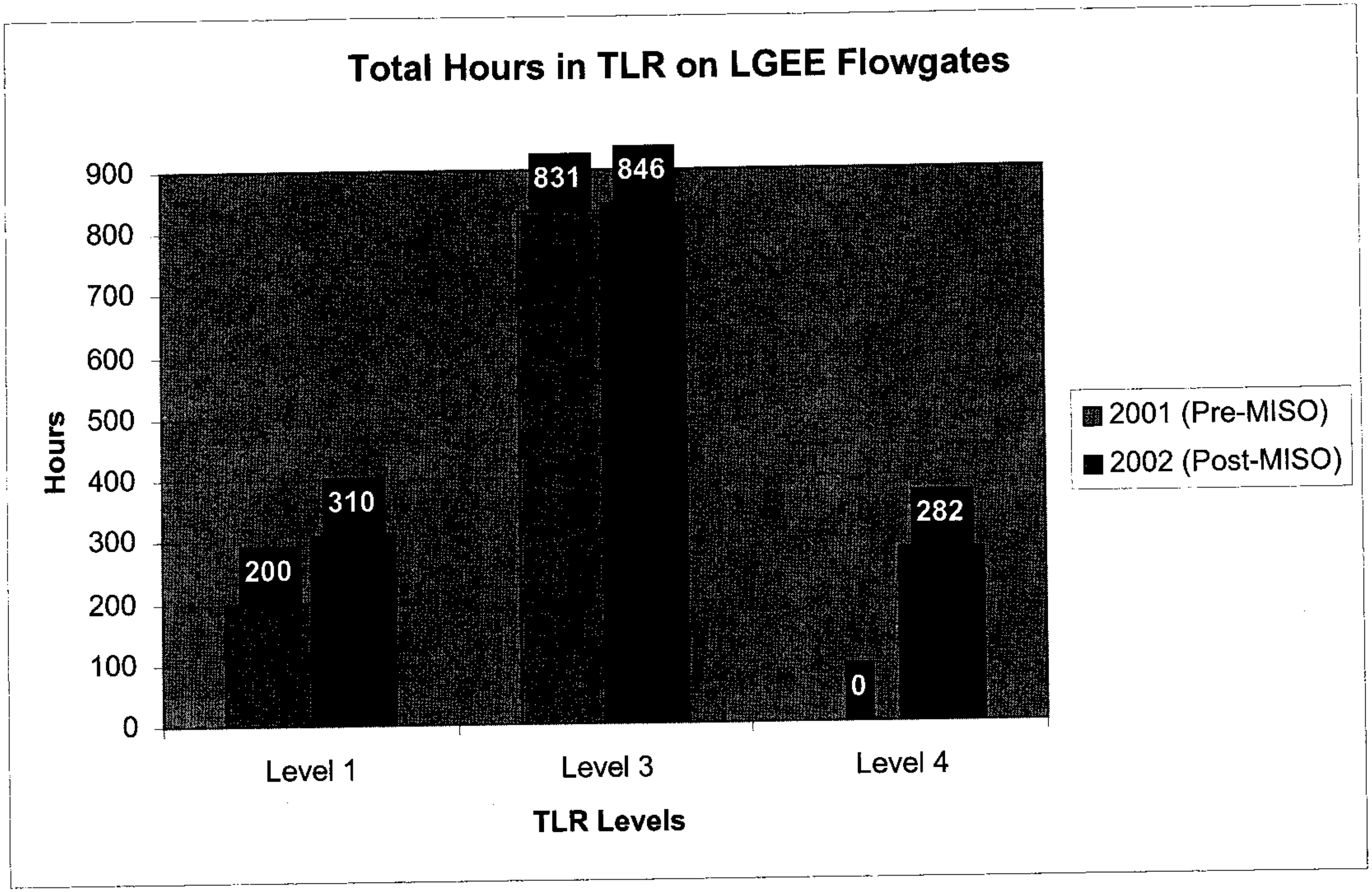

Exhibit RCH-1
Chart 2 of 3

Chart 3

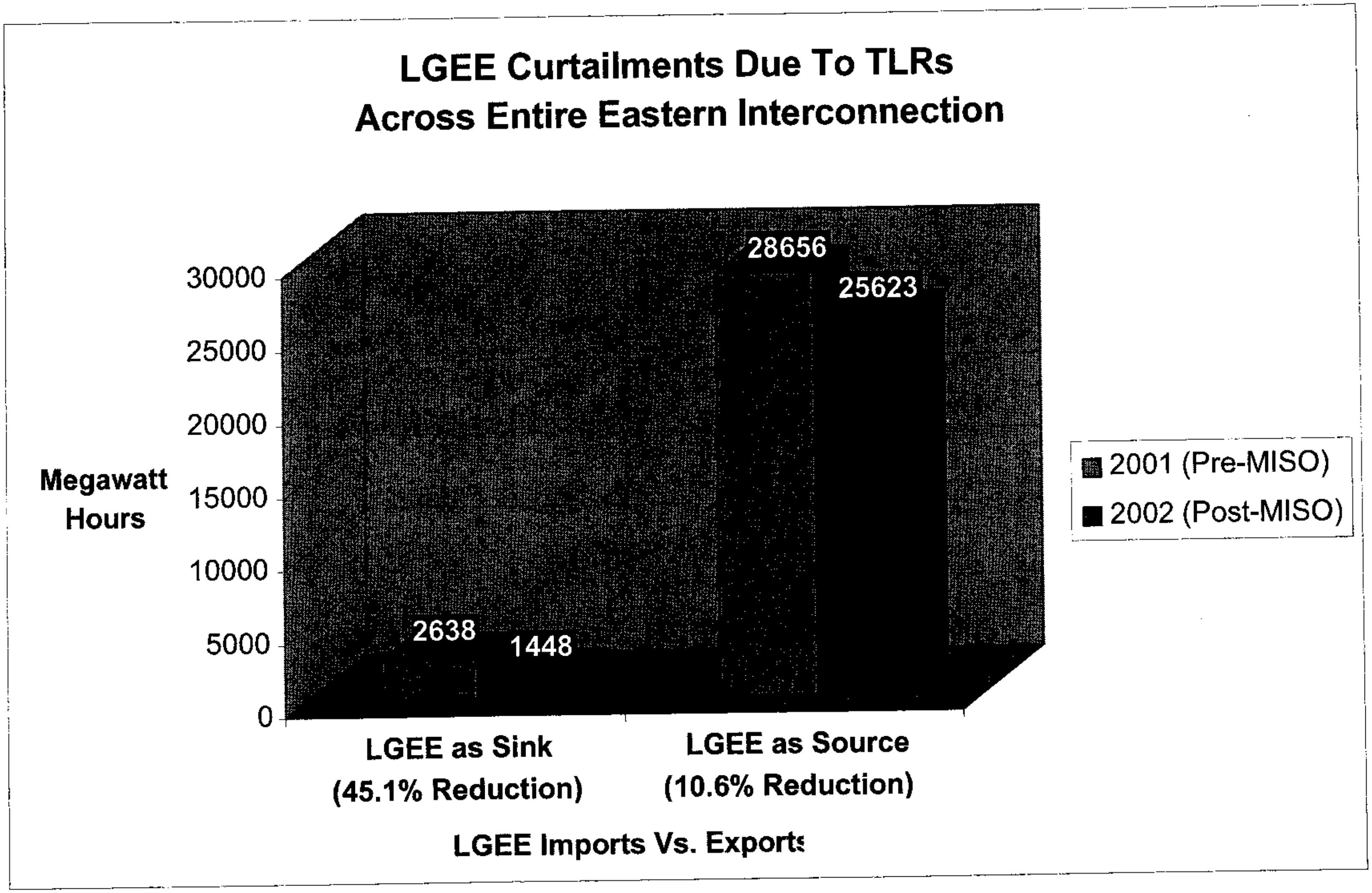

Exhibit RCH-1
Chart 3 of 3

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	)))))	CASE NO. 2003-00266

Direct Testimony of

Jonathan Falk

Vice President, NERA Economic Consulting

on behalf of Midwest Independent Transmission System Operator, Inc.

Filed: December 29, 2003

I. INTRODUCTION

Q. Please state your name and qualifications.

A. My name is Jonathan Falk. I am a Vice President with NERA Economic Consulting where I have been continuously employed for the last nineteen years. I have undergraduate and graduate degrees in economics from Yale University with particular concentration in statistical issues. Much of my work in that time has been concerned with modeling the planning and operation of electric systems, including an understanding of security-constrained transmission systems. In addition, both inside and outside the electricity field, I have conducted numerous statistical analyses. A copy of my *curriculum vitae* is attached as Exhibit__JF-1.

Q. What is the purpose of your testimony?

A. I have been asked by Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") to estimate the reliability benefits that the retail customers of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") have realized and will continue to realize as a result of LG&E/KU's participation in the Midwest ISO.

Q. Have you reached any conclusions?

A. Yes. My overall finding is that the retail customers have reaped substantial reliability benefits as a result of LG&E/KU's membership in the Midwest ISO, and that these benefits can be roughly quantified at either a mean value of $2.7 million per year or a value-at-risk measure of over $50 million. The process by which I have reached this finding can be summarized through three intermediate conclusions.

My <u>first</u> conclusion is that when LG&E and KU transferred functional control over their transmission systems to the Midwest ISO, there was a substantial rise in the number of

Transmission Loading Relief ("TLR") incidents in LG&E and KU service territories. This is true even when controlling for a general increase in the number of TLR incidents.

The cause for this increase stems from two factors. First, there is evidence that LG&E and KU or their security coordinator were not monitoring certain potential contingencies on their system which might have caused the grid to be operated, unbeknownst to LG&E and KU, in a manner which should have required additional Level 4 TLRs. When Midwest ISO took over the security coordinator position, it began to monitor new contingencies which in turn instantiated new high level TLRs. Second, the consolidation of security control facilitates the monitoring of contingencies which cross control area boundaries. Thus, potential problems in bordering areas invoke TLRs in circumstances where they would not be invoked since LG&E and KU (or their security coordinator) would be uninformed of the combined condition.

My <u>second</u> conclusion is that this increase in TLRs made LG&E/KU's system more robust, *i.e.*, it protected against outages. But for these TLRs, there is a risk that there would have been incidents of lost load. This conclusion follows from the purpose of a TLR, which is to keep the system from being operated in a state with heightened probabilities of outage. The increase in TLRs must mean that the pre- Midwest ISO LG&E/KU system was, on some occasions, being run in a state in which the probabilities of outage were higher than design criteria dictate. With enough incidents in these conditions, it is a probabilistic certainty that additional incidents of lost load will occur. The fact that LG&E and KU experienced no outages in this period was a matter of luck.

My <u>third</u> conclusion is that it is possible to give rough bounds for the value of the increased security which the reliability improvements implemented by Midwest ISO provide to LG&E/KU's retail customers. We measure these benefit in two ways: the expected losses which are avoided and by reduced value at risk. The expected gains (through avoided losses) are around $2.7 million per year. While the average benefit is around $2.7 million per year, the distribution is highly skewed. Many years will have no losses at all, while some losses are quite large. The value at risk to Kentucky retail customers is reduced by $50 million at the one percent level. Both of these measures will be explained in more detail below.

Q. How is this testimony organized?

A. In Section II I will explain the reliability benefits of TLRs. Section III will discuss the increase in TLRs which followed Midwest ISO's assumption of the security coordination function. Section IV will then estimate the additional reliability benefits in terms of avoided incidents of lost load. Section V will estimate the expected savings in terms of kilowatt-hours saved. Section VI will value those lost kilowatt-hours using estimates of the value of lost load found in the economics literature. Section VII will bring all the components together to create a distribution of avoided losses and measure Value At Risk.

II. RELIABILITY BENEFITS OF TLRS IN THEORY

Q. What is your understanding of the purpose and implementation of TLRs?

A. The flow of electricity in an electric system is determined by the laws of physics known as Kirkhoff's laws. From moment to moment in an electric system, for a given network, specification of the inputs and outputs of all but one node on the network determines the flows across that network as well as the net output of the remaining node. The goal of running an electric system is to keep current flowing to every demander at an acceptable frequency and voltage.

Each element of the electric system has ratings which determine how much current can flow through it. Excessive current can damage the element, knocking that element out of service, which is not only costly to replace, but can unbalance the system as flows rearrange themselves at the speed of light in accordance with Kirkhoff's laws. The failure of these elements can then, if sufficiently severe or not reacted to promptly, cause a cascading blackout, in which the failure of parts of the network leads to failures in other parts of the network.

To avoid this, system operators must ensure that elements on the network do not exceed their ratings. Unfortunately, the speed with which the electric system reconfigures its flows after an element is knocked out of service does not allow operators enough time to protect the other elements which will be affected by the reconfigured flow. For this reason, the electric system is operated under what is known as contingency planning. Monitoring of the system reveals that certain elements (known as the constrained elements) would be overloaded if some other element (known as the contingent element) fails. System operation must alter the pattern of generation (or, in the worst cases, consumption) where possible to ensure that even if the contingent element fails, the constrained element will not be put unduly at risk.[1]

The procedures to implement these generation patterns are called Transmission Loading Relief, or TLRs. There are various levels of TLRs which indicate the severity of the possible problem and the level of response required. These range from TLR Level 1, which simply notifies reliability coordinators of potential problems ahead, to TLR Level 6 which may require voltage reductions or load shedding to keep the system stable.

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[1] The relevant NERC standard is Policy 2, Subsection A, Standard 1, available at ftp://ftp.nerc.com/pub/sys/all_updl/oc/opman/policy2.pdf.

Q. What is the relationship between a security system violation and the loss of load?

A. By itself, a failure to operate the system within secure limits does not mean that there will be a loss of load. This is particularly true when the insecurity is caused by a post-contingency overload. In this case, all elements on the system are, at the time, operating within normal limits. The link between a post-contingency overload and outage follows three steps. First, the contingent element must fail. Second, the induced excess on the constrained element affected by the contingency must cause it to fail. Third, the failure of the constrained element must lead to an instability which system operators are unable to correct without the shedding of at least some load.

Each of these steps is probabilistic. There is only a probability, not a certainty, that the contingent element will fail. There is only a probability, not a certainty, that this failure will cause a failure in the element considered. Finally, many system instabilities can be controlled without shedding load. Again, however, there is a probability of failure.

Thus, it is important to see that reliable and unreliable are not absolute categories. A system can fail at any time, even when nothing appears to be wrong, and a system might continue to operate well even in circumstances which, with minor perturbations, might have led to disaster.

Q. Is there any way to estimate these probabilities?

A. Yes. By examining the data on TLR incidents and losses of load we can estimate the net probability of a loss of load.

Q. But if there have been no outages, as LG&E and KU claim is the case, wouldn't your estimate of the probability be zero?

A. No. Just because an event with low probability has not occurred does not mean that my estimate of the true probability of the event is zero. Suppose I have a coin which I have flipped five times and it has come up heads each time. While it is true that a two-headed coin would always yield this result, a coin which fell heads "only" 90 percent of the time would have this result 59 percent of the time. Thus, this result would be entirely consistent with a "90 percent heads" coin as well. It would be foolish to conclude that we had proved the coin to be two-headed on the basis of this data.

Q. Wouldn't zero still be the best estimate?

A. No. Although a zero probability may appear to be most consistent with the observed result, it is at one extreme of the range of confidence. Indeed, we can reject zero as being a very good estimate at all, since it implies that not only did no load losses occur, but that there was in fact no possibility under which load losses could have occurred. This simply does not square with our notion of what TLRs are attempting to do or with elementary notions of human fallibility. Impossibility is actually a very bad estimate, while small positive probabilities are entirely consistent with both our observation and our understanding of the process.

III. Increased TLRs

Q. What data have you examined?

A. Midwest ISO has provided me with a list of all TLRs declared in LG&E/KU territory covering the period December 15, 1999 through December 15, 2001 (the pre-Midwest ISO period) and December 16, 2001 through October 22, 2003 (the post-Midwest ISO period). Each TLR lists class (0-6) and the specific flowgate impinged.

Q. What is a flowgate?

A. A flowgate is a collection of network elements considered jointly for the purpose of transmission operation. Thus, a group of lines connecting point A to point B could be considered the flowgate connecting A and B. An aggregate limit on a flowgate is established recognizing the specific transfer capabilities at any point in time between A and B.

Q. Please describe the results of your analysis of that database.

A. The data contain two striking results. First, the pre- Midwest ISO data has the vast bulk of TLRs concentrated at two flowgates: the "Blue Lick-Bullitt County 161 kV line for loss of the Trimble County 345 kV line" and the "11Paddys 161 5Summer 161 L" flowgate. While these flowgates still have significant congestion in the post- Midwest ISO period, there are many additional flowgates which now have engendered TLR incidents. Second, in the pre-Midwest ISO period, there were no Level 4 or above TLR incidents in the LG&E and KU service territories. Once Midwest ISO assumed the security coordinator position, there were 75 days with Level 4 TLRs.

Q. Are these changes simply artifacts of the specific periods?

A. No. The clearest example comes from the increased number of flowgates with TLRs. In conversations with Midwest ISO operators, I have been informed that the discovery was made of several contingencies which were simply not being monitored on the LG&E and KU systems prior to the transfer of control to Midwest ISO. Once those new contingent elements were considered, new constrained flowgates arose, *i.e.*, there were flowgates whose loadings needed to be closely monitored (or, in the case of a Level 4 TLR, rearranged) in case the new contingencies arose.

In addition, there were other contingencies which LG&E and KU and their security coordinator were not readily capable of monitoring, namely contingencies in adjacent areas within the Midwest ISO footprint. It is this seam problem, the proper coordination of security between control areas, that is one of the major impetuses for RTOs and consolidation of security functions. Thus, it is natural that the broadening of the security area leads to an increase in properly monitored contingencies.

Q. Why focus on Level 4 and above TLRs?

A. I focus on the most serious TLRs for two reasons. First, by focusing on those TLRs in which the system is already being run in unsafe conditions, I can limit my analysis to those circumstances with the highest probability of lost load. Level 4 TLRs are declared when the transmission system must be reconfigured to deal with a potentially dangerous situation. Second, the criteria for Level 4 and above are somewhat cleaner. The decision to simply alert the world of potential actions (Level 1) or even to monitor transactions more closely leave substantial scope for categorization. Since the higher levels call for more urgent actions, it is reasonable to suppose that the underlying conditions are better documented.

Q. What do the data show?

A. In the period after December 15, 2001, Midwest ISO declared Level 4 TLRs on 75 different days. Since some of the conditions persisted for multiple hours, there were a total of 804 separate declarations. Thus, over a period of 715 days, there was a Level 4 TLR once every 9.53 days.

By contrast, there were no Level 4 TLRs declared at any point in the pre- Midwest ISO period from January 1, 2000 through December 15, 2001.

Q. But haven't TLRs been increasing in general?

A. TLRs increased dramatically in 2000, and have increased somewhat since. The best available data from NERC (which tabulates Level 2 and above) suggests that Midwest ISO's improved monitoring is in fact responsible for most of the increase. In 2000 and 2001, there were just over 1000 TLR logs. While the number increased to almost 1500 in 2002 and 1800 through November 2003, the real source of that increase is Midwest ISO's addition of approximately 1000 TLRs per year. This was not simply a matter of Midwest ISO picking up TLRs lost to other security coordinators. AEP, for example, declined by only 30 from 2001 to 2002, and only 100 more in 2003. MAIN had a fairly dramatic drop-off of course, but still considerably less than Midwest ISO's gain. Thus, if anything, there was probably a drop-off in aggregate TLRs across the Eastern interconnection (holding security methods constant) between the 2000-2001 and 2002-2003 periods.

Q. What is your conclusion?

A. Using only the Level 4 TLRs and above, it is reasonable to conclude that the post- Midwest ISO period had 38 incidents per year in which potential contingent system instabilities were declared, or 75 events over the period from 1/1/2000-12/15/2001, which would not have been declared had the pre- Midwest ISO security rules been in place. Given the overall constant number of TLRs, it is reasonable to suppose that 75 incidents (or thereabouts) were present in the pre- Midwest ISO security regime without any TLRs being called. Again, the number of undeclared TLR incidents could have been somewhat larger or smaller in this period, but there is no reasonable possibility that the number is zero.

IV. Expected Additional Lost Load Incidents

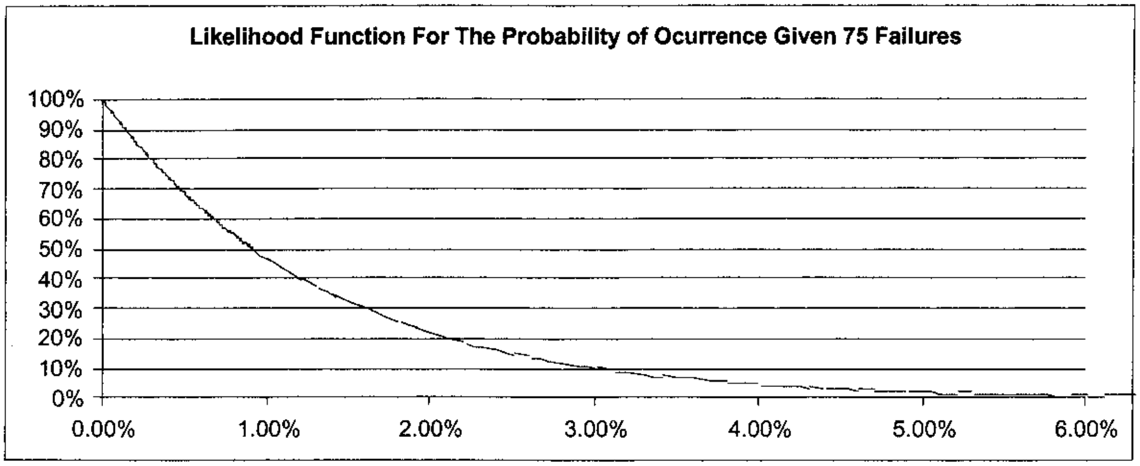
Q. Explain how you move from additional TLR incidents to additional incidents of lost load.

A. The fact that the undeclared TLRs did not lead to lost load is neither unusual nor surprising. A substantial chain of events must arise to actually result in lost load. The purpose of TLRs of any level is to try and minimize the probability that emergency actions will be necessary in order to minimize the probability that those emergency actions will fail.

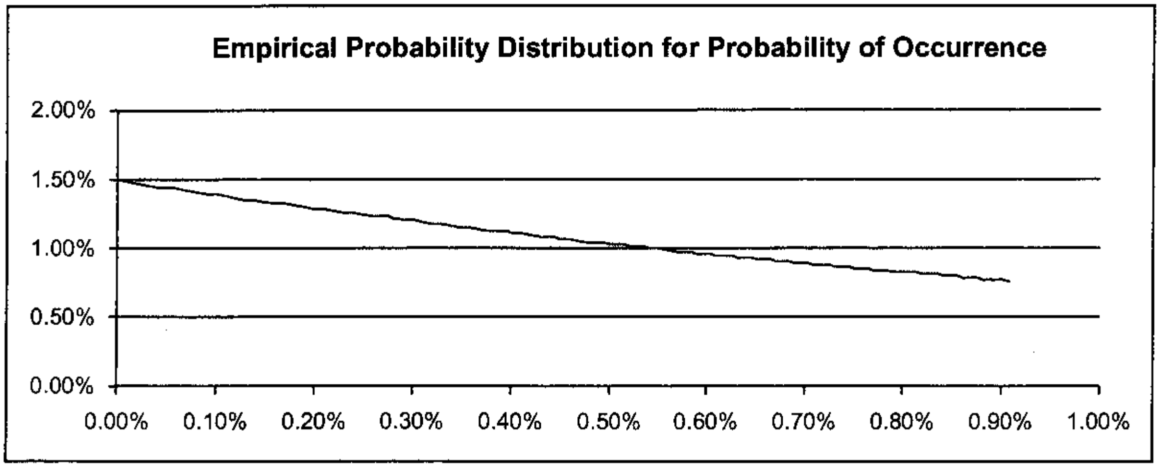
While we cannot precisely estimate the probability of events which did not happen, we can put bounds on those probabilities. At the lower end, the probability would be zero. Of course, we do not actually believe that to have been the probability; otherwise, there would be no reason to monitor those contingencies today. In fact, we believe the probability of an uncontrollable outage to be a small positive value, sufficiently large to warrant the TLR system we have put into place.

We can create a ballpark estimate of this probability by looking at the 75 pre- Midwest ISO Level 4 events per year which led to no outages. Denote the average probability of outage in each of these events by p. Since there were 75 events with no outages, we can calculate, for any level of p, the probability of seeing no outages by the formula $Pr(p)=(1-p)^{75}$.

This relationship, which relates p to the observed data, is known as the likelihood function. While we cannot give precise assurances of the probability of any particular level of p, the likelihood function can be used to give us the relative confidence between any two levels of p. The following chart gives the likelihood function:



One could, in principle, simply sample from the likelihood function to give the probability of any particular value of p. In practice, that would mean that there is a possibility that p was large, but that we were extremely lucky not to have seen any outages. To be conservative, I bound p between zero and the value of p at which we would expect to see zero outages at least 50 percent of the time despite 75 undeclared TLR events. Thus, all possible values of p are consistent with the data. Had we used the full set of likelihoods, estimates of losses would have been much higher. The following chart shows the empirical probability distribution which arises.



Thus, while I cannot create a point estimate of p with any high level of credibility, I can create a likelihood distribution of possible values of p which can be used to estimate the probability of an outage. Not all values of p are equally probable. While a value of 0 has the highest probability, it is only 1.5 times as likely as a value of 0.0054. At this probability level, we would expect to see an outage once every 185 undeclared TLR Level 4 incidents, or about once every five years. Thus, even though this level of outage probability is less likely than zero, it is certainly not inconsistent with the data.

V. Expected Lost Kilowatt-Hours

Q. How do you calculate the lost kilowatt-hours suffered by customers?

A. The best source of this data is the NERC Disturbance Analysis Working Group data. This data has been used to characterize the severity of a typical major disturbance. I have reviewed all DAWG reports since 1990 and analyzed each disturbance. I removed all disturbances which were not clearly labeled as faults of the transmission system, such as those caused by massive snowstorms. The average number of kilowatt-hours lost in a typical disturbance was 2.6 million kWh. While this represents the average, the aggregate losses vary widely across these disturbances. Thus, I use the observed kilowatt-hour losses to create a distribution of kilowatt-hour losses. Using the observed values, I assume that lost kilowatt-hours are distributed lognormally. This distribution is commonly used for events whose values are always positive, and whose variance is of the same order of magnitude as the mean.

I have not included the recent cascading outage, for two reasons. First, it is outside the period for which I had a complete data, so that inclusion would have biased the selection process; second, if one believes that that outage was really a one-in-one-hundred-year occurrence, it would have overrepresented its frequency in the data. That outage is actually instructive as to the mechanism by which small unmonitored problems can, rarely, grow out of control causing massive bad effects. Inclusion of this single event, however, if we could properly judge its frequency, would undoubtedly increase the expected benefits of heightened scrutiny several-fold.

VI. THE VALUE OF LOST LOAD

Q. How does one value the expected kilowatt-hours lost?

A. When outages occur, customers unexpectedly lose electric service. Whatever tasks they were performing at the time become interrupted. While the uses at the margin might be valued at approximately the cost of service, the vast majority of electricity usage is worth far more to the customer than what he pays for it.[2] Every lost kilowatt-hour has a value, the utility which the customer would have enjoyed had he had the electric output. In some cases this will be only a slight annoyance, *e.g.* clocks which have to be reset. In other cases the economic

[2] This follows from the generally low elasticity of electric usage, meaning that substantial increases in prices would be required, particularly in the short run, to deter most electricity usage.

consequences can be much more significant, *e.g.* disruption of industrial processes or the interruption of office equipment and lost productivity.

I should note that by valuing outages in this way only, I am excluding any costs of damage to the electric system itself. Overloads can severely damage pieces of equipment. I am not including any of those costs here.

Q. What value do consumers place on kilowatt-hours not consumed?

A. There have been many studies of the value of lost load. A good survey is presented in Caves, Herriges, and Windle.[3] Another good survey is provided by Pupp and Woo.[4] There are four primary methods by which researchers have derived estimates of the value of lost load ("VOLL"): (1) proxy methods, in which one measures something else which should be related to VOLL; (2) survey methods, in which individuals are asked about their subjective valuations of outages; (3) consumer surplus measures, in which we look at how consumers consume less power as price rises to infer their value of service; and (4) reliability demand models in which we see how electricity demand itself varies cross-sectionally with reliability levels. My reading of the literature suggests that the best estimates of VOLL are around \$6.00 per lost kWh. In any particular outage, however, we might expect to see losses of between \$4.00 to \$8.00 per lost kilowatt-hour, uniformly distributed.

[3] Caves, Herriges and Windle, "Customer Demand for Service Reliability in the Electric Power Industry: A Synthesis of the Outage Cost Literature," Bulletin of Economic Research, 42:2, 1990, pp. 79-119.

[4] Woo and Pupp, "Costs of Service Disruptions to Electricity Customers," Energy, Vol. 17, No. 2, 1992, pp. 109-26.

VII. Aggregate Value Of Increased Reliability

Q. How do you combine these values to derive an overall estimate?

A. With distribution functions derived for (a) the probability of an outage from an undeclared TLR, (b) the kilowatt-hours lost in a typical outage, and (c) the value of lost load from lost kilowatt-hours, we can use Monte Carlo analysis to derive a distribution of benefits from heightened levels of security. The Monte Carlo method simulates many years of experience. First, it uses the distribution of the probability of an outage from an undeclared Level 4 TLR to yield a value for each year, p_i. Next, it uses the binomial distribution with probability p_i to determine the number of outages that year in 38 undeclared TLR incidents. Most years will have none. Some years will have one. A few years will even have more than one. For each outage, we then take a sample from the distribution of lost kilowatt-hours to simulate the kilowatt-hours lost in the outage. Finally, we draw from the distribution of value of lost load to simulate the value of these lost kilowatt-hours. Multiplying the lost kilowatt-hours times the value of each kilowatt-hour gives us an estimate, in this simulation, of losses in a simulated year in which 38 TLR Level 4 incidents went undeclared. We then repeat the process 50,000 times to yield a distribution of losses. These are the losses which are avoided with the heightened level of vigilance which the additional Level 4 TLRs allow.

Q. Have you performed such an analysis?

A. Yes. The chart below summarizes the results.

Percentile	Loss
75	$0
80	$0
85	$0
90	$503,849
95	$4,519,328
96	$6,863,362
97	$11,275,782
98	$20,687,284
99	$50,237,736
Mean	$2,743,363

In over 85 percent of simulated years, there is no loss. However, there are small chances of quite sizeable losses. The mean loss is $2.7 million per year, but there is a one percent chance of a loss of $50 million or more.

Q. What is the significance of the 99th percentile value?

A. While a typical cost-benefit analysis utilizes the mean loss in order to judge the benefits to LG&E/KU's retail customers of the reliability improvements as a result of LG&E/KU's participation in the Midwest ISO, principles of risk management may suggest that this criterion does not tell the whole story. Mean values may be acceptable but large unexpected losses may not. Financial firms in their day-to-day management of their portfolios use the concept of Value At Risk. Under this concept, the portfolio is managed so that there is never more than a one percent chance of losing some set amount, irrespective of how much that cuts average return. The basic notion is that any strategy which makes the firm capable (with some small but not insignificant probability) of a very large loss is unacceptable no matter what. The Value At Risk of $50 million for ignoring the Midwest ISO procedure may be a better statement of the risks to which LG&E/KU's retail customers will be exposed, even if it is not directly comparable to the other values in a cost-benefit analysis.

Q. Are there any other reasons to feel that your estimate is reasonable?

A. Yes. There is good reason to believe that the answer is reasonable independent of the way in which it was derived. If the number were considerably larger, it would imply that overall levels of spending on system security were grossly inadequate. It would suggest that far more resources ought to be devoted to reducing the current level of system insecurity, and that people would readily spend for it. Conversely, were the number much smaller, it would imply that current levels of spending were dramatically overstated, a proposition which has little public support of which I am aware. On the assumption that heightened levels of security are approximately worth, at the margin, what is being spent on them, it is not surprising to see that the increased benefits of reliability are of the same order of magnitude of the increased costs which providing those higher levels of security supply.

Q. If LG&E and KU withdrew from the Midwest ISO, couldn't they simply implement the heightened security procedures to which Midwest ISO has pointed the way, recouping these savings for themselves?

A. I presume they could,[5] but their proposal does not include the higher cost of the higher scrutiny. If they run the system as they ran it before, it is reasonable to assume that they will have similar costs. A higher level of attention to system security will perforce include more costs which have not been included in their testimony.

Q. Does this conclude your testimony?

A. Yes, it does.

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[5] Those reliability advantages which are internalized through a larger MISO footprint may not be achievable at all.

STATE OF New York)
) SS:
COUNTY OF New York)

VERIFICATION

The undersigned, Jonathan Falk, Vice President with NERA Economic Consulting, being duly sworn, deposes and says that he has personal knowledge of the matters set forth in the foregoing testimony, and the answers contained therein are true and correct to the best of his information, knowledge and belief.

Jonathan Falk

Jonathan Falk

SUBSCRIBED and SWORN to before me, a Notary Public, this 29th day of December 2003.

Ann Marie Camera

Notary Public

My County of Residence: Westchester

My Commission Expires: 10/19/06

ANN MARIE CAMERA
Notary Public, State of New York
No. 5003154
Qualified in Westchester County
Commission Expires October 19, 2006

[SEAL]

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JONATHAN FALK

BUSINESS ADDRESS

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Mr. Falk is a Vice President with NERA. He received a B.A., *cum laude*, and M.A. degrees in Economics from Yale University. While completing Ph.D. examination requirements at Yale, he taught courses in microeconomic theory and the history of economic thought.

The bulk of Mr. Falk's work involves NERA's energy practice. He has consulted with a broad variety of industry participants on a number of issues involving the modeling of investment, industry structure and both short- and long-run pricing questions. He has recently been involved in the creation of novel insurance products to transfer price risk in electric markets. He is the current developer of the NERA Electric Market Model, which estimates market clearing prices in heretofore regulated markets. He has studied market power questions in emerging electricity markets and has estimated the social benefits of real-time pricing options for electricity as well as questions of valuation and the financial risks associated with restructured electric markets. He has advised on the structure of market rules, including the benchmarking of contracts between affiliated entities. Finally, he has created a number of models to value flexibility in utility planning.

In NERA's telecommunications practice, Mr. Falk has participated in studies on residential access demand to the telephone system, choice of service among telephone company offerings, optimal pricing structures and estimation of the short- and long-run marginal costs of telephone service.

In environmental economics, Mr. Falk has estimated benefits in recreational activity and increased property values resulting from tighter discharge standards for paper mills and for nuclear power plants.

Exhibit__JF-1

Mr. Falk has worked on several cases involving credit discrimination in automobile and housing markets. He has performed statistical analyses to predict credit decisions.

Finally, in labor economics, Mr. Falk has testified both on statistical estimations of liability in termination and promotion processes and in calculations of lost earnings in both wrongful termination and wrongful death cases. In addition, he has testified in several cases on contract damages and has extensive experience in the estimation of damages arising from contract disputes.

EDUCATION

M.Phil., Economics, Yale University, 1981
M.A., Economics, Yale University, 1980
B.A., Economics, *cum laude*, Yale University, 1978

PROFESSIONAL HISTORY

1984-Present Vice President, National Economic Research Associates, Inc.

Energy Research:

Restructuring: Assisted in market rules design. Valued assets. Assessed financial risks. Assessed market power risks. Design of insurance contracts.

Marginal cost estimation: Developed multi-regional linear programming models for least-cost expansion of electric generation facilities, with associated marginal costs of generation and transmission.

Options modeling: Developed dynamic programming models to estimate benefits of flexibility in electric generation capacity choices.

Locational Elasticity: Estimated models of industrial sensitivity to variations in electric price.

Telecommunications Research:

Models of consumer welfare changes from alternative telephone pricing structures. Estimated optimal local measured service tariffs, choice of service, and the effects of those tariffs on consumer welfare.

Marginal cost estimation: Developed models of marginal cost of telephone loops by class of service for two operating companies. Consultation and preparation of testimony on marginal costs of other telephone system components.

Access demand modeling: Predicted access demands from changes in rates and demographic variables both nationally and regionally for three operating companies.

Labor Economics:

Statistical analysis of terminations in race-, sex-, and age-discrimination cases. Calculation of damages.

Environmental Research:

Damage estimation: Travel-cost model estimation of damages from oil spill.

Benefit estimation: Fishing choice model. Estimated visits to heretofore restricted resources

Cost-benefit studies: Estimations of costs of elimination of discharges and resultant increases in tourism and property values.

Credit Analysis:

Analysis of lending decisions by banks and automobile credit institutions.

Commercial Damages:

Estimates of commercial damages in several adversary hearings including lost profits in the architecture, jewelry, automobile dealership, computer monitor, investment management, vitamin and men's clothing industries.

Microcomputer Consulting:

Internal consulting, including the development of large spreadsheet models, econometric estimation of energy and antitrust models, programming (SAS, FORTRAN and GAUSS), advice on user problems and training.

1981-1983 Independent Consultant.

Worked for various firms including PM Industrial Economics and MRR Associates on the development of econometric models in energy and financial analysis. Also consulted on installation of microcomputer systems.

1980-1981 Teaching Assistant, Yale University.

Taught introductory micro-economics and history of economic thought.

1980 Summer Research Assistant, Energy Policy Division, United States Department of Transportation.

Analyzed energy related transportation issues, including diesel automobiles, coal slurry pipelines, fuel allocation regulations and coal export policies.

PROFESSIONAL ORGANIZATIONS

Faculty, Practising Law Institute, Employment Law Seminar
Member, American Statistical Association

PUBLICATIONS

Guest Editorial regarding the Electric Blackout of August, 2003, *Electricity Journal*, November 2003, pp. 83-84.

"Retroactive Retrograde Retreat: Keeping FERC in The Generation Pricing Business Forever," *Electricity Journal,* August/September 2003, pp. 38-49

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"Substituting Outrage for Thought: The Enron "Smoking Gun" Memos", *Electricity Journal,* August-September *2002,* pp. 13-22

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"What Have We Learned From Asset Sales?" in *The Electricity Journal,* October, 1999 pp. 22-27.

"Reply to Rudkevich, Duckworth and Rosen," in *The Electricity Journal,* December, 1998, pp. 5-7.

"Price-Cost Modeling of Energy Markets: How Many Competitors Do We Need?" in *The Electricity Journal*, July 1998, pp. 44-50.

with Lewis J. Perl, "Optimal Pricing of Electric Power," NERA Working Paper #6, October 1990.

"Investment in Equipment Modernization: The Question of Prudence," in *Telecommunications in a Competitive Environment*, Proceedings of the Third Biennial NERA Telecommunications Conference, April 1989, pp. 103-115.

TESTIMONIES

Testimony on behalf of Kansai in *Kansai Power International Corporation and KPIC North America Corporation, Claimants, v. Morgan Stanley Capital Group Inc., Respondents* in the Court of Arbitration, International Chamber of Commerce Case No. 12 402/JNK, regarding the Western Electricity Market in 2000-2001, risk management, and the economic structure of a joint venture agreement, December 16-17th, 2003.

Declaration on behalf of the PPL Companies before the Federal Energy Regulatory Commission regarding the PJM proposal on offer-capping to mitigate local market power in FERC Docket No. EL03-236-000, October 30, 2003

Expert Affidavit regarding interpretation of facts in a joint venture on behalf of claimant in *Kansai Power International Corporation and KPIC North America Corporation, Claimants v. Morgan Stanley Capital Group, Inc,. Respondent,* Court of Arbitration, International Chamber of Commerce, Case No. 12 402/JNK, September 26, 2003

Declaration regarding statistical model of plaintiff's expert in *Overseas Media, Inc. v. Echostar Satellite Corporation*, Unites States District Court, Southern District of New York, 02 CV 1768 (HB), November 21, 2002.

Affidavit on statistical evidence for age differentials in a reduction in force on behalf of defendant in *Frank Pezzola v. Avon, Inc.*, United States District Court, Southern District of New York, Case No. 00 CIV 9763 (LAP), November 15, 2002

Testimony on behalf of defendant in Doreen Smith v. Bell Atlantic, NYNEX and Robert Olson, regarding lost wages and benefits to plaintiff on May 21, 2002, Cambridge, MA.

Deposition testimony on behalf of defendant in Doreen Smith v. Bell Atlantic, NYNEX and Robert Olson, regarding post-injury damages to plaintiff, April 19, 2002

Declaration in support of plaintiff Pacific Gas And Electric Company's motion for summary judgment on first and second claims for relief in Pacific Gas and Electric Company v. Loretta M. Lynch, Henry M. Duque, Richard A. Bilas, Carl W. Wood and Geoffrey F. Brown in their official capacities as Commissioners of the California Public Utilities Commission, United States District Court, Northern District of California, San Francisco Division, Case No.: C 01-03023 VRW, April 18, 2002

Testimony on behalf of Pacific Gas & Electric, "Prudent Load Bidding in the California Market," filed as Chapter 4 of Application No. 01-09-003, "Application of Pacific Gas and Electric Company in the 2001 Annual Transition Cost Proceeding for the Record Period July 1, 2000, through June 30, 2001," January 11, 2002.

Deposition Testimony in *Sbarro v. Touray et. al.* on behalf of defendant Sbarro, Inc. regarding the plaintiffs' relative promotion rates, Brooklyn, NY, January 7, 2002.

Deposition testimony for defendant regarding the economic damages associated with electricity outages in Santa Cruz County, Arizona in *Sam and Sherri Chilcote; Brad Cook and Jane Doe Cook; Alfread and Frankie Donau; Dave Fenner; Hulsey Hotel Property Management, LLC, dba The Americana Hotel; Alan Anderson dba Ausi Gallery; and Desert Fire Glass Works, LLC vs. CitizensUtilities Company, et.al., No. CV 98-471 (Consolidated with CV 99-081), September 10, 2001.*

Deposition testimony for defendant regarding damages form alleged wrongful termination in *Tadeusz Kluczyk v. Tropicana Products, Inc. et al., Docket No. HUD-L-9698-98*, May 25, 2001.

Deposition testimony for defendant regarding damages arising from alleged wrongful termination in *Robert L. Hennessey v. The State of New Jersey, The Bergen County Prosecutor's Office, The County of Bergen and Charles Buckley, Individually and in his official capacity, Superior Court of New Jersey Law Division – Bergen County Docket No: L-2241-96 Civil Action,* March 12, 2001

Affidavit on behalf of Texas Utilities regarding confidentiality of information provided to Texas Public Utilities Commission, March 27, 2000.

Testimony on behalf of plaintiff regarding statistical estimation of the effect of age-related factors in a reduction in force in *Thomas Hale v. American Telephone & Telegraph Company, AT&T Global Business Communications Systems and Ismael Velez, Jr., Superior Court of New Jersey Law Division: Bergen County Docket No. BER-L-12619-96*, February 3, 2000.

Deposition testimony for defendant regarding damages arising from alleged wrongful termination in *Adel A. Mallemat v. Coopers & Lybrand, LLP*, 97-CV-3871 (JBW), May 20, 1999.

Deposition testimony for plaintiff regarding statistical estimation of the effect of age-related factors in a reduction in force on behalf of plaintiff in *Thomas Hale v. American Telephone & Telegraph Company, AT&T Global Business Communications Systems and Ismael Velez, Jr., Superior Court of New Jersey Law Division: Bergen County Docket No. BER-L-12619-96*, April 5, 1999.

Affidavit for plaintiff regarding Defendants' motion *in limine* in *Thomas Hale v. American Telephone & Telegraph Company, AT&T Global Business Communications Systems and Ismael Velez, Jr., Superior Court of New Jersey Law Division: Bergen County Docket No. BER-L-12619-96*, February 12, 1999.

Rebuttal testimony before the Maryland Public Service Commission on behalf of Baltimore Gas and Electric Company regarding appraisal techniques for the value of electric generation facilities and analyzing the inferences which can be drawn from generating unit sales data in case number 8794, March 22, 1999

Trial testimony criticizing Plaintiff's expert damage report and proposing alternative damage estimate in *Diana Campbell Connolly v. Biderman Industries U.S.A. Inc., 95 Civ. 791 (RPP)* March 9, 1999

Deposition testimony regarding Plaintiff's expert's damage report in *Diana Campbell Connolly v. Biderman Industries U.S.A. Inc., 95 Civ. 791 (RPP)* February 26, 1999

Deposition testimony regarding plaintiff's expert's damage report in *Vincent Hanley vs VCA*, January 25, 1999

Testimony before the Maryland Public Service Commission regarding the calculation of future market prices for electricity on behalf of Baltimore Gas and Electric Company, case Number 8794, July 1, 1998.

Deposition testimony for defendant regarding a statistical model of quit decisions in *Brenda Kay Stoll Madrid, et al vs Oklahoma Gas and Electric Company*, District Court of Oklahoma County State of Oklahoma C.J-91-9695-32, March 17, 1998.

Testimony on behalf of defendant estimating the change in demand for Greenwich Point from elimination of residency requirement on behalf of the Town of Greenwich in *Brendon P. Leydon vs. Town of Greenwich, et. al.,* D.N. CV-95-0143373 S, Stamford, CT, February 20, 1998.

Before the Pennsylvania Public Utility Commission in Docket No. R-00973954.
Oral rejoinder testimony, August 25-26, 1997.
Rebuttal testimony regarding modeling of stranded costs for Pennsylvania Power & Light Company, August 4, 1997.

Victory v. Hewlett-Packard Co., CV 95-3174 (JS).
Deposition testimony for plaintiff regarding statistical analysis of promotions and pay, July 15, 1997.

Isao Kato, individually and on behalf of the estate of Hiroko Kato, deceased, v. County of Westchester. Deposition testimony on behalf of plaintiff, January 10, 1997.
Jordache Enterprises, Inc. v. Larkin Trading Ltd.
Rebuttal testimony, June 13, 1996.
Testimony regarding damages for Larkin Trading, March 13, 1996.

New Haven County Silver Shields, Inc. et al. v. New Haven Department of Police Services et al.
Testimony on behalf of defendant regarding calculation of adverse impact, February 15, 1996.

Mai Langewisch v. Robert T. Wilson and Chesebrough-Pond's, Inc.
Testimony on behalf of defendant regarding lost earnings due to termination, February 6, 1996.

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State of New York against Kraft General Foods, Inc., Nabisco Cereals, Inc., Nabisco, Inc., Philip Morris Companies Inc., RJR Nabisco Holdings Corp., and RJR Nabisco, Inc., 93 Civ. 0811.
Testimony for the Court on econometric evidence of market structure. October 4-6, 1994.

In the Matter of the Arbitration Between Donna Karan Studio and Erwin Pearl Inc.
Rebuttal testimony for Erwin Pearl rebutting criticisms of previous analysis, September 16, 1992.
Testimony for Erwin Pearl regarding lost profits from the termination of the DKNY Jewelry license, April 6, 1992.

In the Matter of the Arbitration Between Raj Ahuja and John Burgee Architects.
Rebuttal testimony, August 2, 1991.

Testimony on behalf of plaintiff regarding the estimation of post-ouster damages to Raj Ahuja, May 9, 1991.

Before the State of Maine Public Utilities Commission, Docket No. 88-111, Volume 1. Supplemental testimony, with John H. Wile, evaluating issues about the relative economics of the proposed Hydro-Quebec purchase, a potential New Brunswick purchase and cogeneration, on behalf of Central Maine Power, June 24, 1988.

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with Michael Rosenzweig, Hamish Fraser, Eugene Meehan and Graham Shuttleworth, "Electricity Markets and Capacity Obligations: A Report for the Department of Trade and Industry," December 13, 2002

with Jesse David, "Economic Impacts of GHI Employment," March 12, 2002.

with David Harrison and Kristina Sepetys, "Prospects for the US Nuclear Industry," prepared for Kansai Electric Company, January 19, 2001

"Critique of the SIC Draft Report," prepared for Texas Utilities, September 3, 1998.

with Mark Berkman, "Economic Impacts of GHI Employment," December 6, 1996.

"Analysis of Damage Sustained by Isao Kato," prepared for law firm of Harold Woolfalk, November 4, 1996.

with Lewis J. Perl and Mark Berkman, "Estimating Employment Effects of Electric Price Increases in US Manufacturing Industries," June 28, 1996.

with Lewis J. Perl and John H. Wile, "Benefits and Costs from the Reduction of Color Effluent From the Champion Mill into the Pigeon River," prepared for Champion International Corporation, April 1988.

with Lewis J. Perl and Timothy J. Tardiff, "Residential Demand for Telephone Service in California," prepared for Pacific Bell, March 23, 1988.

SPEECHES

"Impacts of Fuel Cost Trends on the Relative Economics of Nuclear vs. Conventional Power," Presented at Infocast Conference: Building New Nuclear Power Plants – Assessing the Possibilities, October 16, 2003, Washington, DC

"Economic Impacts of Indian Point Shutdown," presented before joint session of Hudson Valley Technical Societies and Westchester Section of the American Institute of Chemical Engineers, Pleasantville, NY, September 24, 2003

"The Crisis in Financing Independent Power, With Implications for Nuclear Power," Utilities Services Alliance Conference, Santa Fe, New Mexico, June 17, 2003

"Electricity Regulation: The Mess We're In, How We Got There, And The Road Out," presented at a Foundation for American Communications Seminar, Washington, DC, January 27, 2003

"A Contrarian View of Enron," Marsh, Inc. Power Group Conference, Palm Harbor, FL, February 20, 2002.

"Competitive Markets for Power 2001: An Electrical Odyssey," presented at the USA annual meeting, Key Largo, Florida, June 13, 2001

"Electricity Restructuring: The (Pretty) Good, The (Pretty) Bad, and the (Extremely) Ugly," Marsh, Inc. Power Group Conference, Palm Harbor, FL, February 14, 2001.

"Competitive Nuclear Power", presented at the USA Nuclear Annual Meeting, Lake Tahoe, NV, June 14, 2000

"Applying Congestion Pricing in a Decentralized Electricity System," presented at InfoCast Transmission Pricing Conference, Chicago IL, May 2, 2000.

"Electric Price Volatility: Causes, Prospects and Solutions," presented at PURMA Annual Conference, Sturbridge, MA, October 12, 1999.

"Ensuring Accurate Price Forecasting: A Building Block for Asset Valuation," presented at IIR Conference: Buying and Selling Utility Generation Assets, Atlanta, GA, October 1, 1999.

Price-Cost Modeling of Electricity Markets at "New Directions in the Economic Analysis of Market Power," sponsored by National Economic Research Associates, presented at the Four Seasons Hotel, Washington, D.C., June 24, 1998.

Panelist, "Litigating Employment Discrimination," sponsored by the Practising Law Institute, presented at the NYC-Sheraton, June 9th, 1998.

Panelist, "Examination Of Defendant's Economics Expert In A Discrimination Case," presented at the New York State Bar Association Annual Meeting of the Commercial and Federal Litigation Section and Corporate Counsel Section, January 28, 1998.

"Calculating Economic Damages," presented at the Second Annual Employment Law Litigation Institute, sponsored by the Labor & Employment Law Section of the New York State Bar Association and St. John's University School of Law, Queens, New York, May 16, 1997.
"How to Minimize the Impact of Stranded Costs on Credit Valuation," CBI Conference on Credit Ratings for U.S. Utilities and Power Projects, New York, New York, November 22, 1996.

"Statistics for Labor Lawyers: Using Math to Tell a Story," sponsored by National Employment Lawyers Association, New York, New York, October 29, 1996.

Seminar Participant. "How to Hire and Fire," Practicing Law Institute Conference on Employment Law, New York, New York, October 2, 1996.

"Modeling Who Gets RIFed: What's Age Got To Do With It?," luncheon seminar sponsored by National Economic Research Associates, New York, New York, May 1, 1996.

"Econometrics and Marginal Cost," presented at Symposium on Marginal Cost Techniques for Telephone Services, sponsored by The National Regulatory Research Institute, in Seattle, Washington, July 18-19, 1990, and in Columbus, Ohio, August 15-16, 1990.

with Mark Berkman, "Valuing Flexibility in Utility Planning Using Dynamic Programming," presented at Decision Support Methods for the Electric Power Industry Conference, sponsored by Electric Power Research Institute, Cambridge, Massachusetts, May 29-31, 1990.

with Lewis J. Perl, "The Use of Econometric Analysis in Estimating Marginal Cost: The Choice of Functional Form," presented at the International Telecommunications Society, North American Regional Conference, Ottawa, Canada, June 19, 1989.

"Investment in Equipment Modernization: The Question of Prudence," presented at Telecommunications Policy in a Competitive Environment, sponsored by NERA, Scottsdale, Arizona, April 12-15, 1989.

with Lewis J. Perl, "The Use of Econometric Analysis in Estimating Marginal Cost," presented at the Bellcore and Bell Canada Industry Forum, San Diego, California, April 6, 1989.

REPORTS SUBMITTED TO THE FCC

with Lewis J. Perl and Linda McLaughlin, "Econometric Issues Raised by the Further Notice," prepared for Time Warner Entertainment Company, L.P., July 1, 1993.

with Lewis J. Perl and Linda McLaughlin, "Econometric Assessment of the FCC's Benchmark Model," prepared for Time Warner Entertainment Company, L.P., June 18, 1993.

with Lewis J. Perl and Linda McLaughlin, "Econometric Analysis of the FCC's Proposed Competitive Benchmarks," prepared for Time Warner Entertainment Company, L.P., June 16, 1993.

December, 2003

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	))))))	CASE NO. 2003-00266

DIRECT TESTIMONY OF

MICHAEL P. HOLSTEIN

VICE PRESIDENT AND CHIEF FINANCIAL OFFICER

MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Filed: December 29, 2003

I. INTRODUCTION

Q. Please state your name and business address.

A. My name is Michael P. Holstein. My business address is 701 City Center Drive, Carmel, Indiana 46032.

Q. By whom are you employed and in what capacity?

A. I am the Vice President and Chief Financial Officer of the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"). I am responsible for the finance, accounting, internal audit, and credit functions of the Midwest ISO.

Q. Please describe your professional experience and education.

A. Since May 2001, I have been Vice President and Chief Financial Officer of the Midwest ISO. Prior to joining the Midwest ISO, I was Vice President of Strategic Business Initiatives for IPALCO Enterprises, Inc., a holding company that owns Indianapolis Power & Light Company ("IPL"). IPL is an electric utility serving over 400,000 retail customers in central Indiana. I also have worked for Deloitte & Touche in Atlanta, EDS/Energy Management Associates, Inc. in Atlanta, Houston Lighting & Power in Houston and Public Service Company of New Mexico in Albuquerque.

I am a graduate of the University of New Mexico with a Bachelor of Science degree in Civil Engineering and a Master of Business Administration degree with a finance concentration.

Q. Have you previously testified in proceedings involving the regulation of public utilities?

A. Yes. I have testified in numerous proceedings before the Federal Energy Regulatory Commission ("FERC") involving the Midwest ISO. I also have testified before the Arizona Corporation Commission on behalf of Arizona

Electric Power Cooperative, the Wisconsin Public Service Commission on behalf of the Joint QF-Citizens Utility Board Group and the Michigan Public Service Commission on behalf of Midland Cogeneration Venture Limited Partnership.

Q. What is the purpose of your testimony?

A. The purpose of my testimony is to establish that the benefits realized by the retail customers of Louisville Gas & Electric Company ("LG&E") and Kentucky Utilities Company ("KU") as a result of LG&E and KU's participation in the Midwest ISO far exceed the future costs that LG&E and KU's retail customers might incur as a result of the companies' Midwest ISO membership. I will compare the benefits and costs that LG&E and KU's retail customers have realized to date as a result of the companies' participation in the Midwest ISO. I also will compare the benefits that LG&E and KU's retail customers are projected to realize through 2010 as a result of the companies' continued participation in the Midwest ISO to the costs that LG&E and KU's retail customers might incur during that period as a result of the companies' Midwest ISO membership. Finally, I will respond to LG&E and KU's assertion that there are no effective checks on the expenditures of the Midwest ISO's management.

II. <u>Benefits to Date</u>

Q. Please describe the benefits to date that LG&E/KU's retail customers have realized as a result of the companies' participation in the Midwest ISO.

A. The most significant benefits that LG&E and KU's retail customers have realized to date as a result of LG&E and KU's participation in the Midwest ISO can be divided into three categories: (1) benefits that have been realized as a result of the surcredits associated with the companies' merger; (2) reliability benefits; and (3) avoided labor and information systems costs. Mr. Roger Harszy, the Midwest

ISO's Executive Director of Planning and Engineering, and Mr. Jonathan Falk of National Economic Research Associates explain and quantify the reliability benefits that LG&E and KU's retail customers currently enjoy as a result of the companies' participation in Midwest ISO.

Q. How does the companies' merger relate to their participation in the Midwest ISO?

A. LG&E and KU were required to obtain the approval of the FERC prior to consummating their merger. While LG&E and KU's application seeking the FERC's approval of their merger was pending, LG&E and KU committed to participate in the Midwest ISO and filed a separate application requesting the FERC's approval to transfer functional control over their transmission systems to the Midwest ISO. As evidenced by LG&E and KU's own analysis prior to joining the Midwest ISO, the companies clearly viewed their participation in the Midwest ISO as a means to obtain the FERC's approval of their merger. In analyzing the benefits of Midwest ISO participation, the companies concluded that participation "[s]ignificantly reduces market power issues in the merger." *See* Exhibit MPH-1 at page 4. In the merger proceeding, the FERC expressly relied on LG&E and KU's commitment to participate in the Midwest ISO as a means to mitigate market power concerns that the merger presented. Indeed, as Mr. Beer points out in his testimony (on page 4), the FERC's approval of the merger was "based on LG&E and KU's continued participation in the Midwest ISO." *Louisville Gas and Electric Co.*, 82 FERC ¶ 61,308 at 62,222-223 (1998).

Q. What benefits have LG&E/KU retail customers received as a result of the companies' merger?

A. Through the end of 2003, retail customers will have received approximately $140 million in billing credits and lump sum payments as a direct result of the merger.

Q. How was that amount determined?

A. When LG&E and KU sought this Commission's approval of their merger, they presented a study that showed the first five years of the merger should produce cumulative gross non-fuel savings of $313,087,000. LG&E and KU proposed to share with their retail customers fifty percent (50%) of those savings through what the companies referred to as "merger surcredits." The merger surcredits were offset by half the estimated costs to achieve the savings ($38,610,000), which were amortized over five years. On September 12, 1997, the Commission accepted the LG&E and KU proposal, which obligated the companies to pay their Kentucky retail customers[1] $109,292,148 in merger surcredits through June 2003. *See Louisville Gas and Elec. Co.*, Ky. PSC Case No. 97-300, Final Order (Sep. 12, 1997).

Additionally, when this Commission approved the merger, it ordered LG&E and KU, no later than midway through the fifth year of the merger, to present a plan for sharing with retail customers additional merger savings. On January 13, 2003, LG&E and KU submitted a plan to continue paying retail customers merger surcredits under a revised mechanism. LG&E, KU, and the intervenors in that proceeding entered into a settlement agreement, pursuant to which LG&E/KU retail customers will receive additional billing credits in the

[1] A portion of KU's non-fuel merger savings were allocated to non-jurisdictional customers.

amount of $179,720,940 over another five years. The Commission recently approved that settlement agreement. LG&E/KU retail customers should have received approximately $17,972,094 of those merger surcredits through the end of 2003. Additionally, pursuant to the settlement agreement, certain customers received lump sum payments totaling $12,260,189 in lieu of additional merger surcredits.

Q. Did LG&E/KU's retail customers receive other benefits as a result of the merger?

A. Yes. The companies estimated that joint dispatch and fuel savings resulting from the merger would be $36 million during the first five years after the merger. The entire amount of joint dispatch and fuel savings resulting from the merger are passed on to the customers of LG&E and KU through the operation of the companies' fuel adjustment clauses. *See Testimony of Ronald L. Willhite,* Ky. PSC Case No. 97-300 at 15; *Testimony of Wayne T. Lucas,* Ky. PSC Case No. 97-300 at 11.

Q. Please describe the reliability benefits you mentioned earlier.

A. Since it began providing reliability coordination services to LG&E and KU, the Midwest ISO has made a number of improvements to system reliability that benefit LG&E and KU's retail customers. Mr. Harszy describes those improvements in his testimony. Mr. Falk explains that the reliability improvements described by Mr. Harszy have reduced the probability of a transmission outage that could result in a loss of load to LG&E and KU's retail customers. Mr. Falk estimates the mean value of the reduced probability of loss of load to be $2.7 million annually. Moreover, Mr. Falk points out that under one commonly accepted risk management principle, the reliability improvements are valued at over $50 million in any given year. The Midwest ISO has been providing reliability coordination services to LG&E and KU for a little over two years (since December 15, 2001). Accordingly, using Mr. Falk's mean annual value of the reduced probability of loss of load, the total reliability benefits realized by LG&E and KU's retail customers during that period is $5.4 million.

Q. What services does the Midwest ISO provide?

A. In addition to the reliability coordination services described in Mr. Harszy's testimony the Midwest ISO provides the following services as a FERC-approved Regional Transmission Organization:

- Operate and maintain a regional Open Access Same-Time Information System;
- Maintain a FERC-accepted Open Access Transmission Tariff ("OATT") specifying terms and conditions for provision of regional transmission service;
- Evaluate and approve/deny requests for transmission service;
- Evaluate and approve/deny schedules for transmission service;
- Bill customers for transmission and ancillary services;
- Distribute revenue from transmission and ancillary services to transmission-owning members of the Midwest ISO;
- Develop regional transmission system plans.

Q. Were some of the services described above performed by LG&E and KU prior to the transfer of functional control of transmission assets to the Midwest ISO?

A. Yes. The first five services above were previously performed by LG&E/KU personnel.

Q. Have LG&E and KU realized any costs savings as a result of no longer performing these services?

A. Yes. LG&E/KU witness Mathew Morey estimated cost savings of approximately $1 million per year to LG&E and KU from no longer performing these activities. Mr. Morey captured these savings in his Exhibit MJM-1 through his quantification of the additional costs LG&E and KU would incur for additional staffing and systems-related costs necessary if LG&E and KU were to once again perform these activities.

Q. How does the Midwest ISO recover its costs for the services it provides?

A. The Midwest ISO currently recovers its costs of operations, both capital and operating, through what is commonly referred to as Schedule 10 (ISO Cost Recovery Adder) of the Midwest ISO OATT. Schedule 10 contains what is known as a "formula rate." The formula consists of a numerator and a denominator. The numerator is the forecasted costs for the upcoming month adjusted for any over- or under-collection of costs from the prior month. The denominator is the forecasted MWhs of Transmission Service for the upcoming month. The resultant rate per MWh is then multiplied by the actual MWhs of Transmission Service during the month. The ISO Cost Recovery Adder is capped at a maximum rate of $0.15 per MWh through January 31, 2008.

Q. What portion of the Midwest ISO's costs recovered through Schedule 10 has been paid by LG&E and KU's retail customers?

A. It is my understanding that the Schedule 10 costs paid by LG&E and KU are not and have never been reflected in LG&E and KU's base retail rates. That said, there is an Earnings Sharing Mechanism ("ESM") in place whereby earnings above or below a targeted return on equity are shared – 60% to shareholders and

40% to ratepayers. It is my understanding that to date the return on equity has consistently been below the target by an amount such that some costs beyond those in rate base have been recovered from ratepayers in the form of an ESM charge. Thus, one can assume that the ratepayers have to date borne as much as 40% of the amount of Schedule 10 costs that have been charged to LG&E and KU based on the actual MWhs of Transmission Service for the two companies, both for network service and for point-to-point service.

Q. What is the amount of Schedule 10 charges billed to LG&E and KU to date?

A. To date the Midwest ISO has billed and collected from LG&E and KU the amount of $11,862,720 for services provided during the period January 2002 through October 2003. The projected Schedule 10 charge for November 2003 is $331,944 and the projected charge for December 2003 is $373,215 bringing the total for the period January 1, 2002 to December 31, 2003 to approximately $12,567,879.

Q. Based on the foregoing, am I correct that participation in the Midwest ISO, a condition necessary to obtain regulatory approval for the merger of LG&E and KU, has yielded substantial net merger benefits for their retail customers?

A. Yes, that is correct. The net merger benefits to date to LG&E and KU's retail customers equal the total amount of the fuel and non-fuel merger savings that LG&E and KU's retail customers have realized through 2003 plus the economic value of improved reliability since the Midwest ISO began providing reliability coordination services plus the avoided labor and system costs savings associated with the transfer of functional control to the Midwest ISO less the Schedule 10 costs that have been borne by retail customers. As shown below, that amount equals approximately $177,897,279.

Net Benefits to LG&E and KU Retail Customers Through December 2003:

Benefits	
Merger Non-Fuel Savings	$139,524,431
Estimated Merger Fuel Savings	$36,000,000
Reliability *f*(loss of load)	$5,400,000
Labor and System Savings	$2,000,000
Total Benefits	$182,924,431
Costs	
Schedule 10 Costs (40% of total)	$5,027,152
Net Benefits	$177,897,279

Q. Are there additional costs and benefits not reflected in the table above?

A. Yes. These additional costs and benefits relate to the amount of transmission revenue and wholesale power sales margin to be realized under two different scenarios – continued participation in the Midwest ISO and withdrawal from the Midwest ISO. Within the context of this proceeding, these costs and benefits are best evaluated looking forward into the near future when the Midwest ISO implements a market-based, congestion management system as required by the FERC.

Q. Are these two scenarios addressed in your testimony?

A. No. The costs and benefits associated with each of these two scenarios are presented in the testimony of Dr. Ronald McNamara, Midwest ISO's Vice President of Regulatory Affairs and Chief Economist.

Q. **In summary, then, is it your testimony that to date LG&E and KU retail customers have realized substantial merger benefits net of costs associated with the companies' participation in the Midwest ISO, a condition necessary to obtain regulatory approval for the merger?**

A. Yes, it is.

III. <u>FUTURE BENEFITS</u>

Q. What benefits will LG&E/KU retail customers realize through 2010 as a result of the companies' continued participation in the Midwest ISO?

A. The benefits that LG&E and KU's retail customers will realize in the future as a result of LG&E and KU's continued participation in the Midwest ISO include (1) benefits that will be realized as a result of the surcredits associated with the companies' merger; (2) ongoing benefits as a result of improved reliability; and (3) avoided labor and information system costs. Additionally, in the future, LG&E and KU's retail customers will enjoy substantial benefits as a result of the Midwest ISO's implementation of short-term energy markets in its region. Finally, if LG&E and KU remain in the Midwest ISO, LG&E and KU's retail customers will avoid paying the withdrawal fee that would be imposed under the Transmission Owners' Agreement if LG&E and KU withdraw from the Midwest ISO.

Q. What benefits will LG&E/KU retail customers receive during that period as a result of the companies' merger?

A. As described above, under the settlement agreement approved by the Commission on October 16, 2003, LG&E and KU's retail customers will receive an additional $161,748,846 in billing credits as a direct result of the non-fuel savings created by the merger. That amount of billing credits will be paid through June 2008. The costs to achieve the merger savings have been fully amortized, so those billing credits and the lump sum payments made to certain customers will reflect the entire amount of additional merger non-fuel savings realized through June 2008, without offset. Additionally, LG&E and KU's retail customers may receive additional benefits for non-fuel merger savings realized after June 2008.

Q. What are the future benefits of improved reliability through 2010?

A. Based on Mr. Falk's mean value of the reduced probability of loss of load of $2.7 million annually, the reliability benefits through 2010 to LG&E and KU's retail customers as a result of the companies' continued participation in the Midwest ISO is $18.9 million.

Q. What is the sum total of the estimated merger non-fuel savings and reliability benefits through 2010?

A. The sum total of those amounts is approximately $181 million.

Q. What benefits will LG&E/KU retail customers realize as a result of the Midwest ISO's implementation of short-term energy markets in its region?

A. Dr. McNamara addresses benefits that LG&E and KU's retail customers will realize as a result of the Midwest ISO's short-term energy markets. Dr. McNamara's testimony quantifies certain economic benefits that can only be realized by LG&E and KU's retail customers if LG&E and KU continue to participate in the Midwest ISO. Dr. McNamara estimates that those benefits range between $11.3 million and $12.9 million annually. The net present value of the benefits quantified in Dr. McNamara's testimony is $95 million over the period 2005 through 2010. As Dr. McNamara points out, however, if LG&E and KU continue participating in the Midwest ISO, LG&E and KU's retail customers will realize other potentially significant benefits that cannot easily be quantified.

Q. Do the net benefits quantified in Dr. McNamara's testimony include the estimated merger benefits and reliability benefits quantified above as $181 million over the same period?

A. No, they do not.

Q. Do the net benefits quantified in Dr. McNamara's testimony include a projection of the withdrawal fee required under the Transmission Owners Agreement?

A. Yes.

Q. How much is the projected withdrawal fee?

A. If LG&E and KU decide to pursue a withdrawal, the amount of the withdrawal fee will depend on the effective date of the withdrawal. Under Article Five of the Transmission Owners Agreement, a withdrawing transmission owning member is responsible for all financial obligations incurred and payments applicable to time periods prior to the effective date of the withdrawal. Furthermore, under the Transmission Owners Agreement, a transmission owning member's withdrawal is not effective until December 31 of the calendar year following the calendar year in which notice of withdrawal is given. If LG&E and KU were to give the Midwest ISO a proper notice of withdrawal in calendar year 2003, the earliest they could withdraw is December 31, 2004, assuming all regulatory approvals were obtained in that time frame. Based on the Midwest ISO's current and projected obligations as of December 31, 2004, LG&E and KU's estimated withdrawal obligation as of December 31, 2004, would be $38.2 million.

Q. Why is it not the case, as LG&E and KU contend, that they could withdraw from the Midwest ISO within 30 days of an order by this Commission directing them to do so?

A. The provision in Article Seven of the Transmission Owners' Agreement that LG&E and KU refer to was intended to apply only during the preoperational period — that is from the time those companies executed the Transmission

Owners' Agreement until the Midwest ISO commenced operations. This was the position of the original applicants, including LG&E and KU, before the FERC. The language of Article Seven was drafted to cover the securing of state regulatory authority to participate. It begins, "In the event any state regulatory authority refuses to permit participation by a signatory or imposes conditions on such participation which adversely affect a signatory...." Transmission Owners Agreement at Sheet No. 80. The context for the operation of the provision was in the preoperational stage of the Midwest ISO. The potential for an open-ended availability of the 30-day notice and lack of required FERC approval was challenged by certain intervenors in the original FERC docket seeking acceptance of the Transmission Owners' Agreement. *See Midwest Independent Transmission System Operator, Inc.*, 84 FERC ¶ 61,231 at 62,150-151 (1998). In its order approving that agreement, the FERC summarized the Applicants' (including LG&E and KU) response as follows: "Applicants state that only two types of withdrawals are allowed without Commission approval: regulatory out withdrawals and withdrawals by December 31, 1998, each of which, according to Applicants, should be exercised well before Midwest ISO operations begin." *Id.* Based on that interpretation, the FERC concluded:

> We will permit withdrawals from the Midwest ISO Agreement for the reasons stated in Articles V and VII A of the Agreement. However, the Agreement must be revised to clarify that any notice of withdrawal from the Agreement must be filed with the Commission and may become effective only upon the Commission's approval. We also note that any withdrawal from the ISO Agreement by a public utility Transmission Owner after the ISO begins operations will require a Section 203 filing to transfer control over the jurisdictional facilities under the control of the Midwest ISO back to the Transmssion Owner.

Id. at 62,151.

Q. How do the benefits you have described above compare to LG&E and KU's costs of Midwest ISO membership through 2010?

A. LG&E and KU will continue to pay the Schedule 10 charges described above. Additionally, when the Midwest ISO implements the energy markets, including the administration of Financial Transmission Rights, it will recover its costs for providing those services through two new rate schedules in the Midwest ISO OATT: Schedule 16 (Financial Transmission Rights Administrative Service Cost Recovery Adder) and Schedule 17 (Energy Market Support Administrative Service Cost Recovery Adder). As explained by Dr. McNamara, LG&E and KU's retail customers may also incur certain other costs as a result of participating in the Midwest ISO. The table below illustrates the magnitude of the benefits I have described above relative to the projected costs LG&E and KU will incur to participate in the Midwest ISO through 2010.

Benefits to LG&E and KU Retail Customers Through 2010:

Costs Through 2010	
Schedule 10 Costs	$50,000,000
Schedule 16 Costs	$9,000,000
Schedule 17 Costs	$29,000,000
Total Costs	$88,000,000
Benefits Through 2010	
Net Energy Market Benefits	$197,800,000
Merger Surcredits	$161,700,000
Reliability Benefits *f*(loss of load)	$18,900,000
Total Benefits (nominal $)	$378,400,000
Net Benefits (nominal $)	$290,400,000

The table above includes 100 percent of the projected costs to be charged to MWhs of Transmission Service associated with LG&E and KU load in 2004 through 2010 under Midwest ISO OATT Schedules 10, 16 and 17. As I explained above, Midwest ISO's Schedule 10 costs are not currently included in base retail rates. However, LG&E and KU recently announced that they will seek an increase in their retail rates. LG&E and KU's notices to the Commission of the forthcoming rate filings indicated that their application and testimony in support of the rate increases would be filed on December 29, 2003, the same day this testimony is due to be filed in this proceeding. Accordingly, I do not know whether LG&E and KU will seek to include their Schedule 10 costs in their historic test year or will propose some other mechanism by which retail customers would pay a portion of the Midwest ISO's Schedule 10, 16 and 17 costs. The table above is a representation of the effect of fully recovering these costs from retail customers.

Q. **Do you believe the Commission should allow LG&E and KU to recover a portion of their Schedule 10, 16 and 17 costs from their retail customers?**

A. Yes. In fact, I believe it is appropriate for LG&E and KU to include in retail rates all of the costs of the Midwest ISO under Schedules 10, 16 and 17. As noted earlier in my testimony, participation in an RTO was a necessary condition to obtain FERC approval for the merger. As such, the cost of RTO participation should properly be considered a cost to achieve the merger, a merger that has produced substantial and quantifiable benefits for retail ratepayers. Further, given the federal requirement to join an RTO as a means of mitigating market power, it is my opinion that one hundred percent (100%) of the Midwest ISO costs should be included in retail rates as opposed to shared 50/50 or on some other basis between shareholders and ratepayers. Finally, I believe it is appropriate for all Schedule 10 costs to date to be capitalized and recovered through retail rates for the same reasons I believe prospective costs should be included in retail rates.

IV. <u>MIDWEST ISO'S MANAGEMENT OF COSTS</u>

Q. Have you reviewed Mr. Thompson's testimony filed on September 22, 2003, in this proceeding?

A. Yes, I have.

Q. On page 15 of his testimony, Mr. Thompson asserts, "Currently, there are no effective checks on the expenditures of MISO management: because MISO is a non-profit organization with no equity at risk, there is currently no practical means to minimize MISO's expenditures consistent with good business practice." How do you respond to that assertion?

A. The non-profit organization status of the Midwest ISO is that required under the controlling documents associated with the formation of the Midwest ISO, documents prepared by legal counsel for the Transmission Owners and executed individually by each of the transmission owning members of the Midwest ISO. The governance structure of the Midwest ISO, which features an independent Board of Directors and an Advisory Committee composed of representatives of various stakeholder sectors, is that dictated by the Transmission Owners Agreement, prepared by legal counsel for the Transmission Owners and executed individually by each of the transmission-owning members of the Midwest ISO.

Q. Are there benefits to transmission customers of the non-stock, non-profit status of the Midwest ISO relative to a for-profit enterprise with stockholders?

A. Yes. One, the cost of capital is lower given that there is no equity, the most expensive form of capital because the greater the risk, the higher the expected return. This translates into lower financing costs on the $200 million of currently outstanding senior unsecured notes of the Midwest ISO. The most recent notes, issued in February 2003, bear interest at the rate of 4.62%. By contrast, under the Earning Sharings Mechanisms approved for LG&E and KU, each company's target return on equity is 11.5%. Second, the Midwest ISO returns any revenue in excess of its expenses each and every month, resulting in lower costs to transmission customers relative to a for-profit entity that produces earnings in the form of revenues in excess of expenses. However, precisely because the Midwest ISO returns all revenues in excess of expenses each month, it has no equity in the form of earnings to serve as a cushion to absorb expenses in excess of revenues. As such, the Midwest ISO must recover all of its costs in order to be able to meet its contractual and financial obligations.

Q. Are there means to minimize the Midwest ISO's expenditures consistent with good business practice?

A. Yes. The capital and operating budgets of the Midwest ISO are developed by its management team, reviewed by the Finance Subcommittee of the Advisory Committee, reviewed by the full Advisory Committee in November and December, and reviewed by the Board of Directors of the Midwest ISO in November and December of each year. The ultimate decision on the budget resides with the Board of Directors, which consists of seven independent members plus the President and CEO of the Midwest ISO. Per Appendix F, Section 4.2 of the Transmission Owners Agreement, the Board must include individuals with the following qualifications:

- Four (4) shall have expertise and experience in corporate leadership at the senior management level or board of directors level, or in the professional disciplines of finance, accounting, engineering, or utility laws and regulation;

- One (1) shall have expertise and experience in the operation of electric transmission systems;
- One (1) shall have expertise and experience in planning of electric transmission systems; and
- One (1) shall have expertise and experience in commercial markets and trading and associated risks.

Transmission Owners Agreement at Sheet No. 177. In its November 22, 2002 Order accepting proposed changes to the Midwest ISO OATT to establish separate cost recovery adders for the establishment of FTR services and the energy market services, the FERC included the following:

> We do, however, recognize that RTO development costs must be carefully contained in order to maximize the net benefits of RTO formation and the creation of a common market to customers. Therefore, while we recognize the importance of RTOs recovering their costs associated with the services they provide, we also recognize the importance of cost control measures in system development. Consequently, we expect Midwest ISO's Board of Directors to be proactive in this area. The Midwest ISO Agreement provides that the management of all property, business and affairs of Midwest ISO shall be vested in the Board of Directors. Thus, we expect the Board of Directors to guard against any unreasonable costs being incurred.

Midwest Independent Transmission System Operator, Inc., 101 FERC ¶ 61,221 at 61,957 (2002) (footnote omitted). The FERC went on to order the filing of progress reports every sixty (60) days on expenditures related to the creation of FTR and energy market services as a means of monitoring the effectiveness of the cost control measures of the Midwest ISO. *Id.* at 61,961-962.

Q. Are the members of the Midwest ISO Board of Directors accountable to the members of the Midwest ISO?

A. Yes. The members of the Board of Directors of the Midwest ISO are elected by the members of the Midwest ISO. Each independent Board member serves a staggered three-year term with annual elections held in December of each year for those members whose three-year terms are expiring. In addition, the Transmission Owners Agreement provides for removal of directors outside of the annual election process under certain circumstances.

Q. Does this conclude your testimony?

A. Yes, it does.

STATE OF INDIANA)
) SS:
COUNTY OF HAMILTON)

VERIFICATION

The answers in the foregoing testimony are true and correct to the best of my knowledge and belief.

Michael P. Holstein

SUBSCRIBED and SWORN to before me, a Notary Public, this 26th day of December 2003.

Heather Cain

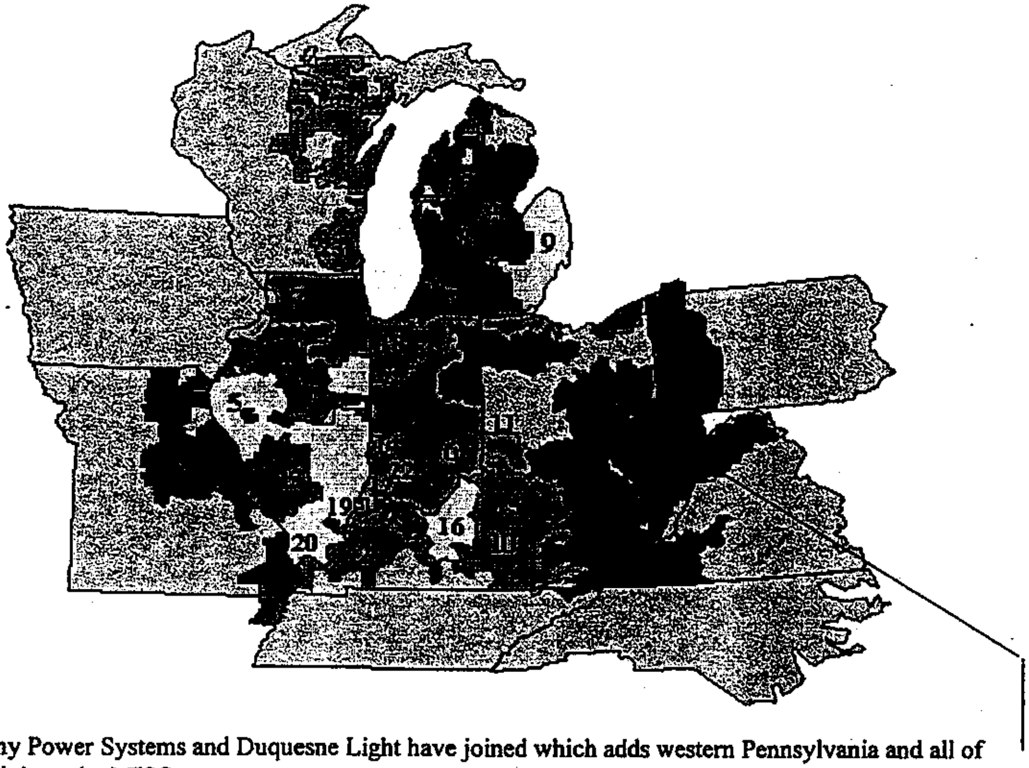
NOTARY PUBLIC
NOTARY SEAL
STATE OF INDIANA
HEATHER L. CAIN
Hamilton County
My Commission Expires
June 5, 2009

MIDWEST ISO

Midwest ISO Briefing

October 3, 1997

Map of the Midwest ISO



* Allegheny Power Systems and Duquesne Light have joined which adds western Pennsylvania and all of West Virginia to the MISO.

1. AMERICAN ELECTRIC POWER
2. BIG RIVERS COOPERATIVE
3. CENTERIOR ENERGY
4. CENTRAL ILLINOIS LIGHT
5. CENTRAL ILLINOIS PUBLIC SERVICE
6. CINERGY
7. COMMONWEALTH EDISON
8. CONSUMERS POWER
9. DETROIT EDISON
10. EAST KENTUCKY POWER COOP
11. HAMILTON, OHIO
12. HOOSIER ENERGY RURAL ELECTRIC COOPERATIVE
13. ILLINOIS POWER
14. INDIANA MUNICIPAL POWER AGENCY
15. KENTUCKY UTILITIES
16. LOUISVILLE GAS & ELECTRIC
17. MICHIGAN PUBLIC POWER AGENCY
18. NORTHERN INDIANA PUBLIC SERVICE
19. SOUTHERN INDIANA GAS & ELECTRIC
20. SOUTHERN ILLINOIS POWER COOP
21. UNION ELECTRIC
22. WABASH VALLEY POWER AUTHORITY
23. WISCONSIN ELECTRIC
24. WISCONSIN PUBLIC SERVICE
25. WOLVERINE POWER COOPERATIVE

Details of the MISO Operating Agreement as of September 30, 1997

Structure:

- 27 companies involved in development (Allegheny and Duquesne have joined)
- The MISO will be set up as a non-profit corporation. (Possible tax exempt.)
- A 7 member board will direct the operation of the MISO. The board will be elected by members (transmission users and owners who join the ISO) from a slate of candidates provided by an independent search firm. Board members shall not have any affiliation or financial interest in any owner or user.
- Advisory panels made up of owners, users, and other non-user stakeholders will be established to work with the Board.
- The present thought is to debt finance all initial MISO capital requirements. Owners would still have internal costs to interface with the MISO. (For LG&E: < $1 million)

Operation and Planning:
The MISO will -

- Operate all member transmission facilities 100KV and above.
- Coordinate planning for all member transmission facilities 100KV and above.
- Reserve and schedule transmission service and collect tariffs for all member transmission facilities under FERC jurisdiction.
- Not operate as a control area but will coordinate schedules with member control areas.
- Arrange for and coordinate the provision of ancillary services and transmission losses.
- Not operate a power exchange or be involved in marketing.

Transmission Pricing:

- Transition Period - Years 1 through 6 (2000 to 2005)
  Postage Stamp rate based on the zonal price (transmission rate of the individual owner) of the load if the load is in the MISO. Rate based on the average MISO rate if the load is not located in the MISO.

- Post Transition - Past Year 6 (2006 and beyond)
  Postage Stamp rate based on the average MISO rate for all load in the MISO (including bundled retail load) unless MISO grants special zonal rate for a owner or customer.

This is not the pricing structure that the Kentucky companies were seeking, since bundled load and load under existing transmission agreements pay the average MISO rate after the transition period. The protection of a petition process and automatic withdrawal rights was added in order to provide some protection for low cost owners like those in Kentucky.

Revenue Allocation:

- Transition Period
  Revenue for transmission where generation and load are in the same zone, for existing transmission contracts, for sales on sole ties to non-MISO control areas and for purchases of border companies from non-MISO control areas are directly allocated to the owner. Other revenue is allocated 25% on owner's revenue requirement and 75% on actual flows.

- Post Transition
  All revenue is allocated based on revenue requirements up to the revenue requirement of the owner. Excess revenue will be retained to make up for future shortfalls or used to reduce transmission rates.

Ability to Petition for Special Rates and Automatically Withdraw:

After year 6, any owner or customer can petition the MISO Board for special remedies due to the cost impacts of the MISO average rate. If the owner or customer is not satisfied with the Board's decision, they can take their case to dispute resolution or to FERC. If an owner is not satisfied, the owner has automatic withdrawal rights from the MISO (pre-approved by FERC).

Filing Schedule:

<u>October 22:</u>	Members are to indicate their intentions as to joining the initial filing.
<u>November 6:</u>	Members joining the initial filing are to submit a signature page to be held in trust by the MISO attorney. The attorney will make availble a list of signatory companies to all members and ask members if they wish to include their signature page in the filing.
<u>November 10:</u>	FERC Filing

Impact of LG&E (and KU) Joining Initial Filing

Kentucky PSC Position:

The Kentucky PSC staff had expressed serious concerns about the impact of the original pricing proposal on the rates of Kentucky consumers. Their position has been that they have no problem with customers who have retail choice paying the MISO rates but do not feel that regulated bundled customers should pay that rate unless the host utility is actually using the MISO transmission system.

Benefits:

- Provides a large geographic power market for one transmission rate, although LGE /KU would have access to this market if the MISO is formed without our membership.
- FERC is pushing the ISO concept and joining would place us in favorable light
- Significantly reduces market power issues in the merger.
- Could produce additional transmission revenues during transition period. (Still being studied)
- LGE/KU remains at the table in the formation process of the MISO.

Costs:

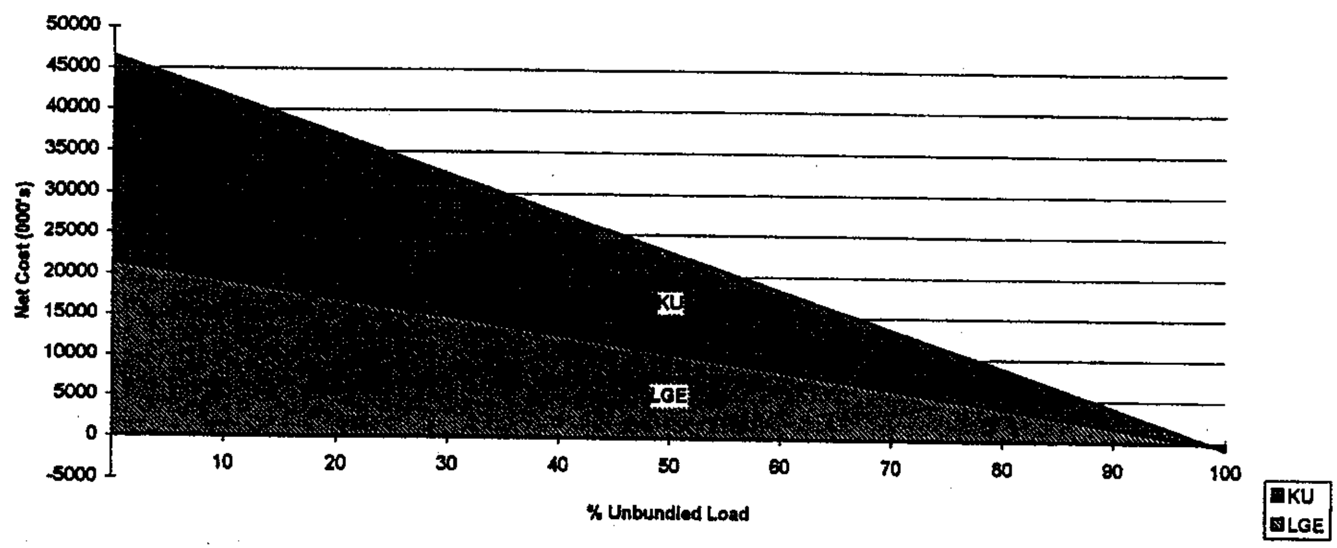
- LGE/KU loses control over transmission assets of 100KV and above.
- LGE/KU could be forced to install new transmission for which we would receive our revenue requirement.
- Raises transmission costs for selling power to immediate neighbors, although this would still occur if all our immediate neighbors were members of an ISO.
- If there is still significant bundled retail load in 2006 and LGE/KU does not receive special treatment or withdraw, LGE/KU could be required to pay up to $47 million more annually to the MISO than it receives in revenue requirement.

Net Transmission Cost for LGE/KU to Join MISO

During Transition: A net gain of approximately $2 million. Also, LGE/KU would not be required to charge themselves a transmission charge for off-system sales of approximately $ 7 million.

After Transition: The cost will depend on the amount of bundled retail load still be served by LGE/KU and whether the MISO (and FERC) would grant special rate relief. After transition there is an option to withdraw.

Net Cost of Joining MISO After Transition



Alternative 1:

Participate in Initial Filing

Benefits:
- We remain at the table as the MISO is being formed.
- If FERC requires changes to agreement, we would have input into those changes.
- Helps in the merger transmission issues.

Concerns:
- We would be committed to the MISO for first six years.
- We would lose control of all transmission above 100KV.
- We may be required to build transmission lines.
- We would need a strategy in place for withdrawing after six years if a significant portion of our load was still bundled.

Alternative 2:

Don't participate in initial filing and join later if necessary.

Benefits:
- We will know FERC's position on the agreement.
- Allows us more time to study the impact of the MISO on LGE/KU and the industry.

Concerns:
- MISO agreement could be modified to something that is less acceptable with no opportunity for input from us.
- We would have to manage the perception of LGE/KU not participating in an entity which FERC feels will enhance competition.

COMMONWEALTH OF KENTUCKY

BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

Investigation into the Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.	)	CASE NO. 2003-00266

Direct Testimony of

Dr. Ronald R. McNamara

Vice President of Regulatory Affairs and Chief Economist

Midwest Independent Transmission System Operator, Inc.

Filed: December 29, 2003

INTRODUCTION

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

A. My name is Ronald R. McNamara. I work at 701 City Center Drive, Carmel, Indiana 46032, as Vice President of Regulatory Affairs and Chief Economist for the Midwest Independent Transmission System Operator, Inc. ("Midwest ISO").

Q. Please describe your educational and professional background.

A. I graduated in 1979 from the University of California, Irvine, with a B.A. degree in Economics and a B.A. degree in Social Ecology. I received an M.A. degree and a Ph.D. in Economics from the University of California, Davis, in 1991 and 1993, respectively.

I have worked as an economist in academia, as well as in the public and private sectors. From 1995 to 1998, as the Manager of Research and Development for the Electricity Market Company Ltd. and as a Senior Adviser for Putnam, Hayes and Bartlett Asia-Pacific, I was involved in designing and implementing the electricity market in New Zealand. I have also worked as a Director at the Queensland Competition Authority the Queensland (Australia) state regulatory commission, Duke Energy as the General Manager of Regulatory Affairs (Australia), Enron and American Electric Power. Prior to joining the Midwest ISO, I was employed at American Electric Power as a Director of Government Affairs where I was primarily involved in electricity market design. In this capacity, I represented AEP as a member of the Participants Committee at the New England ISO, the Management Committee at the New York ISO, the Advisory Committee at SeTrans, the Advisory Committee at the Midwest ISO, and the PJM Members Committee. Additionally I served on the Southwest Power Pool Board of Directors in 2001.

SUMMARY

Q. What is the purpose of your testimony?

A. My testimony addresses an issue identified by the Kentucky Public Service Commission in its Order initiating this investigation, specifically, whether the net benefits to Louisville Gas and Electric ("LG&E") and Kentucky Utilities Company ("KU") of continued membership in the Midwest ISO are likely to be positive. A detailed explanation of the benefit / cost analysis conducted to address that issue is attached to my testimony as Exhibit RRM-1.

Q. Was Exhibit RRM-1 prepared at your direction?

A. Yes. The benefit / cost analysis was prepared at my direction and under my supervision.

Q. Please summarize your testimony.

A. The analysis summarized in my testimony reaches three primary conclusions:

1. LG&E/KU are likely to realize net economic benefits from continued membership in the Midwest ISO. For the study period (2005 – 2010), the cumulative net benefits accruing to LG&E/KU are estimated to be approximately $95 million.
2. The authority of the Kentucky Public Service Commission to set rates for end-use customers is not, in any way, diminished by establishing a centralized, security constrained economic dispatch process for the Midwest ISO footprint of operations.
3. In comparison to current practices, the use of locational marginal pricing ("LMP") to re-dispatch generation facilities to solve transmission constraints creates economic gains. Additionally, the application of centralized security constrained dispatch over a wider region leads to more efficient use of generation and transmission resources.

DISCUSSION OF BENEFIT COST ANALYSIS

Q. What approach did you take to evaluate what the likely net economic effects to LG&E and KU from continued Midwest ISO membership would be?

A. The analysis is based on comparing the costs and benefits under the two most likely scenarios. Under the status quo scenario, LG&E/KU would remain a member of the Midwest ISO. In this case, the Midwest ISO would maintain a degree of functional control over the LG&E/KU transmission system and would, as of December 1, 2004, be responsible for the management of congestion through a centralized security constrained dispatch process applied to real-time power flows in a non-discriminatory manner across the entire Midwest ISO footprint. Under the stand-alone scenario, LG&E/KU could provide notice as required by the Midwest ISO Transmission Owners Agreement, seek required regulatory approvals from this Commission and the Federal Energy Regulatory Commission ("FERC"), and, subject to whatever conditions those bodies may attach, exercise their option to withdraw from the Midwest ISO to operate as a stand-alone provider of open access transmission service. It is worth noting that under this scenario, the Midwest ISO dispatch process would treat Kentucky as a "market" to "non-market" seam and — to the extent that generation in Kentucky causes congestion in Midwest ISO — would use physical re-dispatch procedures that may lead to economically suboptimal outcomes for Kentucky. Thus, my testimony presents a comparison of alternatives. Specifically, it compares the anticipated economic benefits and costs to LG&E/KU retail ratepayers of the Midwest ISO providing centralized security constrained economic dispatch services with the expected economic benefits and costs of LG&E/KU attempting to operate their system on a stand-alone basis outside of the Midwest ISO.

Q. How does the fact that LG&E/KU have some of the lowest rates in the nation affect the approach to evaluating the benefits and costs of Midwest ISO membership?

A. The fact that LG&E/KU have access to inexpensive resources affects their economic opportunities to trade in regional energy markets. These effects were taken into consideration in modeling the economic benefits and costs of continued participation in the Midwest ISO. Importantly, the Kentucky Public Service Commission sets retail rates on a cost of service basis. The benefit cost analysis is based on the continuation of cost of service regulation and reflects the obligation for LG&E/KU to use their lowest cost generation to serve native load. While the Companies' operating costs affect the results, whether LG&E/KU was a low cost or a high cost system does not change the approach for conducting such an analysis.

Q. Have you considered alternatives other than the Midwest ISO or stand alone?

A. The Commission asked LG&E/KU to evaluate joining a southern RTO. LG&E/KU evaluated and dismissed the options of joining the SeTrans RTO[1] and forming a separate Kentucky only RTO on grounds of lack of electric system integration and potentially higher costs. I agree that these alternatives appear less attractive than either continued Midwest ISO membership or operating as a stand-alone system. Thus, the essential question is whether the benefits of the LG&E/KU transmission system being included in the Midwest ISO outweighs the net cost of LG&E/KU's continued participation in the Midwest ISO when compared to the alternative scenario of LG&E/KU operating its transmission system on a stand-alone basis.

Q. Why do the estimated benefits arise from continued membership in the Midwest ISO?

A. As shown in the detailed analysis presented in Exhibit RRM-1, the benefits arise from primarily two sources. First, should LG&E/KU choose to withdraw from the Midwest ISO, the current cost of exiting would be approximately $38.2 million (assuming a withdrawal effective as of December 31, 2004). Second, continued membership after the implementation of centralized security constrained economic dispatch and the resulting day-ahead and real-time energy markets yields yearly ongoing net benefits of approximately $12 million per year.

Q. What are the significant components of this result?

A. The ongoing net benefits are predicated largely on the following six categories of benefits (including cost savings or operating efficiencies) and costs:

1. By continuing its membership in the Midwest ISO, LG&E/KU will receive transmission revenues from Schedules 1, 7, 8 and 14 of the Midwest ISO OATT.

[1] The development of SeTrans was halted by the proponents in December 2003.

These revenues are expected to be approximately $21.8 million. While a number of factors may influence this value, the analysis assumes a continuation of the revenues received in the past 12 months.[2]

2. As a stand-alone entity, LG&E/KU would receive from Schedules 1, 7, and 8 of their own tariff approximately $9.1 million annually. The analysis is based on the most recent available sales information and reflects the impacts of LG&E as a stand-alone entity being surrounded by larger interconnected markets.

3. By retaining its membership in the Midwest ISO, LG&E/KU would be subject to approximately $13.4 million in average annual Midwest ISO administrative fees (*i.e.,* Schedule 10, 16, and 17 fees) during the study period.

4. One result of implementing centralized security constrained economic dispatch across the Midwest ISO footprint will be the creation of a sizeable wholesale electricity spot market. In addition to establishing transparent spot prices, this market is anticipated to allow LG&E/KU to increase the volume of their off system power sales. As compared to the stand-alone case, it is anticipated that LG&E/KU will realize approximately $8.3 million in additional annual benefits from being part of a large regional wholesale electricity market.[3]

5. Relative to the stand-alone case, centralized dispatch based on locational marginal prices across the Midwest ISO footprint will reduce the costs associated with managing transmission constraints. It is anticipated that these efficiencies will yield at least $3.6 million in annual benefits to LG&E/KU.

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[2] Events that would serve to reduce this amount would be the elimination of the through and out rate between the Midwest ISO and PJM as well as a reduction in the quantity of point-to-point transmission service sold for transactions occurring either in or within the Midwest ISO footprint. However, the current practice of discounting point-to-point service need not be continued and this would potentially increase revenues from transmission service. On balance, the assumption of using the past 12 months as a guide to the future is warranted given the degree of uncertainty.

[3] The counterfactual to continued membership (*i.e.*, stand-alone operation) assumes that LG&E/KU off system sales would continue at 2002 levels.

6. Our analysis anticipates that LG&E/KU will receive approximately $2 million annually in revenues from the sale of residual financial transmission rights. This is the same value assumed by LG&E/KU in their analysis.

Q. What conclusions can be drawn from these results?

A. The results of any benefit cost analysis are best viewed as indicative rather than precise estimates. Nonetheless, our analysis suggests that LG&E/KU will be economically better off on an annual basis by retaining their membership in the Midwest ISO. Furthermore, this conclusion is not based on a number of significant less quantifiable longer term benefits, such as the likely improvement in investment decisions or any benefits resulting from increased or improved demand-side involvement.

DISCUSSION ON MARKET DESIGN

Q. What is prompting the Midwest ISO to develop energy markets?

A. The development of energy markets is the logical outcome for efficient coordination of non-discriminatory Open Access Transmission Service. In fact, energy markets are a byproduct arising from centralized security constrained economic dispatch. The prime objective is to achieve reliable, efficient, transparent, and replicable system dispatch; and the proven way to achieve this is through the use of locational marginal pricing, which necessarily leads to the creation of a real-time or spot market for electricity.

Currently, the Midwest ISO, in its role as security coordinator, does not dispatch the system. Moreover, the existing method for dispatching used by the individual control areas, as well as by the Midwest ISO for security coordination, relies on estimating Available Flowgate Capacity ("AFC"), Reservations, Schedules, and curtailments of transmission service under Transmission Loading Relief ("TLR") procedures — that, in essence, physically rations transmission capacity based on priorities related to firmness and length of service. Like all physical rationing mechanisms, this is a blunt and inefficient mechanism that contains inherent inefficiencies, distorts market outcomes, and reduces consumer welfare when compared to a market based system.[4] As a result, in order to achieve reliable and efficient real-time coordination of power flows, the Midwest ISO is implementing an LMP-based dispatch process. The result of this process will be real-time and day-ahead energy markets as a means of efficiently allocating the transfer capabilities of the transmission system. By creating bid based markets and allowing for different prices at different locations on the transmission system to be transparent, the Midwest ISO's energy markets will ensure that resources will be more optimally dispatched consistent with efficient and reliable use of the transmission system.

Q. What is the design intent for the Midwest ISO's energy markets?

A. The intent is to achieve the economic benefits of regionally coordinated security constrained unit commitment and dispatch and transparent pricing within the context of non-discriminatory open transmission access. The ability to adjust the bids and offers accepted in real-time also provides reliability coordinators the ability to more precisely manage the system to ensure optimum asset utilization consistent with reliability.

Additionally, the day-ahead and FTR markets will provide market participants with the ability to more efficiently commit capacity and manage economic risks by hedging their market positions against changes in real-time prices.

Q. How will the Midwest ISO energy markets be able to achieve the benefits of coordinated economic unit commitment and dispatch given that the Midwest ISO is not a single control area?

A. The Midwest ISO is coordinating reliability and monitoring the capabilities of the transmission system on a region-wide basis. The Midwest ISO does not need to be a single control area to operate coordinated energy markets that provide its members the benefits of coordinated economic unit commitment and dispatch. The real-time and day-ahead energy markets will function as coordinated regional markets with location-specific ("nodal")

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4 For example, in one instance in 1999, it was necessary to physically curtail over 1,800 MW of power in order to relieve 50 MW on a constrained line.

prices for generation and load. Bids and offers will be accepted on an economic, security constrained basis reflecting continuous monitoring and estimation of power flows throughout the regional transmission system. Moreover, the Midwest ISO markets will be coordinated with comparable adjacent markets in the PJM region.

Q. Does this mean that all suppliers and load serving entities will make price bids in the real-time and day-ahead markets?

A. Definitely not. It is not anticipated that all resources will submit price bids. And, it is not necessary that all resources provide price schedules to achieve the economic benefits of coordinated economic unit commitment and dispatch. Resources for which there is any foreseeable possibility that they could end up economically on the margin will want to submit price bids because they run the risk of operating at a loss — operating generation that costs more to run than the price at which the supplier could purchase equivalent power in the market to cover its supply obligations. If the supplier is a regulated utility, a pattern of unit operations that is uneconomic in comparison to market prices could result in regulators finding that the utility had incurred excessive costs.

Q. What is congestion management?

A. Congestion management is the process of managing competing uses of the transmission system so as to optimize economic outcomes while keeping power flows within operating security limits. This complex process is central to the safe and efficient real-time operation of the transmission system.

Q. Why is congestion management a significant issue in electric transmission?

A. The transmission system in the United States cannot accommodate all requests for transmission service. And, although there are cost effective improvements that could and should be made, transmission capacity should not be built to accommodate all requests. In many instances, managing congestion by re-dispatching resources or reconfiguring transmission is more cost effective than building new transmission capacity.

Q. Why is congestion management a complex process?

The electric power system has unique characteristics that increase the complexity of congestion management. First, power flows change instantaneously. Following the laws of physics, when load, generation, or transmission facilities change, power flows immediately redistribute themselves along the paths of least impedance. Second, within the short time frames that are critical for managing such flows, the transmission system in large part lacks the capability to operate as a switched network. Thus, unlike a telephone call that can be rerouted when a line goes out of service, power system operators have limited direct control about where power will flow when a line or transformer fails.

Third, a single transaction from point A to point B produces a distribution of power flows that can affect transmission paths across a broad region of the grid. The changing overall pattern of generation, load, and transmission facilities in service determines which paths will be impacted. And, in some circumstances, a power transfer in one part of the grid can produce a disproportionate impact on the ability to move power in a geographically distant portion of the system. The transmission capacity of LG&E/KU facilities is impacted by power flows that loop in and out of its system due to transactions between and within other control areas. While it remains interconnected, LG&E/KU transmission cannot be reliably operated as if it were an entirely separate entity. Operators must be able to observe and take into consideration what is occurring outside LG&E/KU's borders.

Fourth, to ensure reliability, the transmission system is operated on a first contingency basis. That means the security limits on the use of specific LG&E/KU transmission lines must be based not only on the physical capabilities of each LG&E/KU line, but on how the flows over that line would change in the event of the failure of other transmission facilities that may be owned and operated by other companies. Thus, the Midwest ISO reliability coordinators rely on monitoring and estimating flows both within and outside the LG&E/KU system to determine whether specific flows can be accommodated on LG&E/KU facilities without placing the system at risk. Finally, changing the location at which power is generated is the primary mechanism used to manage power flows within security limits. Thus, efficiency of congestion management is a direct function of the scope and efficiency with which generation can be re-dispatched to accommodate transmission constraints. By facilitating the economic re-dispatch of generation in response to transmission constraints on a region-wide — not just a local — basis, the Midwest ISO energy markets are expected to significantly reduce the costs of congestion management.

Q. What capabilities would LG&E/KU have to acquire to manage congestion as a stand-alone transmission operator?

A. The Companies have indicated that they will operate their transmission system "in accordance with requirements specified in applicable ECAR documents and the NERC Operating Manual." Applicable ECAR and NERC standards would require LG&E/KU to acquire the capability to meet first contingency reliability criteria — that is, to maintain reliable system operation in the event of an outage of any transmission line, transformer, generator, or other facility within or outside their system that could change power flows on LG&E/KU facilities. To do so, LG&E/KU would have to enter into coordination agreements with other entities to obtain needed data and develop additional capabilities to estimate transmission flows occurring outside their system.

Additionally, it would be very costly for LG&E/KU to duplicate the state estimation capabilities that the Midwest ISO has developed that enable the Midwest ISO to continuously track power flows on monitored facilities and estimate power flows on non-monitored facilities that may affect the available transfer capabilities of LG&E/KU transmission. LG&E/KU do not have comparable capabilities today. The lack of comparable capabilities will limit LG&E/KU's ability to fully utilize its transmission assets consistent with maintaining system reliability.

Finally, the Midwest ISO currently administers a reservation and scheduling system for LG&E/KU and other Midwest ISO transmission owners. The Midwest ISO tariff administration has enabled market participants to rely on a single OASIS ("Open Access

Same-Time Information System") site and a centralized tariff administration organization to determine service availability and to reserve and schedule transmission service throughout the region. If LG&E/KU withdraw from the Midwest ISO, LG&E/KU would have to reestablish its own tariff administration organization.

Q. How would LG&E/KU's capability to manage congestion as a stand-alone system compare to the Midwest ISO's current congestion management capabilities?

A. The capabilities that LG&E/KU realistically might be expected to develop as a stand-alone system would be based on a smaller scope with less precise and less frequent analysis, as well as incomplete information. As a result, in operating their transmission system on a stand-alone basis, it will be difficult for LG&E/KU to efficiently utilize the full capabilities of their transmission assets consistent with maintaining system reliability.

Q. What procedures would LG&E/KU utilize to manage congestion?

A. LG&E/KU would rely on a system of rationing the use of physical rights for allocating the use of scarce transmission capacity. Specifically, the companies have stated that they would use North American Electric Reliability Council ("NERC") TLR procedures to manage system overloads.

Q. How would the use of this approach affect LG&E/KU's ability to efficiently manage transmission congestion?

A. With the best of capabilities, it is virtually impossible to fully and efficiently utilize transmission assets consistent with maintaining reliability applying such a system of physical transmission rights. Inherently, TLRs are both imprecise — meaning that they result in some available capacity being underutilized — and economically inefficient — meaning that least cost re-dispatch is not necessarily achieved.

Q. What are the NERC TLR procedures?

A. NERC has established procedures to curtail transmission service over constrained facilities when necessary to reduce power flows to remain within post-contingency operating security limits and to reallocate available transfer capability curtailing certain transactions to allow high priority transmission service to be provided. These procedures ration scarce transfer capabilities and do so without direct regard for the value to customers of the services being curtailed.

When necessary to maintain power flows over a heavily used transmission facility within security limits, NERC TLR procedures call on Reliability Coordinators to place a hold on new and curtail, as needed, non-firm, firm point-to-point, and network integration transmission service, including service for native load. Specific transactions also are curtailed to reallocate capacity to support higher priority transactions. Non-firm transactions are curtailed prior to firm service. And, the procedures establish priorities among transactions based on the type and duration of service transmission customers have reserved.

Curtailments are applied on a non-discriminatory basis to all service of a selected priority that has an impact on the constrained facility exceeding the curtailment threshold. Transactions with de minimis impact on the flowgate are not curtailed. However, transactions for which even a small percentage of the power, *e.g.,* greater than 5%, is estimated to flow over the constrained facility will be curtailed on a pro rata basis with other transactions having a comparable priority. Under NERC procedures and the FERC's *pro forma* Open Access Transmission Tariff, firm point-to-point and network integration service from designated resources, including network service for native load customers, have the same service priority and are curtailed on a pro-rata basis.

Q. **Why does the TLR system inherently result in transmission capacity being underutilized?**

A. Reliance on TLRs for congestion management inherently leaves transmission capacity under utilized because the TLR approach relies on imprecise estimates and cannot accurately reflect system interactions.

Under NERC procedures, the impact of control area-to-control area transactions and control area generators on constrained facilities is estimated using power flow distribution factors. The estimated distribution factors reflect reported control area-to-control area interchange schedules and reported transmission facility outages. However, power flows estimated using NERC procedures and data do not directly correspond to actual power flows.

Moreover, TLRs are issued to curtail specific transmission transactions. When a transaction is curtailed, the control areas affected re-dispatch generation, curtail load, or reconfigure their systems to comply. Each of these actions takes time and occurs within constantly changing patterns of load, generation, and power flows. Because each change in dispatch, load levels, or system configuration will have power flow impacts and each of the parties to the curtailed transaction is responding individually against a backdrop of changing power flows, the simultaneous impact on the constrained flowgate of the responses to a TLR is difficult to predict with precision.

As a result, it is not possible for reliability coordinators to use TLRs to maintain power flows at post-contingency limits on a sustained basis. Consistent with the responsibility of reliability coordinators to avoid operating system limit violations, this frequently means that some amount of transfer capability goes unutilized during TLR events.

Q. Have you quantified the impact of this effect?

A. Yes. We have analyzed the Midwest ISO's experience during 28 TLR events in the LG&E/KU system from July through October 2003. These events comprise those TLRs for which the Midwest ISO had recorded power flows over the constrained flowgate during the sample period. We determined the amount of unused capacity on these flowgates during TLRs based on the actual and post-contingency power flows recorded at 30 second intervals in the Midwest ISO's flowgate monitoring tool. This unused capacity was then averaged over the total time period during the TLR for which data was available. We found that on average 9.31% of the (post-contingency) flowgate capacity was unused during these TLR events.

Q. Could LG&E/KU as a stand-alone transmission operator possibly do any better job in matching power flows to operating security limits using a TLR process?

A. It is doubtful and certainly not as cost effectively. In order to effectively coordinate real-time power flows, the Midwest ISO will have access to better information and will have superior tools. Consistent with our Transmission Owners Agreement, the Midwest ISO seeks to maximize transmission revenues for its member transmission owners by optimizing asset utilization consistent with reliable system operations.

Q. Why would LG&E/KU's proposed approach to congestion management be economically inefficient?

A. It is economically inefficient for two reasons. First, NERC TLR procedures can disproportionately impact transactions that have a limited impact on the constrained flowgate. Second, LG&E/KU will have to curtail transmission service without regard for its economic value. It is important to note that the NERC TLR procedures were not developed to necessarily minimize the cost of re-dispatch.

Q. Please explain how NERC procedures can affect transmission transactions.

A. Under NERC TLR procedures, when a curtailment is needed, all transactions in the selected service priority that impact the constrained flowgate by more than the minimum curtailment threshold are cut on a pro-rata basis. Operators are not able to curtail only that portion of the power flow from a given transaction that is affecting the constrained flowgate. If only a small portion of the energy for a given transaction is passing through the constrained flowgate, the curtailment to protect the constrained flowgate can have a much larger impact on the parties to the constrained transaction.

In the absence of a market, it is not possible to determine the economic impact of curtailing any particular transaction. However, it is not difficult to imagine cases in which the costs of implementing such a TLR greatly exceed the cost of a comparatively small re-dispatch that could provide the same reduction in flows over the constrained flowgate. Despite the potential advantages of re-dispatch, "the TLR Procedure follows the FERC's *pro forma* tariff that Transmission Providers are not obligated to re-dispatch their own resources to maintain Transactions using Firm Point-to-Point Transmission Service before they are curtailed on a pro-rata basis with transmission use for Network Integration Transmission Service and Native Load." (NERC, *Operating Manual, Appendix 9C1* (October 8, 2002).)

Q. Why do the TLR procedures that LG&E/KU proposes to use as a stand-alone transmission provider not take into consideration economic value?

A. No bids or prices are available to the transmission operator in making TLR decisions. The economic impacts of curtailing particular transactions simply do not come into play. Thus, a short-term transaction that may be critical to lowering costs or avoiding the exercise of market power in a peak price period may be curtailed before a longer term but lower value transaction.

Q. Are there other ways in which a physical rights system of congestion management leads to the underutilization of transmission capacity?

A. Yes. Transmission Reserve Margins ("TRM") set aside transfer capability against which transactions are not scheduled to provide a reasonable level of assurance that the inter-connected transmission network will be secure and reliable. TRM accounts for the inherent uncertainty in system conditions, the effects of that uncertainty on available capacity calculations, and the need for operating flexibility to ensure reliable system operations as conditions change. TRM levels limit available capacity on some LG&E/KU interties even for purposes of scheduling next hour non-firm transmission service.

Q. Are there any other factors that will affect LG&E/KU'S ability to effectively utilize transmission capacity if operated as a stand-alone system?

A. Yes. The capacity of LG&E/KU flowgates is affected by power flows outside of LG&E/KU. Consider, for example, LG&E/KU flowgate number 2198, the Blue Lick 345 kV to 161 kV transformer as limited by the contingency for interruption of flows on the AEP Baker to Bradford 765 kV line. In this case, the power flows that can be permitted over this LG&E flowgate are limited by the level to which flows would surge in the event of an outage on AEP's 765 kV Baker to Bradford transmission line. Therefore, predicting the power transfers that can be accommodated by LG&E/KU for the next day or hour depends on being able to forecast power flows on AEP's transmission line. The information needed to accurately forecast these flows is commercially sensitive for AEP.

The Midwest ISO has observed circumstances in which the best forecast using the information AEP has made available is that no more capacity will be available on this LG&E/KU flowgate, but after the fact analysis of the same period indicates that significant additional capacity could have been made available given an effective ability to manage congestion in real time. We conducted an after the fact analysis of real time 30 second power flow data covering 511 hours during the period from September 1 through November 15, 2003, during which the best available prediction was that there would be no next-hour non-firm capacity available on flowgate 2198. During those hours, on average, 23% of that flowgate's total capacity would have been available.

Q. Are there any other factors that would affect LG&E/KU'S ability to optimize use of their transmission assets as a stand-alone transmission operator?

A. Yes. When security constraints require changes in generation dispatch, as a stand-alone system, LG&E/KU will tend to incur higher re-dispatch costs than they would as part of the Midwest ISO. First, LG&E/KU is a relatively small system and its options for re-dispatching generation to accommodate transmission constraints will be more limited as a stand-alone system than as part of the Midwest ISO energy markets. Second, LG&E/KU will have to implement coordination agreements with neighboring systems to be able to observe flows in adjacent systems and avoid having to bear the full economic costs of re-dispatching to accommodate power flows that loop in and out of the LG&E/KU transmission system from neighboring markets. It is worth noting that LG&E/KU's position in the grid makes it vulnerable to loop flows that could significantly increase its costs.

Third, the decisions utilities make to commit generating units to operate and ramp up or down the operations of units that are in service are to some degree suboptimal because of unavoidable errors in short-term load forecasts. When forecasting, unit commitment, and dispatch are performed for larger systems, there are portfolio effects. In a larger system, some forecasting errors cancel out, and at any point in time there is likely to be a more diverse range of generators whose output can be adjusted to accommodate an unanticipated increase or shortfall in load. The cost of re-dispatch to address forecasting error is likely to be higher for LG&E/KU as a stand-alone system.

Q. How will the inability to fully utilize transmission assets using the physical approach to congestion management impact LG&E/KU retail ratepayers.

A. LG&E/KU will be unable to optimally commit and dispatch their generating units. Additionally, there will be opportunity costs from not being able to identify and complete in a timely manner the optimum mix of import and export transactions. This will increase the cost to serve native load and reduce LG&E/KU off-system sales and profits.

Q. Would you please summarize how the development of the Midwest ISO real-time energy markets will affect the utilization of constrained transmission capacity?

A. The real-time energy market is a derivative of security constrained economic dispatch on a regional basis. Bids and offers will be accepted based on real-time actual and post-contingency power flows. This will allow the Midwest ISO to match power flows over constrained flowgates to post-contingency limits. The Midwest ISO will be able to manage overload conditions by precisely managing power flows using efficient region-wide re-dispatch. In other regions with real-time markets, TRM has been eliminated. We do not anticipate continuing to have short-term TRM in the real-time market. The real-time market will permit full utilization of the capacity available in real time on the Midwest ISO flow-gates. Moreover, the real-time market should supercede most of the reliance on physical transmission reservations and related AFC postings by load serving entities within the Midwest ISO footprint.

Q. What is the Midwest ISO doing to improve forecasts of available flowgate capacity prior to the implementation of real-time markets?

A. The Midwest ISO is taking steps to improve forecasts of available flowgate capacity. First, the Midwest ISO has recently implemented an upgrade to the application used to calculate AFC. With this upgrade, AFC calculations will reflect the continuous updates network configuration captured in the Midwest ISO's regional state estimator. This will both improve AFC calculations and enable us to identify conditions under which traditional AFC forecasts may be inaccurate and make appropriate corrections. Second, as an independent Regional Transmission Organization ("RTO") with no commercial interest in market outcomes, the Midwest ISO is negotiating an agreement with AEP to obtain greater access to information needed to project AFC on flowgates impacted by the AEP system.

Q. Would a stand-alone LG&E/KU transmission operator be in a position to make comparable improvements?

A. Possibly, but at a higher cost. It would be very expensive for a stand-alone LG&E/KU operator to duplicate the network topology tracking capabilities of the Midwest ISO's state estimator.

Q. The Midwest ISO energy markets will be based on Locational Marginal Pricing ("LMP"). What is LMP and how do LMP energy markets relate to congestion management?

A. LMP is a means of making transparent the location specific market clearing prices for generation and other resources. When transmission is congested, wholesale generation located adjacent to a load center is more valuable than generation on the other side of a constraint that may find its transmission service curtailed. LMP markets do not create the differences in prices between these different nodes on the grid. LMP makes price differences resulting from existing congestion more transparent to market participants than may occur in a purely bilateral market. By making location-specific prices transparent, LMP energy markets permit resources to be efficiently dispatched to accommodate physical transmission constraints in a least cost manner. LMP energy markets thereby reduce the economic costs of managing congestion.

Q. What other impacts do LMP energy markets have from the perspective of a load serving entity (or supplier) located within the footprint of such a market?

A. A liquid LMP market assures a load serving entity (or supplier) located inside that market that it can consistently purchase (or sell) real-time or day-ahead energy at the best competitive price bid (or offered) with respect to the location of its load (or generation). Additionally, the market greatly reduces not only the transactions costs but also the lost opportunity costs associated with not having found or been able to conclude in a timely manner the optimum set of purchases and sales. This is not true for the load serving entity (or generator) outside the boundary of the LMP market. For that buyer (or seller), purchasing (or selling) at the boundary of the LMP market is only one of numerous alternatives for which it must forecast results and evaluate in comparison to other potential bilateral deals. Thus, the load serving entity (or supplier) outside the boundaries of the LMP market still faces substantial search, negotiation, transaction, settlement, and opportunity costs.

Q. How will LMP pricing affect network transmission service?

A. The differences in LMPs for different nodes on the grid, which will be made transparent by the development of the Midwest ISO energy markets, will also be used in pricing transactions under network transmission service.

Q. What is the purpose of using LMP in the pricing of transmission service?

A. The use of LMP in transmission pricing will make the transaction specific costs of location-to-location power transfers in the Midwest ISO energy markets equal to the marginal economic costs of costs of moving power. As a result, the Midwest ISO energy markets will reduce the cost of moving power across the Midwest ISO footprint to the incremental cost of completing the power transfers. The implementation of the Midwest ISO – PJM Joint and Common Market will extend efficient pricing for power transfers from Manitoba to the East Coast of the United States.

Q. How does this compare to the transmission charges that would be paid on transactions between the Midwest ISO and LG&E/KU if LG&E/KU were a stand-alone transmission operator?

A. If LG&E/KU withdraw from the Midwest ISO, they would no longer be eligible for Midwest ISO network integration service. As a result, a purchase from Midwest ISO to LG&E would incur Midwest ISO point-to-point transmission charges in addition to any LG&E/KU transmission costs. Similarly, under an Open Access Transmission Tariff, power sales from LG&E/KU would have to incur a point-to-point charge to be treated in a non-discriminatory manner to any IPP or third-party transaction and would incur an LG&E/KU charge for point-to-point transmission service to exit the LG&E/KU control area. In the scenario in which LG&E/KU are outside of the Midwest ISO, such point-to-point charges are essential to avoid cross-subsidizing transmission users seeking a "free ride" on transmission investments made by others. However, such point-to-point charges constitute hurdle rates to completing power purchases and sales that are well above the marginal cost of making power transfers. One of the reasons for creating broad regional

LMP transmission pricing is that traditional pricing is a significant barrier to economically efficient power purchases and sales.

Q. What will be the impact of marginal pricing of transmission on LG&E/KU and its native load customers?

A. Pricing specific power transfers on the basis of the marginal cost of completing the transfer will reduce artificial barriers to imports to and exports from LG&E/KU. It will tend to reduce the cost of operating generation and purchasing power to serve native load. And, it will increase opportunities for LG&E/KU to make off-system sales of excess power from its low cost generators.

Q. Kentucky Revised Statute 278.214 specifies that a utility may curtail service to retail loads only after it has interrupted all other customers whose interruption may relieve the emergency. How will the development of the Midwest ISO energy markets address this requirement?

A. The purpose of managing congestion through real-time markets is to replace rationing systems that can ultimately lead to interrupting service to retail customers. In the real-time market, the Midwest ISO will accept generation and voluntary demand-response bids and offers and implement operating procedures to reconfigure transmission facilities to economically re-dispatch resources to relieve constraints and avoid interrupting electric service to end use customers. In an emergency, retail electric service would not be interrupted until all other feasible alternatives had been exhausted.

Q. Please summarize the differences between the congestion management approach that LG&E/KU would utilize as a stand-alone provider of transmission services to managing congestion through the proposed Midwest ISO energy markets?

A. If functional control over LG&E/KU transmission were fully transferred back to the Companies, they would manage congestion through a system of rationing physical "rights" to quantities of transfer capability. This will produce uneconomic results because:

- Physical rights and Transmission Loading Relief procedures when implemented with the best of capabilities are imprecise and inefficient. LG&E/KU capabilities will be in key respects inferior to the Midwest ISO capabilities. As a result, valuable transfer capabilities on heavily used transmission flowgates will be under utilized.
- Without including LG&E/KU transmission in the Midwest ISO LMP market, it will be impossible to efficiently allocate scarce transmission resources to optimize economic outcomes. The priority based rationing system of congestion management that LG&E/KU would implement curtails transmission service without regard for economic value and in some cases would interrupt transactions that have a small impact on a constrained flowgate before implementing a less costly re-dispatch of resources.
- Functioning as a stand-alone system, LG&E/KU will find it more difficult and expensive to re-dispatch resources to address transmission constraints.
- By contrast, real-time LMP markets are widely accepted as the most efficient means to manage congestion in electric power systems.

Retaining the LG&E/KU system within the Midwest ISO energy markets will benefit Kentucky consumers because:

- Security constrained economic dispatch in the real-time market will provide a means to match power flows in real-time to post-contingency security limits.
- The market will re-dispatch resources on a least cost basis to relieve transmission constraints.
- Real-time and day-ahead energy markets also will significantly reduce power transfer and transaction costs for those load serving entities and generators located within the market boundaries.

Q. Does that conclude your testimony?

A. Yes, it does.

VERIFICATION

The answers in the foregoing testimony are true and correct to the best of my knowledge and belief.

Ronald R. McNamara

Ronald R. McNamara

STATE OF OHIO)

COUNTY OF DELAWARE)

Subscribed and sworn to before me by Ronald R. McNamara, on this the 29th day of December, 2003.

NOTARIAL SEAL
STATE OF OHIO

JULIE A. RODGERS
Notary Public - State of Ohio
My Commission Expires Jan 10, 2008

(SEAL)

Julie A. Rodgers

Notary Public

My commission expires: January 10, 2008

Exhibit RRM_1

Benefit – Cost Quantification for Managing LGE / KU Transmission Within MISO or on a Stand Alone Basis

December 29, 2003

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Benefit – Cost Quantification for Managing LGE / KU Transmission Within MISO or on a Stand Alone Basis

1. Overview

To quantify the economic benefits and costs of operating LGE / KU transmission within MISO versus transferring functional control back to LGE / KU to operate as a Stand Alone system, the analysis focused initially on key near-term differences between these two alternatives. The benefits and costs of including the LGE / KU system within MISO centralized security-constrained dispatch and of LGE / KU managing congestion on a stand alone basis using North American Electric Reliability Council (NERC) Transmission Loading Relief (TLR) procedures were considered. The near-term economic impacts that were quantified include:

- More efficient congestion management under MISO real-time economic dispatch than is possible using TLR procedures;
- Opportunities for LGE / KU to optimize off-system sales if the LGE / KU system is within the MISO – PJM Joint and Common Market;
- An updated and accurate assessment of the coverage of congestion costs through the anticipated allocation of Financial Transmission Rights; and
- Transmission revenue implications of leaving MISO to operate as a separate provider of transmission services.

Additionally, MISO Schedule 10, 16, and 17 charges and MISO Exit Fees were updated.

Table RRM_1-1 provides a summary of near term benefits and costs. For purposes of presentation and consistent comparison with the Companies' benefit – cost analysis, this summary accepts the quantification from the Companies' study of several smaller items, including:

- MRMD Staffing, Training, Consulting;
- Miscellaneous MISO Uplift Charges;
- Ancillary Market Cost;
- Net Committee Participation, Contracts;
- Net FERC Attachment O Fees;
- Additional Staffing;
- Systems Related Costs; and
- Lost FTR Revenue.

These items are described in Company Exhibit MJM-1 at pp. 54-56. Acceptance of these items for purposes of comparison does not necessarily imply agreement with the Companies' quantification.

Taking all of these factors into consideration, the 2004 Present Value Net Benefit of LGE / KU remaining in MISO through 2010 was found to be $95 million.

Near-term benefits and costs, however, are only part of the picture. The development of transparent and efficient spot markets will change economic incentives and produce significant intermediate and long-term efficiency benefits. The analysis provides a qualitative summary of these benefits and quantitative indicators of the potential magnitude of two such benefits: facilitation of demand response and incentives to reduce forced outage rates.

The remainder of this report is divided into four sections addressing: quantification of near-term congestion management and market benefits; coverage of congestion costs by Financial Transmission Rights; LGE / KU wholesale transmission revenues; and intermediate to long-term efficiency benefits.

2. Quantification of Near-Term Congestion Management and Net Margin on Off-System Sales Benefits

To quantify congestion management benefits of MISO centralized economic dispatch and the opportunities for LGE / KU to increase their net margins earned on off-system sales in MISO energy markets, detailed chronological production costing and power flow modeling was undertaken for alternative scenarios with LGE / KU transmission operated within MISO and as a separate, stand-alone system. This section describes the methodology utilized, cases modeled, certain underlying analyses, and detailed modeling results.

2.1. Overview of Production Cost and Power Flow Modeling Methodology

The analysis of congestion management and market benefits utilized the PROMOD IV® production costing and power flow model to simulate electric system operations and regional power markets. The model was used to project hourly production costs and location-specific market clearing prices under alternate scenarios. The modeling captured details of power system operations in the Eastern Interconnect, including representations of the operation of 5,000 generating units, 40,000 transmission buses and 50,000 transmission lines. The model calculates and can track location-specific, hourly prices for up to 8,000 specific locations in the transmission grid. The results capture the differences in hourly market clearing prices between the locations of specific generators and loads within the system.

PROMOD IV's unit commitment and dispatch procedures follow a chronological sequence similar to that used in the actual operation of generating units. The unit commitment logic is based on a detailed marginal scheduling algorithm that models generator constraints for minimum runtime and minimum downtime, along with start-up costs, capacity bids and energy bids. This process starts with an initial unit commitment order for the week, and then performs an iterative improvement of the unit commitment schedule for each day of the week, considering the location-specific replacement cost of energy at each generator bus. Checking for violations of minimum runtime and minimum downtime constraints on each unit, the logic looks for alternative commitment decisions that improve the economic performance of the system. Once the unit commitment schedule has been determined, security constrained economic dispatch is performed by loading incremental unit segments in bid order, subject to operational constraints. The unit dispatch procedure simulates detailed hourly chronological dispatch subject to ramp rate limits on maximum hour to hour changes and a Monte Carlo simulation of generating unit outages.

The impacts of the electric grid are incorporated via transmission interface limits (MW), loss factors, and economic limitations ($/MWH). Transmission interface limits are dynamic physical constraints on power flows, leading to differences in location specific market clearing prices. The model calculates losses dynamically, such that Locational Marginal Prices (LMPs) include a marginal loss component. Economic limitations or hurdle rates are used to model transmission tariffs and simulate market inefficiencies. The analysis of transmission reflects the MISO power flow model including the impacts of transmission constraints and loop flows.

2.2. Power Flow and Transmission System Representation

PROMOD IV performs a security-constrained unit commitment and dispatch, meaning that the economic dispatch of generation must be simultaneously feasible given a variety of potential transmission system conditions. Transmission system configurations, capabilities, and power flow distributions were based on the Midwest ISO's power flow case for 2004 peak conditions.

To implement the power flow case in PROMOD IV, each generating unit was mapped to its appropriate transmission bus. The load busses in each control area were identified and the hourly load forecast for the control area was assigned to its specific load busses. PROMOD IV represents the power flow case as a linearized powerflow. Shift factors are calculated to represent the redistribution of power flows associated with changes in generator output or load at specific locations.

The model optimizes the dispatch of the system, subject to a set of transmission constraints that represent the financially significant constraints that might be binding on the system dispatch. These transmission constraints comprise both base flow constraints, representing path based flowgate limits, and contingency constraints, reflecting limits based on the flows that would occur in the event of a failure of one or more other specified transmission elements. Contingency constraints occur where the failure of the secondary element(s) would increase flows over the primary flowgate to levels in excess of its security limit. The resulting economic dispatch will be such that, if any of those specified contingencies were to occur, the powerflow would still be feasible. The list of potentially binding constraints used in this analysis was derived from the flowgate list maintained by the Midwest ISO. This list comprises approximately 720 constraints, including over 300 contingency events.

2.2.1. Use of the 2004 Power Flow Case

To complete the analysis in a timely manner, modeling was based on an existing MISO power flow case for 2004.[1] While separate modeling runs were not performed for multiple years, the congestion management and lost margin benefits based on the 2004 power flow case provide a generally representative and potentially conservative representation of the annual benefits that can be expected during the next 5 to 10 years. Given the few planned major generation additions after 2004 and limited planned improvements in the transfer capacity of key flowgates, congestion management benefits could increase over the period as regional load and power transfers rise. As LGE / KU native load grows, the companies may have less energy available for off-system sales. However, any reductions over time in the volume of off-system sales are likely to be offset by higher per MWh margins as energy markets tighten.

[1] The development, review, and testing of additional power flow cases and updating transmission system characteristics, generator bus assignments, and distribution of loads by bus is a complex process. Given the time available to file testimony in this proceeding, it was not possible to implement power flow cases for additional years.

2.3. Fuel Price Forecasts

The gas and oil fuel price forecasts used in the modeling have been developed using two components. The first component is a general market price forecast based on futures market prices. The second is a locational basis differential, established based on historic price relationships. Coal and nuclear fuel prices were based on plant specific data reported by generation owners and operators.

2.3.1. Natural Gas Price Forecast

The forecasted market price component for natural gas are based on the October 29, 2003 NYMEX forward prices for natural gas at Henry Hub for delivery in each month of 2004.

Locational basis differentials for each state for natural gas were determined by taking the difference between the average delivered price of natural gas in each state over the period January 1999 through December 2002 and the average daily spot price at the Henry Hub for delivery in that same month. The natural gas basis differentials tend to widen in the winter when deliveries on the pipeline system can be capacity constrained. The basis differentials have been set on a monthly basis so as to reflect these seasonal patterns.

The delivered cost data used to calculate basis differentials are the costs reported by utilities for spot and interruptible gas on the Energy Information Administration Form EIA 423. This survey is designed to capture cost data that includes both interstate pipeline and local distribution company transportation charges. These data are aggregated by state and published by EIA in *Electric Power Monthly,* and the underlying data are available in an on-line data base. Beginning in December 2002, the published data no longer distinguish between the cost of spot, interruptible, and contract gas purchases.

In general, state level average natural gas costs were utilized to calculate the natural gas basis differentials. There were two exceptions to the use of state level data. First, for LGE and KU, we used their individual EIA Form 423 responses.[2] Since they provided Form 423 data to us through September 2003, our basis differentials for LGE / KU are calculated over the period January 1999 through September 2003. Second, EIA did not publish any gas fired generation fuel cost data for South Dakota or Tennessee, and data from adjacent states was used to calculate locational basis differentials for these states.

In a small number of instances, EIA gas costs include anomalous data that appear to reflect data entry errors by the submitting company or EIA. Anomalies were investigated by reviewing the disaggregated company Form EIA 423 data. In a few cases, the data entries were judged to very likely reflect some kind of data error, and the state average was recalculated excluding this observation.

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[2] LGE/KU supplied and appears to file Form EIA 423 gas cost reports for the Cane Run and Mill Creek plants. LGE/KU also burns gas at several other plants that are large enough to be covered by Form EIA 423. It appears that the gas cost data reported for Cane Run and Mill Creek actually cover the gas consumed at other LGE/KU units. The basis differentials for the LGE/KU plants other than Cane Run and Mill Creek were calculated using the average of gas costs for the Cane Run and Mill Creek plants.

2.3.2. #2 Fuel Oil Price Forecast

A similar methodology is used to develop forecasted prices for #2 fuel oil. The price forecast component for #2 oil price is the October 29, 2003 NYMEX forward price for #2 oil delivered in New York harbor during each month of 2004.

The state-by-state locational basis differentials relative to the New York Harbor futures market price were calculated using the costs reported by utilities for spot purchases of #2 oil on Form EIA 423. As in the case of natural gas, this survey is designed to capture delivered costs including transportation charges. In general, state level average #2 oil prices were utilized to calculate locational basis differentials.

There were gaps in the Form EIA 423 data for South Dakota and in regions outside of MISO. Data from representative states was used to address these gaps. Additionally, a small number of apparent data reporting errors were identified and excluded from the analysis.

As with natural gas, LGE / KU #2 fuel oil cost data were utilized rather than state level data for the LGE and KU plants. For #2 oil, however, there were many gaps in the monthly costs reported at the plant level, making it impossible to directly calculate basis differentials for each plant in each month. The basis differentials for the LGE / KU plants were therefore estimated using a simple econometric model.

The summer-winter swing in location basis differentials tends to be less for #2 oil than for natural gas, reflecting lower storage costs and the availability of multiple modes of transportation.

2.3.3. Residual Fuel Oil Price Forecast

The residual oil forecast is based on a comparable methodology to that used for natural gas and #2 fuel oil prices. The price forecast component of the residual oil price was based on the October 29, 2003 NYMEX forward price for West Texas Intermediate (delivered to pipeline) during each month of 2004. The futures market price for crude oil is utilized because there is no forward market for residual oil, and residual oil prices are reasonably well linked to crude oil prices. The basis differential for residual oil is calculated in essentially the same manner as for natural gas, using the differential between the delivered residual oil costs reported by utilities on the Form EIA 423 and the spot price of West Texas Intermediate. Basis differentials are applied to the NYMEX forward price for West Texas Intermediate in order to develop forward projections for residual oil prices that reflect both locational price differences and the price difference between crude and residual oil. There are gaps in Form EIA 423 data for residual oil; however, this in large part reflects the lack of residual oil fueled generation in several states.

2.3.4. Coal Price Forecast

Forecasted coal prices and heat content were developed for each plant that burns coal based upon data submitted by the generator to EIA, EPA, and other agencies as well as published utility documents. For LGE / KU, forecasted coal prices were compared to historical data filed by LGE on Form EIA 423.

2.4. Load and Demand Forecasts

Load and demand forecasts represent forecasted control area load and demand. Forecasts were based on the combination of the Form FERC 714 filings, NERC Energy Supply & Demand

(ES&D) data, and NERC regional summer/winter assessments. Area peak and energy forecasts within a NERC sub-region are scaled to match the total sub-region monthly peak and energy forecast provided in the NERC ES&D database. This scaling is done based on the relative peak and energy values provided in the Form FERC 714 forecasts. This preserves the relative forecasted growth rates of different areas within a sub-region while still recognizing the NERC sub-region forecast which has broader acceptance and credibility. Within a month, hourly load shapes are based on the latest 714 data or where available ISO data.

2.5. Generating Unit Data

In general, generating facilities are represented based on plant or unit data for that facility. The primary data sources for generating units include the EIA-411, EIA-412, EIA-423, EIA-767, EIA-860, FERC Form 1, and REA-12. Information filed by owners and operators in response to these surveys or filing requirements also has been used to derive default data for similar new units and generators that may have missing or incomplete filings. Data supplied by generation owners and operators in these filings include generator name, location, summer/winter capacity, primary and secondary fuels, NERC Generating Availability Data Systems (GADS) category, operating and maintenance (O&M) costs, heat rates, projected capacity changes, projected retirement dates, and average monthly hydro energy. Defaults values for forced outage rates, forced outage durations, and scheduled maintenance requirements are taken from GADS. Each unit has been assigned a location at a specific bus in the transmission grid.

Detailed operational data from Continuous Emissions Monitoring System (CEMS) submissions to the U. S. Environmental Protection Agency (EPA) are used to derive multiple capacity states with associated incremental heat rates. Emission production rates for SO_2, NO_x, and CO_2 are taken from documents published by EPA. Forecasted prices for SO_2 and NO_x allowances along with the associated forecast for unit specific emissions reduction technology upgrades are based on *Platts* forecasts.

2.6. Calculation of Locational Marginal Prices

The results of the modeling include the Locational Marginal Price (LMP) of energy at each transmission bus. Mathematically, this LMP is the shadow price for the generation-load balance equality constraint for a specific transmission bus. In layman's terms, it is the cost ($/MWh) that would be incurred to serve a small increment of additional load at that location in the transmission grid. The LMP at the bus depends directly on which generators are "on the margin" in the security-constrained dispatch given their contributions to flows on the transmission flowgates that are at their limit in the dispatch. The LMP reflects the cost impact of transmission congestion and the marginal transmission losses incurred in serving the incremental load at the bus.

For purposes of separately identifying the congestion cost and loss components of LMPs, congestion and loss costs in all LMPs can be expressed relative to a single reference bus. The choice of a reference bus has no impact on the actual LMP at each other bus, but provides a reference point for purposes of separating out and comparing the congestion and loss components of LMPs for specific busses. When separately identifying congestion and loss costs, the analysis uses the Clifty Creek transmission bus as the reference bus. Clifty Creek was selected as being central to the geographic footprint being modeled and near the LGE / KU control area.

2.7. Cases Modeled in the Analysis of Near-Term Congestion Management and Net Margin on Off-System Sales Benefits

The analysis focuses on factors distinguishing the operation of LGE / KU transmission within MISO from the operation of LGE / KU as a stand alone system outside MISO. Although not all of the factors that distinguish centralized dispatch from separate operation under a TLR based system of congestion management could be readily modeled within the time available, key physical limits on the effective use of transmission capacity and financial hurdles to trade were modeled.

To identify congestion management savings from centralized MISO economic dispatch, the cost to serve LGE / KU control area load was modeled for each of the four scenarios described below. Additionally, the scenarios of "LGE / KU Transmission System in MISO" and "Stand Alone LGE / KU Transmission Operations – Combined Effective Physical Limit and Hurdle Rate Effects" were used in determining the net margins on wholesale sales that would be lost if LGE / KU left MISO.

2.7.1. LGE / KU Transmission System in MISO

The LGE / KU in MISO case represents the inclusion of the LGE / KU transmission system in MISO centralized economic dispatch and energy markets.

With LGE / KU transmission being managed as part of MISO, security constrained economic dispatch for MISO's real-time energy market would match power flows on constrained flowgates to the security limits in real time. In this case, PROMOD IV was permitted to optimize economic dispatch consistent with security limits for each transmission constraint.

Load Serving Entities in MISO will be able to purchase power in spot markets from sources within MISO or PJM without having to pay for base transmission service on a transaction-by-transaction basis. Given that cost of transmission, aside from losses and congestion costs that were captured in the model, would not change based on whether a local source was used or power originated at some other point in the MISO – PJM Market, the transmission tariff was not used to set a hurdle rate limiting transactions within the MISO – PJM Market; in this case that includes LGE and KU. Additionally, the day-ahead and real-time energy markets will provide transparent and location-specific pricing for each node within the MISO – PJM market, including all LGE / KU nodes. As a result the transaction costs associated with purchasing or selling spot energy would be minimal. And, no transaction cost hurdle rate was imposed to limit power transfers inside MISO – PJM energy markets.

2.7.2. Stand Alone LGE / KU Transmission Operations – Effective Physical Limits

By managing congestion based on TLR procedures, a stand alone LGE / KU transmission system would not be able to efficiently utilize the full capacity of its transmission assets. To partially capture this effect, we have modeled two effective physical limits on the use of the LGE / KU transmission system under LGE / KU stand alone operations.

First, we analyzed the average amount of transmission capacity available during more than 266 hours in which the use of LGE / KU flowgates were limited by TLR Level 3 or higher procedures from July through October 2003. Given the inherent imprecision of the TLR process, the analysis found that, on average during all TLR periods for which power flow data was available, 9.31% of flowgate capacity was unused. It would be extremely difficult for LGE / KU operating on a stand alone basis using TLRs to manage congestion to do as well or better at matching flows to security limits. In this case, the effectively available capacity of all LGE / KU flowgates was reduced by 9.31%.

Second, on certain interties between LGE / KU and Southern Indiana Gas & Electric (SIGE) utilization of transmission is further limited by non-firm Transmission Reserve Margins (TRMs) of 3.5% on FG 2195 and 4.2% on FG 2500. The capacity effectively available on these two flowgates was further reduced to reflect these non-firm Transmission Reserve Margins. With a real-time energy market, TRMs should no longer be needed.

2.7.3. *Stand Alone LGE / KU Transmission Operations – Hurdle Rates*

In addition to the inherent inefficiencies of managing congestion using TLR procedures, stand alone operations would impose two types of financial barriers to power purchase and sale transactions between LGE / KU and the larger MISO / PJM market.

First, LGE would have to pay for MISO or PJM Point-to-Point transmission service to import power out of the MISO / PJM footprint. The financial burden of having to purchase MISO or PJM transmission service is incremental to any transmission service costs associated with buying or dispatching generation within the LGE / KU control area. Hurdle rates have been set to capture the incremental MISO / PJM tariff costs associated with importing power from these pools in the Stand Alone case. Similarly, when modeling net margins from off-system sales, exports from LGE must be cost-effective for buyers in MISO or PJM at delivered prices that incorporate the additional tariff charges for LGE / KU transmission service. If LGE / KU were part of MISO, buyers elsewhere in MISO or PJM could purchase LGE / KU generation through real-time or day-ahead energy markets and incur no incremental transmission charges, aside from losses and any congestion costs, relative to using local generation.

Second, if its transmission system is outside the MISO market, LGE / KU will face additional search, negotiation, contracting, settlement, and opportunity costs associated with attempting to find the best deal when buying or selling generation. This has been represented with an additional $3/MWh transaction cost component in the hurdle rates on transactions involving parties in different pools, including in this case transactions between LGE / KU and parties in the MISO – PJM Market.

2.7.4. *Stand Alone LGE / KU Transmission Operations – Combined Effective Physical Limit and Hurdle Rate Effects*

As a stand alone transmission operator, LGE / KU could be expected to perform no better than what is reflected in a Stand Alone case which combines the impacts of effective physical limits on the use of the transmission system and financial hurdle rates to trade.

In fact, the model runs that combine these limitations overstate the performance that could be reasonably expected from stand alone operation of the LGE / KU transmission system. This is apparent for two reasons. First, there were several barriers to efficient stand alone operations that could not be modeled in the time available to complete this analysis. These include:

- The distinction between hourly congestion management and real-time redispatch – PROMOD IV is an hourly model;

- The disproportionate impact that TLR events can have on transactions that have a limited impact on constrained flowgates, i.e. if 10% of a transaction impacts a constrained flowgate, 100 MW of scheduled flows may be curtailed to achieve 10 MW of relief on the constrained flowgate;
- The impact of pro rata TLR curtailments of specific transactions without regard for economic value – PROMOD IV may understate these effects by using pool-based redispatch in response to transmission constraints;
- The transfer capacities actually available on some flowgates during hours in which transactions are limited due to a calculation of zero non-firm AFC using standard NERC procedures and limited real-time observability of power flows on other systems that impact AFC calculations;
- Redispatch costs that may be shifted to LGE / KU given the management of seams between LGE / KU and larger neighbors; and
- Reduced capability to offset or respond to the effects of load forecast errors.

Second, modeled LGE / KU sales to parties outside the LGE control area in this case are significantly higher than the levels that LGE / KU was able to achieve in 2002. That LGE / KU actual non-requirements sales did not achieve modeled levels indicates that the model is taking advantage of opportunities not identified or pursued by the Companies' actual operations.[3] By scaling modeled stand alone off-system sales to 2002 non-requirements off-system sales, it was possible to compensate for differences between modeled and actual operational efficiency for purposes of quantifying lost margins on off-system sales under Stand Alone operations. However, it was not feasible to compensate for overstating the efficiency of Stand Alone operations in our modeling for purposes of quantifying the congestion management benefits of MISO centralized dispatch. As modeled, congestion management cost savings from MISO membership could be significantly understated.

2.8. Analysis of TLR Events

The use of NERC TLR procedures to manage congestion on heavily loaded flowgates is inherently imprecise and inefficient. Reliability coordinators seek to fully utilize transmission capacity consistent with preventing violations of security limits. In the absence of centralized economic dispatch, they lack the means to match constantly changing power flows to security limits in real time. In the absence of a precise means to manage flows in a TLR environment, when reliability coordinators curtail or hold transactions to prevent security limit violations, some amount of capacity is left unused. To quantify this effect, MISO analyzed the average amount of transmission capacity available during TLR Level 3 or higher events on the LGE / KU system from July through October 2003. The analysis found that on average during TLR events 9.31% of actual flowgate capacity was unused. Table RRM_1-2 identifies the average unused capacity for each TLR event analyzed.

2.9. Hurdle Rates

If LGE / KU withdraw from MISO, LGE / KU will incur additional costs to purchase from the MISO – PJM market. And, potential purchasers of LGE / KU generation in MISO or PJM will

[3] Modeled sales were based on control area loads. To be consistent, modeled exports were compared to non-requirements Sales for Resale, excluding transactions between LGE and KU.

buy from LGE / KU only when it is economic to do so after payment of non-discriminatory LGE / KU transmission service charges. These financial barriers to trade have been captured in hurdle rates that reflect both the incremental transmission service charges associated with purchasing generation on a different transmission system and the transaction and opportunity costs associated with having to search for the best deal. Table RRM_1-3 presents the hurdle rates that were applied to exports from MISO and PJM to LGE and from LGE to MISO and PJM in the hurdle rate cases.

2.10. Congestion Management Benefits

Including the LGE / KU transmission in the centralized security constrained economic dispatch provided by MISO's real-time energy market represents a more precise and efficient way to manage congestion than implementing NERC TLR procedures on an LGE / KU stand alone basis. Our production costing and power flow analysis quantified the savings in the cost to serve control area loads.[4] The analysis identified the net benefit of LGE / KU being inside MISO compared to stand alone scenarios for effective physical limits, financial hurdle rates, and the combination of physical limits and financial hurdles. Our results indicate that if LGE / KU remains in MISO, more efficient management of congestion will produce savings of at least $3.657 million per year. Actual savings, taking into consideration factors that could not be modeled within the time and model constraints for this analysis, could be significantly higher. The results are summarized in Table RRM_1-4.

2.11. Net Margin on Off-System Sales Benefits

Including LGE / KU within MISO energy markets reduces the costs and physical limitations on LGE / KU making off-system sales. Our analysis found that if the LGE / KU transmission system were included in MISO, LGE / KU could make more than 8.6 million MWh of off-system sales per year to parties outside its control area. This compares to 5.7 million MWh of non-requirements sales to such parties in 2002. Comparing the net margin on off-system sales for the case in which LGE / KU remain in MISO with Stand Alone margins scaled to actual 2002 non-requirements sales volumes, MISO participation increases LGE / KU net margins on off-system sales by $8.348 million per year. This calculation is presented in Table RRM_1-5.

To calculate the economic benefit to LGE / KU associated with making additional off-system sales, we modeled net margins on off-system sales using PROMOD IV. The net margin was calculated as the difference between export revenues at LGE / KU generator bus Locational Marginal Prices and the net cost of generating power for export. The net cost of generation for exports represents the difference in total production costs when dispatching the system to serve a combination of exports and sales to control area customers and the total production costs to serve control area load alone. The LGE / KU net margin on off-system sales, assuming LGE / KU remains within MISO, was projected to be $21.7 million per year.

For the case in which LGE / KU remains in MISO, the projected volume of economic off-system sales is more than the expected off-system sales in the LGE / KU Stand Alone cases and 50% above comparable actual sales for 2002. To calculate net lost margin, projected margins in the combined physical – financial Stand Alone model run were scaled back based on the ratio of

[4] The congestion management benefits of MISO markets for off-system sales are included in the Net Margin from Off-System Sales benefit quantification.

modeled to actual 2002 non-requirements sales volumes. This was appropriate given that it was not possible to fully capture in the Stand Alone model runs the barriers to efficient use of LGE / KU transmission assets under stand alone operations.

Non-requirements sales for 2002 are likely to be representative of near-term exports because, unlike earlier years, 2002 reflects the impacts of the recent capacity additions and tighter credit requirements. In fact, 2002 volumes may represent an optimistic projection of the Stand Alone off-system sales. If LGE / KU withdraws from MISO, off-system sales could decline relative to 2002 due to higher hurdle rates on transactions into MISO and LGE / KU's lack of full participation in the MISO – PJM market.

The Stand Alone model run provides a reasonable basis for projecting per MWh margins on off-system sales given that LGE / KU would be selling in or adjacent to a large transparent spot market.

3. Financial Transmission Rights Coverage for Congestion Costs

There are several transmission facilities within and at the borders of LGE / KU that are heavily utilized such that often no further non-firm flowgate capacity is available or TLR procedures must be invoked to avoid violating security limits. When the effectively available transfer capacity of one or more flowgates is fully utilized, the limits on power transfers may give rise to congestion costs. Congestion costs will be reflected in differences in power prices at different locations on the grid. Such costs exist today, but are not always readily quantifiable due to the lack of a transparent spot market. MISO energy markets do not create congestion costs. They make congestion costs transparent. By making congestion costs transparent and using location specific price bids and offers in centralized security-constrained dispatch, MISO energy markets will reduce congestion costs. Our analysis reflects this reduction in a reduced cost to serve LGE / KU control area loads. See: Section 2.10 above.

Congestion is addressed in different ways under systems of physical or financial transmission rights. Physical rights are not absolute, but subject to curtailment. Physical rights consist of a set of priorities that determine the order in which transactions will be curtailed. When a physical right is curtailed no financial compensation is available for the economic consequences of the system's inability to honor the service reservation. By contrast, a system of financial transmission rights is designed to provide compensation when not all economic power transfers can be accommodated. A financial right assures the holder of a net price that reflects the price of power at the designated source location.

MISO will allocate requested Financial Transmission Rights to holders of existing physical rights. Taken as a whole, the allocations will represent a simultaneously feasible set of power flows.[5] Allocations are being developed to place LGE / KU and other MISO members in a position that is financially equivalent to that resulting from their existing physical transmission rights. The development of allocations is an on-going process based on modeling of the maximum feasible allocations. During the summer and fall of 2003, several preliminary studies were released to members for comment in an effort to improve the quality of the studies and identify ways in which the number and value of FTRs allocated could be increased, consistent with

[5] Limiting allocations to a set of FTRs that is simultaneously feasible avoids additional uplift charges to compensate FTR holders for congestion costs.

meeting the simultaneous feasibility test. As these preliminary studies were released, MISO identified and discussed with LGE / KU modeling issues that in some preliminary studies led to understating the FTRs that could be allocated to LGE / KU. Subsequent studies have improved the representation of these issues and increased the number of FTRs that can be allocated to LGE / KU.

LGE / KU's benefit – cost analysis assumes that in MISO LGE / KU will incur $2 million per year in LMP congestion costs that would not be covered by Financial Transmission Rights (FTRs). (Exhibit MJM – 1.) The Companies' analysis is flawed in two major respects.

First, it is based on earlier study in which the modeling issues that limited FTR allocations to LGE / KU had not yet been resolved. LGE / KU used this understated allocation of FTRs to identify 788 peak hours and the MWh of load in those hours for which congestion costs might not be fully hedged. The Companies' analysis assumes that LGE / KU would be entitled to an allocation of only 4,686 MW of FTRs. The current FTR study indicates that LGE / KU would be entitled to an allocation of 7,035 MW of FTRs.

Second, for Kentucky ratepayers, the relevant costs are LGE / KU load zone congestion costs in excess of congestion costs at the grid locations where generation is being dispatched to serve LGE / KU load in the hours in which FTR coverage may be incomplete. Locational prices vary from hour-to-hour. In some hours, LMP prices in LGE / KU load centers may be lower than prices at some of the Companies' major generation stations. Without comparing generation to load zone prices for specific hours, it is not possible to determine the financial impact of a gap in FTR coverage. There is no indication that the Companies analyzed LGE / KU generation to load congestion costs for the specific hours for which full FTR coverage might not be available.

When asked to do so in discovery, the Companies failed to fully describe the basis of their congestion cost estimate. The Companies appear to have started with an estimate of annual congestion costs assuming that no FTRs were available. Then, in response to a MISO discovery request, Company witness Morey states that, "The Companies determined that the congestion cost exposure for those hours [in which load exceeded the proposed FTR allocation] would amount to between $1.5 million to $2.0 million per year, given the Congestion Cost Analysis provided by MISO. The assumption was made that the cost would average $2.0 million per year." (Response to MISO Supplemental Data Request No. 6) The "MISO Congestion Cost Analysis" provided with the response does not address congestion costs in specific hours. No further elaboration was provided on the development of the $1.5 to $2.0 million per year figure.

We analyzed the FTR allocations likely to be available to LGE / KU based on current studies. Our conclusion is that the available allocations will meet the objective of placing LGE / KU in a position that is financially equivalent to the protections provided by existing physical rights. We found that congestion costs to serve control area loads that would not be covered by FTR allocations equal $73 per year.

We conducted the analysis based on the December 19, 2003 MISO FTR allocation study. Based on this study, LGE would be entitled to an allocation of 7,035 MW or 89.1% of its total physical reservations.[6] We examined each individual allocation and identified 6617.35 MW of FTRs as-

[6] Given that physical rights are not absolute, an allocation of FTRs equal to less than 100% of reserved capacity may be financially equivalent to the protection provided by such physical rights.

sociated with serving native load customers. Using our chronological production cost model, we identified 81 hours in which control area loads exceeded the volume of available FTRs, the MW by which load exceeded the FTR allocation for native load, and the difference between average LGE / KU generation bus and load zone congestion costs in each hour.[7] The results are summarized in Table RRM_1-6.

4. LGE / KU Transmission Revenues

To complete the analysis of the short-term economic benefits and costs of MISO membership, we examined the transmission revenues that LGE / KU could receive as a result of Point-to-Point transmission service remaining within MISO and on a stand alone basis.[8] Revenues from point-to-point service are an indicator of transmission revenue requirements that may be recovered from parties other than LGE / KU retail ratepayers.

As a member of MISO, LGE / KU benefits from the distribution according to specific allocation formulas of MISO Schedule 1 (Scheduling, System Control, and Dispatch), Schedule 7 (Firm Point-to-Point Service), Schedule 8 (Non-firm Point-to-Point Service) and Schedule 14 (Through and Out Rate) revenues. Over the last 12 months, LGE / KU distributions of Schedule 1, 7, 8, and 14 revenues total $21.8 million. See: Table RRM_1-7.

These actual receipts are the best available representation of transmission revenues that LGE / KU will continue to receive as a MISO member. Transmission revenues may change from historical levels. The elimination of through and out rates to PJM, all else being equal, would cut out a fraction of Point-to-Point transmission revenues. And, the volume of Point-to-Point service within MISO might decline as the market provides other alternatives. On the other hand, MISO currently discounts Point-to-Point transmission rates to facilitate transactions within its footprint and take into consideration the transfer prices that the market will bear. To the extent the market provides other alternatives for transactions within the MISO footprint, MISO can be expected to reconsider and potentially eliminate discounting of Schedule 7, 8, and 14 rates. Under the Transmission Owners' Agreement, MISO is required to maximize (up to the cost of providing service) transmission revenues for its transmission owning members. MISO discounts from full costs when doing so increases transmission revenues. In the future, price margins on exports to regions in which prices are set by comparatively high priced gas fired generation are likely to have a relatively greater influence on whether MISO discounts transmission rates. Taking all of these factors into consideration, actual Schedule 1, 7, 8, and 14 revenue distributions are a reasonable indicator of transmission revenues that LGE / KU could receive remaining within MISO. While there is a degree of uncertainty about future transmission revenues, we are confident that

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[7] Congestion costs for each location in the transmission system are calculated with respect to a single reference bus (Clifty Creek). It is therefore necessary to look at the difference in congestion costs between generator and load locations.

[8] Revenues from network service were not considered because any network service revenues LGE / KU would receive would be based on load served within their control area and may represent a transfer payment from one group of Kentucky retail ratepayers to another group of Kentucky retail ratepayers. Revenues for ancillary services other than scheduling, system control, and dispatch also were not considered as these ancillary service revenues are considered to be compensatory based on actual costs.

in the near term LGE / KU will recover more transmission revenues from parties other than control area customers if it remains in MISO, than if it operates as a separate stand alone system.

If LGE / KU were to leave and operate a Stand Alone system, its opportunities for generating transmission revenues from transactions involving parties outside Kentucky would be limited. The LGE / KU system would be an island surrounded on the North, East, and West by the MISO – PJM market and to the South by TVA. Given the availability of direct connections from MISO – PJM into TVA (and from MISO – PJM and TVA to the major Kentucky coops), transmission customers outside Kentucky would rarely, if ever, benefit by purchasing an additional contract path link through LGE / KU's transmission system. The only transmission revenues that LGE / KU can be expected to receive from ratepayers outside Kentucky as a stand alone system will be point-to-point transmission charges built into the gross margins on LGE / KU's export of its own generation or from transmission service to support other export sales of generation located in the LGE / KU control area.

LGE / KU 2002 net non-requirements sales for resale provide a reasonable representation of likely near term exports from the LGE / KU control area. Indeed, stand alone exports may be below 2002 off-system sales levels given the financial hurdle rates that would limit sales from a stand alone LGE / KU system into MISO. Scaling LGE / KU transmission revenues from the Stand Alone PROMOD IV model run[9] to actual 2002 non-requirements sales levels, Stand Alone transmission revenues are projected to be $9.1 million per year.

5. Intermediate to Long-term Market Efficiency Benefits

The inclusion of LGE / KU in transparent markets for energy and transmission capacity will alter incentives and over time behavior in a manner that is likely to produce significant consumer benefits.

While open and competitive LMP power markets are a comparatively recent development, available evidence suggests that such markets contribute to efficiency gains and reductions in consumer prices. For example, Figure RRM_1-1 compares trends in average retail prices for the PJM states, since the opening of the PJM LMP wholesale market in April 1998, and for Kentucky. While there are many factors that affect retail prices, the development of an efficient and transparent wholesale market has had a significant impact in the PJM region. It has created a liquid and transparent market that rewards suppliers for improving availability and holding down costs.

The incentives created by such a market lead participants to discover efficiency improvements that would have been difficult for outside analysts to quantify or regulators to mandate. For example, given an efficient spot market, generation suppliers have a greater incentive to keep their units in operation when prices are higher and generation is more valuable. In PJM, this has led to a significant reduction in forced outages – unplanned outages that could take a plant off line during peak price periods. Figure RRM_1-2 illustrates the reduction in forced outage rates for fossil steam plants and combustion turbines that has occurred since the development of PJM's

[9] Off-system sales from the PROMOD IV Stand Alone scenario may overstate likely Stand Alone sales due to time and modeling limits on representing barriers to efficient utilization of the transmission system.

LMP market.[10] Such improvements have helped drive down the marginal cost of generation in PJM energy markets. And, consumers have benefited from lower production costs and wholesale prices.

The inclusion of LGE / KU in MISO wholesale energy markets does not diminish the authority of state regulators to set retail rates or to review utility resource additions, demand-side programs, or other utility activities.

Cost of service regulation has helped ensure that utilities provide adequate service at prices that do not exceed average costs. However, when compared to competitive markets, rate cases and fuel cost recovery proceedings provide a backstop for cost recovery that may dampen incentives to maximize efficiency. The development of a transparent wholesale market will enhance the options that are available to Kentucky regulators as they seek an appropriate balance between cost of service regulation, incentive regulation, and reliance on markets. If the LGE / KU system is inside MISO's wholesale energy market, the Kentucky Commission would be able to:

- Benchmark utility fuel and operating costs against location-specific spot prices;
- Take advantage of a larger and more liquid wholesale market should it decide to shift from ratepayers to investors some or all of the capital investment risks associated with the development of new generating capacity;
- Use location-specific prices to help identify where it may be cost-effective to build new generation or transmission capacity;
- Design for price responsive consumers variable pricing products which are based on efficient price signals that customers can trust to reflect the actual real-time or day-ahead marginal cost of power; and
- Foster the development of differentiated consumer energy products designed to better match consumer risk preferences.

Without addressing how regulators might distribute efficiency gains between ratepayers and the utility, these options provide opportunities to generate large efficiency gains.

In their 2002 Integrated Resource Plan, the Companies propose adding more than 2200 MW of new generating capacity between 2005 and 2016. The 30 year Present Value Revenue Requirements for the new units in the Companies' optimal generation expansion plan are in excess of $4 billion. (LGE and KU 2002 Optimal Expansion Plan Analysis) Once these investments have been made, the sunk costs will have significant long-term impacts for the Companies and their customers. Today such decisions must be made without the information that a transparent wholesale market could provide on the location specific cost and value of power.

If an efficient transparent market permitted even a modest percentage reduction in required capacity expenditures, the economic benefits would more than offset the costs of MISO membership. While we have not prepared an alternative expansion plan given the time available for this analysis, we have noted two indicators that it may be possible to reduce intermediate term capital expenditures given a transparent market.

[10] The trend toward reduced forced outages in PJM is not the result of changes in the mix of generation in operation. The forced outage rates for plants coming on line prior to 1998 and for all plants are virtually identical.

First, LGE and KU reported in their 2002 Integrated Resource Plan (IRP) steam and combustion turbine forced outage rates that are significantly higher than the comparable average rates achieved in PJM. (Compare: Table RRM_1-8 and Figure RRM_1-2) The potential to improve forced outage rates is likely to depend on unit-specific conditions. However, if LGE / KU average steam and turbine equivalent forced outage rates were reduced from the levels presented in their IRP to match the average rates achieved in PJM as reported by the PJM Market Monitor, this would represent the equivalent of more than 170 MW of capacity.

Second, transparent day ahead and real time energy markets also could facilitate the development of expanded and more economically efficient demand response programs. LGE and KU currently do not operate any variable pricing programs. They serve 15 large customers under interruptible load tariffs. For planning purposes, LGE / KU rely upon 95 MW of demand reduction from these interruptible load customers. Additionally, the Companies have enrolled 30,000 residential and commercial consumers in a Demand Conservation Program that permits the utilities to reduce air conditioning demand by approximately 35 MW. While the design of specific variable programs is beyond the scope of this analysis, the Companies' limited involvement in this area to date and typical commercial and industrial short-term price elasticities suggest that a well designed variable pricing program operated within the context of a transparent spot market might achieve an additional 100 MW or more of peak demand reduction. Such programs can succeed where there are transparent spot markets or where the programs provide a basis on which the utility competes to serve retail customers in its service territory. In both cases, the existence of a market helps assure program participants that the prices offered by the utility are reasonable. If variable pricing programs are developed in the context of a transparent spot market, an additional benefit can be achieved. The day-ahead and real-time market prices reflect the time-specific marginal cost of power at specific locations on the transmission grid. Pegging the variable price component of a multi-part variable price product to market prices will optimize consumer welfare by aligning the time- and location-specific marginal cost of power with its marginal value to price responsive customers. Variable pricing programs can be highly cost effective because they leverage existing capabilities that customers may have to manage load and capture the true value that consumers place on additional energy consumption.

Over a longer time horizon, transparent power markets will influence the pattern and location of generation and transmission investments. Market influenced outcomes may be greatly superior to decisions based entirely on centralized planning. For example, the market would take into consideration the real option value of deferring the decision to invest under conditions of uncertainty. Such appropriate factors often are not considered when comparing the expected cost of alternative capacity expansion plans in the context of a regulatory proceeding.

The cost of MISO membership is a modest investment in comparison to potential benefits for Kentucky consumers from intermediate and longer-term efficiency gains that may be driven by the LGE / KU system being included in a transparent wholesale power market.

Table RRM_1-1

Summary of the Near-Term Benefits and Costs of MISO Membership and Stand Alone Operation of the LGE / KU Transmission System

	2004	2005	2006	2007	2008	2009	2010
Cost of MISO Membership							
System Operations & Transmission Costs							
MRMD Staffing, Training, Consulting		$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
Miscellaneous Uplift Charges		$500,000	$500,000	$500,000	$500,000	$500,000	$500,000
Congestion Costs Not Covered by FTRs		$73	$73	$73	$73	$73	$73
Implementation and Administration Costs							
Total of Schedules 10, 16, 17 Charges		$13,224,856	$13,647,730	$13,945,651	$13,920,299	$13,467,466	$12,338,477
Ancillary Market Cost				$280,000	$280,000	$280,000	$280,000
Legal, Regulatory, & Transaction Costs							
Net Cost of Committee Participation, Contracts		$400,000	$400,000	$400,000	$400,000	$400,000	$400,000
Net FERC Attachment O Fees		$860,000	$860,000	$860,000	$860,000	$860,000	$860,000
Less: Transmission Revenues							
Less: MISO Schedule 1, 7, 8, and 14 Revenues		($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)	($21,824,753)
Total Cost of MISO Membership		**-$6,439,824**	**-$6,016,950**	**-$5,439,029**	**-$5,464,381**	**-$5,917,214**	**-$7,046,203**
Cost of Stand Alone Operation							
MISO Exit Fee	$38,200,000						
System Operation Costs							
Additional Staffing		$300,000	$300,000	$300,000	$300,000	$300,000	$300,000
Systems Related Costs		$720,000	$720,000	$720,000	$720,000	$720,000	$720,000
Congestion Management Costs		$3,657,767	$3,657,767	$3,657,767	$3,657,767	$3,657,767	$3,657,767
Lost Revenues							
Lost FTR Revenue		$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000	$2,000,000
Lost Margin on Wholesale Sales		$8,348,007	$8,348,007	$8,348,007	$8,348,007	$8,348,007	$8,348,007
Less: Transmission Revenues							
Less: LGE/KU Sch. 1,7, & 8 Transmission Revenue on Off-System Sales		($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)	($9,148,532)
Total Cost of Stand Alone Operations	**$38,200,000**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**	**$5,877,242**
Net Cost Savings of MISO Membership	**$38,200,000**	**$12,317,066**	**$11,894,192**	**$11,316,271**	**$11,341,623**	**$11,794,456**	**$12,923,445**
Cumulative Net Savings of MISO Membership	**$38,200,000**	**$50,517,066**	**$62,411,259**	**$73,727,530**	**$85,069,153**	**$96,863,610**	**$109,787,055**
Net Present Value Savings from MISO Membership in 2004	**$38,200,000**	**$11,511,277**	**$10,388,848**	**$9,237,448**	**$8,652,470**	**$8,409,284**	**$8,611,437**
Cumulative NPV Savings from MISO Membership	**$38,200,000**	**$49,711,277**	**$60,100,125**	**$69,337,573**	**$77,990,044**	**$86,399,328**	**$95,010,765**

Table RRM_1-2

Analysis of Flowgate Capacity Underutilization during TLR Events
LGE / KU TLR Events with Available Data July - October 2003

Flowgate ID	Flowgate Name	TLR Called	TLR Started	TLR Level	TLR End	Unused Capacity (MWH)	Total Capacity (MWH)	Percent of Total Capacity Not Used During TLR Event
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	7/8/03 21:35	7/8/03 22:00	3a	7/8/03 23:36	0.2	170.1	0.11%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	7/9/03 9:16	7/9/03 9:16	4	7/9/03 16:04	295.1	1867.1	15.80%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	7/19/03 9:49	7/19/03 9:49	4	7/19/03 22:53	335.2	3125.2	10.72%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	7/20/03 9:40	7/20/03 9:40	4	7/20/03 22:29	293.8	3066.6	9.58%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	8/2/03 6:33	8/2/03 6:33	4	8/2/03 15:51	134.2	2228.1	6.02%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	8/31/03 7:20	8/31/03 7:20	4	8/31/03 20:29	187.1	3626.1	5.16%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	9/2/03 5:30	9/2/03 6:00	3a	9/2/03 14:20	23.8	1991.9	1.20%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	9/4/03 5:04	9/4/03 5:04	4	9/4/03 20:41	13.5	3733.0	0.36%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	9/13/03 8:48	9/13/03 9:00	3a	9/13/03 20:40	0.7	2443.8	0.03%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	9/14/03 9:34	9/14/03 10:00	3a	9/14/03 23:35	138.6	3246.6	4.27%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	9/15/03 16:28	9/15/03 17:00	3a	9/15/03 20:29	0.0	832.2	0.00%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	9/26/03 15:36	9/26/03 16:00	3a	9/26/03 22:04	101.3	1449.5	6.99%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	10/20/03 11:28	10/20/03 11:28	4	10/20/03 21:33	101.8	2373.0	4.29%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	10/21/03 6:00	10/21/03 6:00	4	10/21/03 21:28	474.2	4016.9	11.80%
2198	Blue Lick 345/161 XFMR (flo) Baker-Broadford 765	10/22/03 5:53	10/22/03 5:53	4	10/23/03 1:46	1298.0	5554.0	23.37%
2210	Knob Creek-Pond Creek 138 flo Baker-Broadord 765	9/4/03 9:23	9/4/02 10:00	3a	9/4/03 22:02	478.8	2572.5	18.61%
2210	Knob Creek-Pond Creek 138 flo Baker-Broadord 765	10/20/03 11:30	10/20/03 11:30	4	10/20/03 21:47	172.4	2421.2	7.12%
2210	Knob Creek-Pond Creek 138 flo Baker-Broadord 765	10/21/03 6:21	10/21/03 6:21	4	10/21/03 11:34	125.2	1183.9	10.58%
2279	Paddys West-Paddys Run 138 (flo) Cane Run-Cane Run 6 138	9/1/03 14:08	9/1/03 15:00	3a	9/1/03 19:30	0.6	1728.8	0.04%
2279	Paddys West-Paddys Run 138 (flo) Cane Run-Cane Run 6 138	9/4/03 6:28	9/4/03 6:28	4	9/4/03 20:58	766.1	5371.0	14.26%
2279	Paddys West-Paddys Run 138 (flo) Cane Run-Cane Run 6 138	9/5/03 12:21	9/5/03 13:00	3a	9/5/03 20:30	135.2	2780.2	4.86%
2245	Blue Lick-Bullitt Co 161 flo Baker-Broadford 765	8/30/03 7:36	8/30/03 7:36	4	8/30/03 21:31	245.4	3559.5	6.89%
2245	Blue Lick-Bullitt Co 161 flo Baker-Broadford 765	9/18/03 12:21	9/18/03 12:21	4	9/18/03 20:27	64.8	1939.2	3.34%
2053	Galagher-Paddys West 138 flo Jefferson-Rockport 765	7/10/03 7:31	7/10/03 8:00	3a	7/10/03 12:14	2.0	1702.3	0.12%
2500	Newtonville-Cloverport 138 flo Coleman-National Aluminum 161	7/10/03 10:16	7/10/03 11:00	3a	7/10/03 12:15	4.2	181.3	2.32%
2049	Ghent-Batesville 345	8/14/03 10:46	8/14/03 11:00	3a	8/14/03 18:40	4092.1	33302.6	12.29%
2285	Paddys West - Paddys Run 138	8/19/03 8:59	8/19/03 9:00	3a	8/19/03 16:28	128.6	1746.9	7.36%
2096	Blue Lick-Bullitt Co. 161 flo Trimble Co.-Clifty Creek 345	9/17/03 10:08	9/17/03 11:00	3a	9/17/03 20:05	28.3	4802.9	0.59%
	WEIGHTED AVERAGE FOR SAMPLE					9641.2	103584.5	**9.31%**

Table RRM_1-3

MISO, PJM, and LGE / KU Hurdle Rates Used in Hurdle Rate Scenarios

Source to Sink / Component		
MISO to LGE & KU	**On-Peak**	**Off-Peak**
Base Non-Firm Hourly Service*	3.50000	1.75000
Ancillary Service 1 (Scheduling, System Control and Dispatch Service)	0.15137	0.07188
Ancillary Service 2 (Reactive Supply and Voltage Control)	0.37347	0.17736
Ancillary Service 3 (Regulation and Frequency Response Service)**	0.11000	0.11000
Schedule 10 (ISO Cost Recovery)	0.15000	0.15000
Schedule 17 Injection & Withdrawal Costs (Energy Market Support Administrative Service Cost Recovery Adder)	0.05200	0.05200
FERC Adder	0.0733	0.0733
Total Tariff	4.41014	2.38454
Transaction Costs***	3	3
Total Hurdle Rate	7.41014	5.38454

LGE & KU to MISO or PJM	**On Peak**	**Off-Peak**
Schedule 8 Non-Firm Point-to-Point Service	$2.4329	$1.1585
Schedule 1 (Scheduling, System Control, and Dispatch) ****	0.01	0.01
Schedule 2 (Reactive Supply and Voltage Control from Generation Sources) ****	0.3	0.15
Schedule 3 (Regulation & Frequency Response) ****	0.199	0.095
FERC Adder	0.0733	0.0733
Total Tariff	3.01520	1.48680
Transaction Costs***	3	3
Total Hurdle Rate	**6.01520**	**4.48680**

PJM to LGE & KU	**On & Off Peak**
Discounted Non-Firm Price #	0.67
Control Area Services ##	0.3042
Regulation & Frequency Response ##	0.4379
FERC Adder	0.0733
Total Tariff	1.4854
Transaction Costs***	3
Total Hurdle Rate	**4.48540**

Comments

* Includes Schedules:14 (RTOR), 18 (SRA), 19 (ZTA)

** Based on export from Cinergy Bus

*** Incremental transaction and opportunity costs

**** Ancillary Service Charges based on 10/9/97 LG&E/KU Pro Forma Open Access Transmission Tariff

PJM Regional Transmission and Energy Scheduling Practices (Rev'd 9/17/03)

Approved 2004 Rate, Schedules 9 (e) and 9 (g)

Table RRM_1-3

Table RRM_1-4

Cost to Serve LGE / KU Control Area Loads Under Alternative Congestion Management Scenarios

Cost to Serve LGE / KU Control Area Load - LGE / KU in MISO

Month	Variable O&M	Fuel Cost	Emissions Cost	Fixed O&M plus Start Up Costs	Purchased Power Cost	Total Cost to Serve Control Area Load
January	$2,254,529	$40,325,407	$1,825,702	$12,016,136	$116,818	$56,538,593
February	$2,088,759	$34,341,365	$1,456,901	$12,099,854	$319,509	$50,306,388
March	$2,268,796	$34,528,793	$1,493,050	$12,123,911	$1,914,659	$52,329,210
April	$1,986,410	$33,568,561	$2,092,993	$12,211,834	$0	$49,859,798
May	$2,046,579	$35,229,510	$5,341,855	$12,289,776	$1,168,040	$56,075,760
June	$2,256,538	$38,125,757	$6,143,285	$12,484,386	$2,254,691	$61,264,658
July	$2,525,205	$42,795,778	$7,105,456	$12,371,517	$3,069,751	$67,867,707
August	$2,534,075	$42,213,827	$6,946,495	$12,380,487	$2,978,620	$67,053,503
September	$2,075,504	$36,394,451	$5,136,331	$12,430,395	$293,113	$56,329,795
October	$1,967,763	$33,422,791	$1,788,464	$12,194,360	$329,676	$49,703,054
November	$2,143,087	$34,030,776	$1,566,545	$12,245,158	$109,474	$50,095,040
December	$2,210,060	$37,189,449	$1,544,278	$12,393,795	$474,713	$53,812,295
Total	$26,357,305	$442,166,465	$42,441,355	$147,241,609	$13,029,067	$671,235,800

Cost to Serve LGE / KU Control Area Load - LGE / KU Stand Alone: Effective Physical Limits

Month	Variable O&M	Fuel Cost	Emissions Cost	Fixed O&M plus Start Up Costs	Purchased Power Cost	Total Cost to Serve Control Area Load	Additional LGE/KU Stand Alone Cost
January	$2,251,131	$40,336,218	$1,853,195	$12,022,236	$227,483	$56,690,263	$151,670
February	$2,087,217	$34,316,383	$1,459,365	$12,106,454	$401,800	$50,371,219	$64,830
March	$2,258,398	$34,448,905	$1,492,674	$12,123,911	$2,035,585	$52,359,473	$30,263
April	$1,942,902	$33,592,310	$2,111,144	$12,241,634	$0	$49,887,990	$28,192
May	$2,033,030	$35,187,131	$5,355,700	$12,296,576	$1,347,947	$56,220,383	$144,623
June	$2,238,681	$38,241,279	$6,169,185	$12,484,286	$2,412,625	$61,546,056	$281,399
July	$2,521,776	$42,795,379	$7,120,077	$12,366,317	$3,252,788	$68,056,338	$188,630
August	$2,526,614	$42,232,676	$6,982,008	$12,348,387	$3,248,618	$67,338,302	$284,799
September	$2,076,323	$36,451,156	$5,165,619	$12,420,995	$312,120	$56,426,213	$96,418
October	$1,968,251	$33,433,180	$1,794,711	$12,190,860	$349,004	$49,736,006	$32,952
November	$2,145,200	$34,033,424	$1,565,906	$12,235,958	$108,754	$50,089,241	-$5,799
December	$2,203,300	$37,098,716	$1,554,278	$12,384,095	$750,650	$53,991,039	$178,744
Total	$26,252,822	$442,166,754	$42,623,862	$147,221,709	$14,447,374	$672,712,522	**$1,476,722**

Cost to Serve LGE / KU Control Area Load - LGE / KU Stand Alone: Financial Hurdle Rates

Month	Variable O&M	Fuel Cost	Emissions Cost	Fixed O&M plus Start Up Costs	Purchased Power Cost	Total Cost to Serve Control Area Load	Additional LGE/KU Stand Alone Cost
January	$2,256,828	$40,338,393	$1,822,041	$12,022,636	$87,875	$56,527,773	-$10,819
February	$2,090,846	$34,415,085	$1,458,015	$12,099,854	$320,570	$50,384,370	$77,982
March	$2,269,081	$34,660,388	$1,498,815	$12,123,911	$2,070,962	$52,623,157	$293,947
April	$1,986,963	$33,556,735	$2,096,610	$12,220,234	$0	$49,860,542	$745
May	$2,057,661	$35,487,194	$5,374,739	$12,281,876	$1,025,254	$56,226,724	$150,964
June	$2,270,184	$38,482,192	$6,190,895	$12,480,086	$2,042,344	$61,465,702	$201,044
July	$2,529,094	$42,894,716	$7,121,694	$12,395,517	$3,213,408	$68,154,429	$286,722
August	$2,544,447	$42,404,905	$6,981,501	$12,377,787	$2,982,270	$67,290,909	$237,406
September	$2,076,517	$36,423,413	$5,130,678	$12,433,095	$311,898	$56,375,601	$45,806
October	$1,968,192	$33,473,055	$1,789,814	$12,194,360	$322,441	$49,747,861	$44,807
November	$2,142,553	$34,070,428	$1,567,312	$12,245,158	$104,144	$50,129,594	$34,554
December	$2,214,913	$37,252,208	$1,544,642	$12,392,695	$414,418	$53,818,875	$6,581
Total	$26,407,280	$443,458,712	$42,576,756	$147,267,209	$12,895,583	$672,605,539	**$1,369,739**

Cost to Serve LGE / KU Control Area Load - LGE / KU Stand Alone: Effective Physical Limits and Financial Hurdle Rates

Month	Variable O&M	Fuel Cost	Emissions Cost	Fixed O&M plus Start Up Costs	Purchased Power Cost	Total Cost to Serve Control Area Load	Additional LGE/KU Stand Alone Cost
January	$2,291,271	$40,359,330	$1,880,035	$12,023,136	$208,401	$56,762,173	$223,580
February	$2,130,772	$34,376,306	$1,475,427	$12,099,754	$410,315	$50,492,573	$186,184
March	$2,287,606	$34,582,681	$1,498,715	$12,117,711	$2,298,421	$52,785,134	$455,924
April	$2,013,235	$33,595,454	$2,142,422	$12,198,634	$0	$49,949,745	$89,948
May	$2,061,330	$35,374,239	$5,430,041	$12,294,676	$1,360,162	$56,520,448	$444,688
June	$2,283,419	$38,597,881	$6,259,954	$12,478,086	$2,209,017	$61,828,357	$563,699
July	$2,545,464	$42,898,756	$7,164,695	$12,379,017	$3,463,578	$68,451,510	$583,803
August	$2,562,861	$42,426,484	$7,029,464	$12,387,287	$3,103,813	$67,509,908	$456,405
September	$2,104,065	$36,500,126	$5,199,048	$12,436,595	$310,676	$56,550,510	$220,715
October	$1,977,773	$33,484,193	$1,802,120	$12,191,060	$348,305	$49,803,451	$100,397
November	$2,149,613	$34,055,370	$1,571,113	$12,244,258	$111,024	$50,131,377	$36,338
December	$2,255,353	$37,126,903	$1,580,558	$12,395,895	$749,670	$54,108,380	$296,085
Total	$26,662,762	$443,377,721	$43,033,593	$147,246,109	$14,573,382	$674,893,567	**$3,657,767**

Table RRM_1-5

LGE / KU Stand Alone Cost: Lost Net Margin on Off-System Sales

Net Margin on Off-System Sales LGE / KU in MISO (PROMOD IV Model Run)

Month	LGE / KU Total Generation Cost	LGE / KU Generation Costs in Cost to Serve Control Area Load	LGE / KU Cost of Off-System Sales	Off-System Sales Revenue at Generator LMP	Net Margin On LGE / KU Off-System Sales
January	$69,478,816	$56,421,775	$13,057,042	$14,570,650	$1,513,609
February	$60,927,879	$49,986,879	$10,941,001	$11,828,881	$887,880
March	$57,913,019	$50,414,550	$7,498,469	$9,247,749	$1,749,280
April	$67,743,174	$49,859,798	$17,883,377	$23,914,638	$6,031,262
May	$63,918,836	$54,907,719	$9,011,117	$9,151,973	$140,856
June	$67,171,022	$59,009,967	$8,161,055	$8,688,303	$527,248
July	$73,802,070	$64,797,956	$9,004,114	$10,367,393	$1,363,279
August	$73,390,671	$64,074,883	$9,315,787	$10,682,552	$1,366,765
September	$68,357,083	$56,036,682	$12,320,401	$14,323,479	$2,003,078
October	$58,316,571	$49,373,378	$8,943,193	$10,777,486	$1,834,293
November	$62,286,744	$49,985,565	$12,301,178	$14,601,005	$2,299,827
December	$68,080,084	$53,337,582	$14,742,502	$16,733,712	$1,991,210
Total	$791,385,970	$658,206,733	$133,179,236	$154,887,823	**$21,708,586**

Modeled LGE / KU Net Margin on Off-System Sales - LGE / KU Stand Alone: Effective Physical Limits and Financial Hurdle Rates (PROMOD IV Model Run)
Overstates Off-System Sales Due to Time and Modeling Limits on Ability to Model Barriers to Effective Utilization of Transmission

Month	LGE / KU Total Generation Cost	LGE / KU Generation Costs in Cost to Serve Control Area Load	LGE / KU Cost of Off-System Sales	Off-System Sales Revenue at Generator LMP	Net Margin On LGE / KU Off-System Sales
January	$66,923,142	$56,553,772	$10,369,370	$11,382,240	$1,012,871
February	$59,050,647	$50,082,258	$8,968,389	$9,599,985	$631,596
March	$57,416,512	$50,486,713	$6,929,799	$8,574,293	$1,644,494
April	$65,959,174	$49,949,745	$16,009,429	$20,650,866	$4,641,437
May	$63,613,185	$55,160,286	$8,452,899	$8,665,354	$212,454
June	$67,580,803	$59,619,340	$7,961,463	$8,714,152	$752,689
July	$73,892,984	$64,987,932	$8,905,051	$10,138,317	$1,233,266
August	$74,362,588	$64,406,095	$9,956,493	$11,457,484	$1,500,991
September	$68,928,521	$56,239,834	$12,688,687	$14,714,629	$2,025,941
October	$58,321,276	$49,455,146	$8,866,129	$10,607,992	$1,741,863
November	$61,594,076	$50,020,353	$11,573,723	$13,834,650	$2,260,927
December	$65,859,468	$53,358,710	$12,500,758	$13,892,032	$1,391,274
Total	$783,502,376	$660,320,185	$123,182,191	$142,231,994	**$19,049,803**

Scaling of Stand Alone Net Margin on Off-System Sales to 2002 Actual Net Non-Requirements Sales for Resale

Description	Value	Line Number	Comment
Modeled LGE / KU Stand Alone Off-System Sales (MWH)	8,048,477	(1)	LGE/KU Stand Alone: Effective Physical Limits and Financial Hurdle Rates Scenario
LGE / KU 2002 Non-Requirements Sales (MWH)	5,644,761	(2)	2002 FERC Form 1 Net Non-Requirements Sale for Resale
Ratio of Actual 2002 to Modeled Stand Alone Sales (%)	70.1%	(3)	Line 2 / Line 3
Modeled Stand Alone Net Margin on Off-System Sales ($)	$19,049,803	(4)	LGE/KU Stand Alone: Effective Physical Limits and Financial Hurdle Rates Scenario
Stand Alone Net Margin Scaled to 2002 Non-Requirements Sales ($)	$13,360,579	(5)	Line 4 * Line 3
LGE / KU in MISO Net Margin on Off-System Sales ($)	$21,708,586	(6)	LGE / KU in MISO Scenario
Stand Alone Cost: Lost Net Margin on Off-System Sales ($)	**$8,348,007**	(7)	Line 6 - Line 5

Table RRM_1-6

Congestion Costs Incurred to Serve LGE / KU Control Area Load Not Covered by FTR Allocation
Based on December 19, 2003 FTR Test Allocation

Total FTR Allocation to LGE / KU	7035.134 MW
FTR Allocation to Serve LGE / KU Control Area Load	6617.35 MW

Control Area Load > FTR Allocation			Congestion Component of LMP ($/MWh) Load & Generation Congestion Costs Relative to Reference Bus					
Date	**Hour**	**Load (MW)**	**Load LMP Congestion Cost ($/MWH)**	**Generation LMP Congestion Cost ($/MWH)**	**Net Generation to Load Congestion Cost ($/MWH)**	**Congestion Cost ($)**	**Load in Excess of FTRs to Serve Control Area Load (MW)**	**Congestion Costs Not Covered by FTRs ($)**
6/10/04	14	6697	-0.077	-0.591	0.514	$3,442	79.65	$41
6/10/04	15	6785	0.233	-0.348	0.581	$3,942	167.65	$97
6/10/04	16	6792	0.007	-0.517	0.524	$3,559	174.65	$92
6/10/04	17	6743	0.024	-0.521	0.545	$3,675	125.65	$68
6/10/04	18	6627	-0.031	-0.571	0.54	$3,579	9.65	$5
6/15/04	15	6669	24.724	22.49	2.234	$14,899	51.65	$115
6/15/04	16	6730	22.643	20.829	1.814	$12,208	112.65	$204
6/15/04	17	6652	24.871	22.416	2.455	$16,331	34.65	$85
7/6/04	14	6718	1.678	0.721	0.957	$6,429	100.65	$96
7/6/04	15	6848	0.885	0.153	0.732	$5,013	230.65	$169
7/6/04	16	6901	1.531	0.622	0.909	$6,273	283.65	$258
7/6/04	17	6946	0.855	0.129	0.726	$5,043	328.65	$239
7/6/04	18	6791	0.707	0.016	0.691	$4,693	173.65	$120
7/19/04	14	6783	-1.084	-0.745	-0.339	-$2,299	165.65	-$56
7/19/04	15	6815	-1.885	-0.474	-1.411	-$9,616	197.65	-$279
7/19/04	16	6721	-0.524	-0.194	-0.33	-$2,218	103.65	-$34
7/20/04	13	6836	-1.937	-0.004	-1.933	-$13,214	218.65	-$423
7/20/04	14	6972	-0.773	-0.242	-0.531	-$3,702	354.65	-$188
7/20/04	15	7034	-2.969	-0.055	-2.914	-$20,497	416.65	-$1,214
7/20/04	16	7020	-1.5	-0.095	-1.405	-$9,863	402.65	-$566
7/20/04	17	6958	-3.154	-0.125	-3.029	-$21,076	340.65	-$1,032
7/20/04	18	6806	-0.492	-0.118	-0.374	-$2,545	188.65	-$71
7/21/04	13	6836	-1.073	1.039	-2.112	-$14,438	218.65	-$462
7/21/04	14	6862	1.154	0.244	0.91	$6,244	244.65	$223
7/21/04	15	6861	1.175	0.295	0.88	$6,038	243.65	$214
7/21/04	16	6875	1.258	0.358	0.9	$6,188	257.65	$232
7/21/04	17	6783	0.844	0.068	0.776	$5,264	165.65	$129
7/21/04	18	6692	2.181	1.076	1.105	$7,395	74.65	$82
7/26/04	14	6658	0.508	-0.123	0.631	$4,201	40.65	$26
7/26/04	15	6767	0.744	0.047	0.697	$4,717	149.65	$104
7/26/04	16	6820	0.57	-0.074	0.644	$4,392	202.65	$131
7/26/04	17	6761	0.639	0.02	0.619	$4,185	143.65	$89
7/26/04	18	6682	0.616	-0.051	0.667	$4,457	64.65	$43
7/27/04	13	6627	0.401	0.194	0.207	$1,372	9.65	$2
7/27/04	14	6814	0.593	0.065	0.528	$3,598	196.65	$104
7/27/04	15	6933	0.529	0.137	0.392	$2,718	315.65	$124
7/27/04	16	6990	0.366	-0.095	0.461	$3,222	372.65	$172
7/27/04	17	6911	0.251	-0.179	0.43	$2,972	293.65	$126
7/27/04	18	6746	0.494	-0.021	0.515	$3,474	128.65	$66
7/28/04	13	6706	0.681	0.162	0.519	$3,480	88.65	$46
7/28/04	14	6944	-0.399	-0.31	-0.089	-$618	326.65	-$29
7/28/04	15	7042	0.441	-0.078	0.519	$3,655	424.65	$220
7/28/04	16	7060	0.012	-0.087	0.099	$699	442.65	$44

Date	Hour	Load (MW)	Load LMP Congestion Cost ($/MWH)	Generation LMP Congestion Cost ($/MWH)	Net Generation to Load Congestion Cost ($/MWH)	Congestion Cost ($)	Load in Excess of FTRs to Serve Control Area Load (MW)	Congestion Costs Not Covered by FTRs ($)
7/28/04	17	7025	0.153	0.044	0.109	$766	407.65	$44
7/28/04	18	6851	0.5	0.032	0.468	$3,206	233.65	$109
7/29/04	13	6744	1.106	1.14	-0.034	-$229	126.65	-$4
7/29/04	14	6931	1.806	1.313	0.493	$3,417	313.65	$155
7/29/04	15	7053	2.206	1.892	0.314	$2,215	435.65	$137
7/29/04	16	7074	2.731	2.427	0.304	$2,150	456.65	$139
7/29/04	17	6950	2.614	2.323	0.291	$2,022	332.65	$97
7/29/04	18	6692	2.013	1.457	0.556	$3,721	74.65	$42
8/2/04	14	6728	0.032	-0.423	0.455	$3,061	110.65	$50
8/2/04	15	6864	-0.385	-0.324	-0.061	-$419	246.65	-$15
8/2/04	16	6894	0.205	0.014	0.191	$1,317	276.65	$53
8/2/04	17	6819	-0.43	-0.54	0.11	$750	201.65	$22
8/2/04	18	6666	-0.295	-0.23	-0.065	-$433	48.65	-$3
8/3/04	13	6760	-1.351	-0.94	-0.411	-$2,778	142.65	-$59
8/3/04	14	6880	-1.385	-0.864	-0.521	-$3,584	262.65	-$137
8/3/04	15	6955	-2.17	-1.391	-0.779	-$5,418	337.65	-$263
8/3/04	16	6958	-2.121	-1.355	-0.766	-$5,330	340.65	-$261
8/3/04	17	6883	-1.607	-1.085	-0.522	-$3,593	265.65	-$139
8/3/04	18	6739	-1.731	-1.073	-0.658	-$4,434	121.65	-$80
8/4/04	13	6834	-0.692	-0.301	-0.391	-$2,672	216.65	-$85
8/4/04	14	7009	-0.643	-0.272	-0.371	-$2,600	391.65	-$145
8/4/04	15	7045	0.358	-0.031	0.389	$2,741	427.65	$166
8/4/04	16	7096	-0.138	-0.014	-0.124	-$880	478.65	-$59
8/4/04	17	7032	-0.007	-0.084	0.077	$541	414.65	$32
8/4/04	18	6862	-0.2	-0.049	-0.151	-$1,036	244.65	-$37
8/4/04	19	6681	-0.218	-0.147	-0.071	-$474	63.65	-$5
8/5/04	13	6667	-0.369	-0.386	0.017	$113	49.65	$1
8/5/04	14	6714	-0.072	-0.108	0.036	$242	96.65	$3
8/5/04	15	6620	0.037	-0.324	0.361	$2,390	2.65	$1
8/5/04	16	6627	0.038	-0.37	0.408	$2,704	9.65	$4
8/19/04	13	6638	1.609	0.519	1.09	$7,235	20.65	$23
8/19/04	14	6791	0.676	-0.001	0.677	$4,598	173.65	$118
9/1/04	16	6682	0.677	-0.007	0.684	$4,570	64.65	$44
9/1/04	17	6625	2.043	0.609	1.434	$9,500	7.65	$11
9/2/04	15	6769	3.962	1.408	2.554	$17,288	151.65	$387
9/2/04	16	6873	0.324	-0.248	0.572	$3,931	255.65	$146
9/2/04	17	6820	0.732	0.039	0.693	$4,726	202.65	$140
9/2/04	18	6665	0.197	-0.357	0.554	$3,692	47.65	$26
TOTAL						**$120,283**		**$73**

Table RRM_1-7

LGE / KU Transmission Revenue received from MISO

	Schedule 7 Firm Point-to-Point	Schedule 8 Non-Firm Point-to-Point	Schedule 1 Scheduling, System Control & Dispatch	Schedule 14 Regional Through and Out Rates	Total
December-02	1,332,299.47	141,045.25	77,335.89	296,458.42	1,847,139.03
January-03	1,135,838.44	480,938.71	98,602.13	347,507.68	2,062,886.96
February-03	286,284.27	505,354.10	51,330.33	249,265.67	1,092,234.37
March-03	370,109.12	749,657.16	73,708.62	339,694.76	1,533,169.66
April-03	291,419.59	954,818.95	77,870.50	259,235.44	1,583,344.48
May-03	202,895.36	662,195.10	55,446.21	223,208.04	1,143,744.71
June-03	247,454.36	1,070,095.96	88,484.44	307,940.65	1,713,975.41
July-03	228,949.61	1,255,631.44	95,617.98	308,780.23	1,888,979.26
August-03	281,984.01	1,082,453.21	88,390.76	316,461.11	1,769,289.09
September-03	280,211.66	1,165,152.64	93,604.07	327,091.29	1,866,059.66
October-03	298,042.80	1,927,299.02	112,963.20	404,531.88	2,742,836.90
November-03	299,712.14	1,755,430.89	102,556.77	423,393.95	2,581,093.75
Total	**5,255,200.83**	**11,750,072.43**	**1,015,910.90**	**3,803,569.12**	**21,824,753.28**

Table RRM_1-8

LGE / KU Equivalent Forced Outage Rates

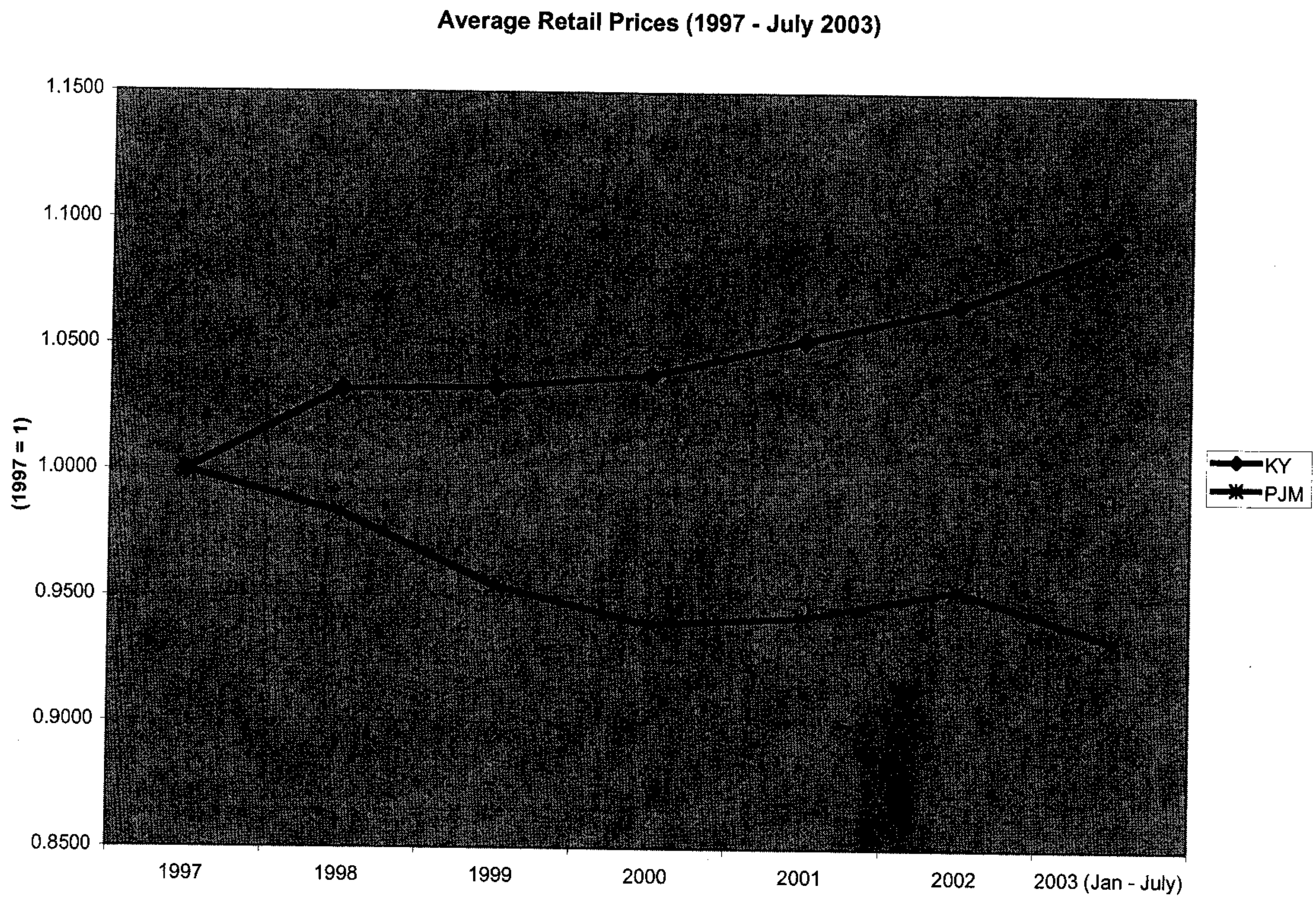
LGE/KU 2002 Integrated Resource Plan, 2002 Optimal Expansion Plan Analysis, Appendix A, Table 3

Fossil Steam Units

Unit Name	Summer Capacity (MW)	Equivalent Forced Outage Rate (%)
Brown 1	104	4.37%
Brown 2	168	6.73%
Brown 3	429	6.67%
Cane Run 4	155	10.70%
Cane Run 5	168	17.65%
Cane Run 6	240	16.66%
Ghent 1	509	5.38%
Ghent 2	494	3.23%
Ghent 3	496	3.91%
Ghent 4	467	2.83%
Green River 1	22	15.11%
Green River 2	22	15.11%
Green River 3	68	5.02%
Green River 4	100	13.18%
Mill Creek 1	308	11.64%
Mill Creek 2	306	11.85%
Mill Creek 3	391	10.97%
Mill Creek 4	480	14.98%
Trimble 1	386	4.88%
Tyrone 1	27	58.24%
Tyrone 2	31	0.38%
Tyrone 3	71	4.46%

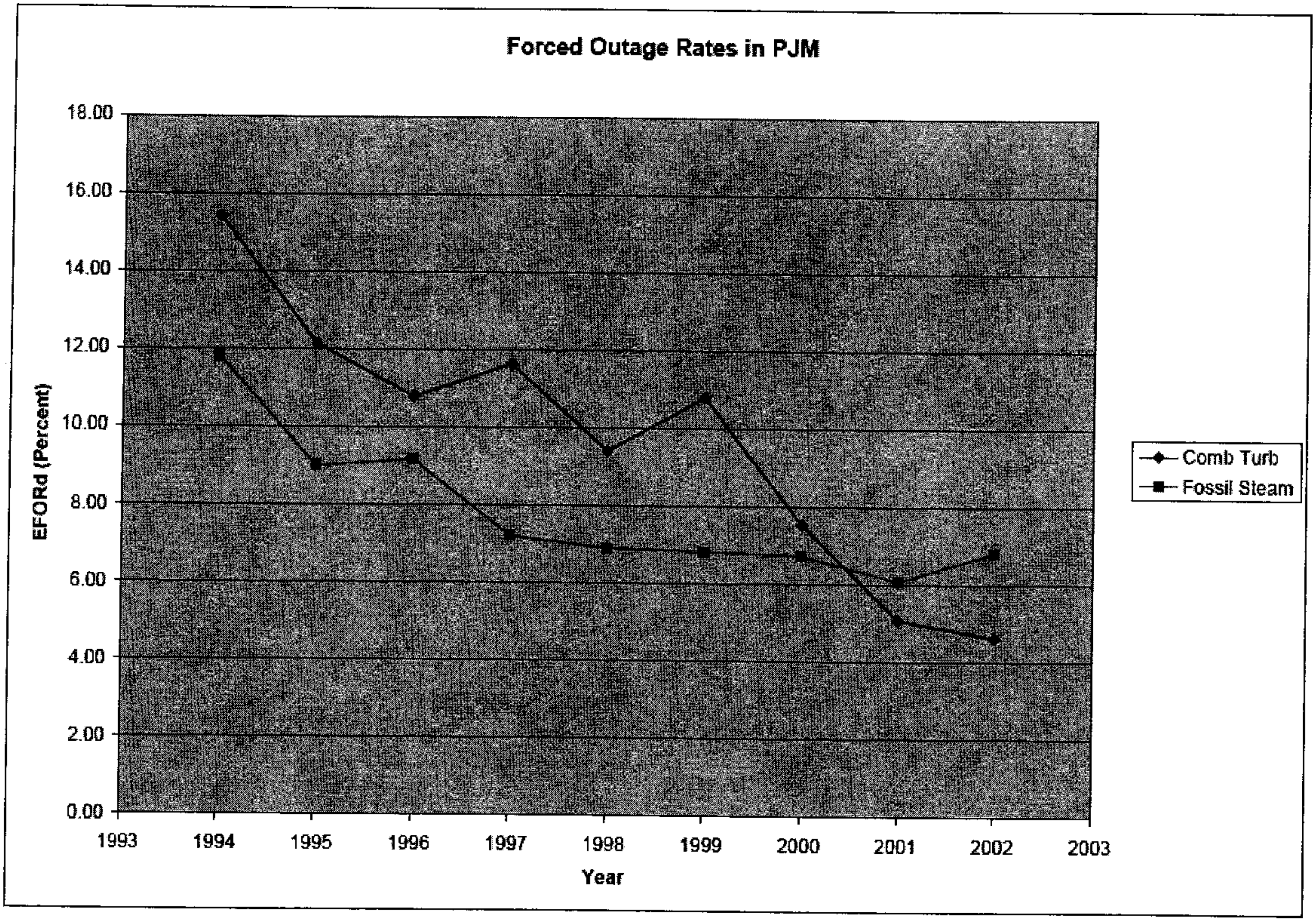
Combustion Turbine Units

Unit Name	Summer Capacity (MW)	Equivalent Forced Outage Rate (%)
Brown 5	134	8.00%
Brown 6	154	8.00%
Brown 7	154	8.00%
Brown 8	130	8.00%
Brown 9	130	8.00%
Brown 10	130	8.00%
Brown 11	130	8.00%
Cane Run 11	14	50.00%
Haefling 1	12	66.19%
Haefling 2	12	66.19%
Haefling 3	12	66.19%
Paddy's Run 11	12	50.00%
Paddy's Run 12	23	50.00%
Paddy's Run 13	158	8.00%
Trimble 5	155	8.00%
Trimble 6	155	8.00%
Waterside 7	11	50.00%
Waterside 8	11	50.00%
Zorn 1	14	50.00%



Source: U. S. Energy Information Administration (Revenues All Sectors / MWH Sales All Sectors)

Figure RRM_1-1



Source: PJM Market Monitor

Figure RRM_1-2