COMMONWEALTH OF KENTUCKY
BEFORE THE PUBLIC SERVICE COMMISSION

In the Matter of:

INVESTIGATION INTO THE MEMBERSHIP OF LOUISVILLE GAS AND ELECTRIC AND KENTUCKY UTILITIES COMPANY IN THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.	)	**CASE NO. 2003-00266**

INITIAL POST-HEARING BRIEF OF THE MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

Katherine K. Yunker
Benjamin D. Allen
YUNKER & ASSOCIATES
P.O. Box 21784
Lexington, KY 40522
Telephone: (859) 255-0629
Facsimile: (859) 255-0746

Stephen G. Kozey
James C. Holsclaw
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.
701 City Center Drive
Carmel, IN 46032
Telephone: (317) 249-5850
Facsimile: (317) 697-0792

Stephen L. Teichler
Sarah E. Rogers
DUANE MORRIS, LLP
1667 K Street, N.W., Suite 700
Washington, DC 20006-1608
Telephone: (202) 776-7830
Facsimile: (202) 776-7801

Attorneys for Intervenor
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

TABLE OF CONTENTS

Page

The Midwest Independent Transmission System Operator, Inc. ("Midwest ISO"), an intervenor, hereby presents its Initial Post-Hearing Brief in the above-referenced proceeding in support of its position that continued membership of Louisville Gas and Electric Company ("LG&E") and Kentucky Utilities Company ("KU") in the Midwest ISO provides benefits that far outweigh the cost, and as such, serves the public interest.

SUMMARY OF THE PROCEEDINGS

By an order issued July 17, 2003, the Kentucky Public Service Commission ("Commission") opened an investigation of the membership of LG&E and KU (collectively, "LGE") in the Midwest ISO.[1] A number of issues were specifically identified for review in the case, including whether LGE receives benefits from the services provided by the Midwest ISO commensurate with the costs, as well as the feasibility of its joining another Regional Transmission Organization ("RTO"). In the order, the Commission directed LGE to provide testimony on, among other things, the costs and benefits of membership in the Midwest ISO. The Commission also established a procedural schedule that provided for written discovery, an informal conference, and a formal hearing. On August 22, 2003, the Commission granted the Midwest ISO's motion to intervene. A substantial evidentiary record was created through prefiled testimony, multiple rounds of data requests, and a public hearing held on February 25-27 and April 8, 2004. The parties filed initial and reply briefs, and the matter was submitted for the Commission's decision by late May 2004.

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[1] *In the Matter of Investigation into Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.,* Case No. 2003-00266, Order (July 17, 2003).

In its prefiled testimony and post-hearing briefs, LGE took the position that withdrawal from the Midwest ISO and operation on a stand-alone basis would be more advantageous to it, and asked the Commission to direct it to seek authority from the Federal Energy Regulatory Commission ("FERC") to withdraw from the Midwest ISO. It also asked the Commission to allow recovery for both the costs of the withdrawal, should authority to withdraw be granted by the FERC, and the ongoing costs of membership until withdrawal. Information presented by the Midwest ISO and cross-examination of LGE's witnesses demonstrated that withdrawal from the Midwest ISO and consequent transfer of control over LGE transmission facilities was not in the public interest — the benefits from continued membership could be anticipated to exceed the associated costs.

On March 31, 2004, the Midwest ISO had filed a Transmission and Energy Markets Tariff ("TEMT") with FERC, providing for security-constrained unit commitment and economic dispatch to manage congestion within its region. The TEMT also established day-ahead and real-time energy markets to obtain the information — offers and bids — needed to coordinate unit commitment and dispatch for the region. Concurrently with a request from LGE, the Commission issued an order on June 22, 2004, reopening the evidentiary record in the case to allow for supplemental testimony addressing the impact of the TEMT on the costs and benefits of Midwest ISO membership.[2] Additional rounds of data requests, informal conferences, and testimony followed. LGE and the Midwest ISO filed a Joint Stipulation on December 7, 2004, setting forth their agreement on certain statements about the operation of the Day 2 market. By letter dated December 28, 2004, LGE invoked a provision of the Transmission Owners'

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[2] *In the Matter of Investigation into Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.,* Case No. 2003-00266, Order (June 22, 2004).

agreement and notified the Midwest ISO of its intent to withdraw from membership as early as midnight, December 31, 2005.

Meanwhile, work continued on implementing the energy markets as contemplated by the TEMT. At 12:01 A.M. on April 1, 2005, the Midwest ISO implemented Day 2 operations within its region.[3] By order issued June 22, 2005, the Commission allowed the parties to file supplemental testimony as to actual results and experience of Day 2 operations.[4] Another public hearing was held on July 20-21, 2005. Concurrent initial briefs are due on September 6, 2005; reply briefs, on September 13, 2005.

ISSUES PRESENTED

1. Do Day 2 transmission operations enhance the net benefits of LGE's continued membership in the Midwest ISO?

As demonstrated by actual results, the answer to this question is "yes."

2. Has LGE shown the feasibility of any alternative to continued membership in the Midwest ISO?

As discussed in parts IV-VI below, the answer to this question is "no."

SUMMARY OF THE ARGUMENT

Following the launch of Day 2 operations at 12:01 A.M. on April 1, 2005, the TEMT has been functioning to successfully match demand bids and offers to supply power at specific load and generator locations. The TEMT's utilization of centralized, security-constrained economic

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3 *See* Updated Supplemental Testimony of Ronald R. McNamara, filed July 7, 2005 ("RRM 7/7/05 Supp. Test.") at 2:18. Reference herein to prefiled testimony will be to the witness's initials, filing date, an indication of the type of testimony (*i.e.*, Supplemental, Rebuttal, Direct, etc.), and a page/line reference where applicable.

4 *In the Matter of Investigation into Membership of Louisville Gas and Electric Company and Kentucky Utilities Company in the Midwest Independent Transmission System Operator, Inc.,* Case No. 2003-00266, Order (June 22, 2005).

dispatch, which is designed to achieve reliable, efficient, and transparent system dispatch through the use of locational marginal pricing, is creating economic gains and improving reliability for the entire system. The Midwest ISO's energy markets provide substantial reliability benefits by effectively managing congestion and loop flows through Kentucky and the wider region and by significantly reducing the occurrence of transmission service curtailments. In addition, implementation of Day 2 operations has produced economic benefits for market participants in excess of the costs associated therewith, including, but not limited to, increased revenues from off-system power sales and decreased costs associated with managing transmission constraints.

The authority of the Commission to set rates and ensure electric service for Kentucky consumers is not, in any way, diminished by the TEMT or the establishment of a centralized, security-constrained economic dispatch protocol for the Midwest ISO footprint. Pursuant to the TEMT, LGE remains free to submit transmission schedules to meet native load demand with its own resources, as existed prior to Day 2 operations. In contrast, adverse consequences may arise if LGE withdraws from the Midwest ISO, including loss of market-based pricing authority. Moreover, the cost of exiting will likely be higher than that assumed by LGE in its analysis. As such, continued membership in the Midwest ISO, and hence, not having to pay an exit fee, significantly increases the net benefits of membership.

Finally, there are no adequate alternatives to participation in the Midwest ISO. LGE speaks in vague generalities about operating as a Transmission Operations-Reliability Coordinator ("TORC"), but provides no details as to costs, capabilities, feasibility, or the identity of its substitute Reliability Coordinator. LGE's own witness concludes there is no RTO that would serve that is as economically attractive as the Midwest ISO. This is particularly noteworthy inasmuch as this Commission has previously found participation by a Kentucky utility in PJM Interconnection, LLC ("PJM") served the public interest notwithstanding that PJM is a more expensive RTO than the Midwest ISO.

The Midwest ISO does not stand in an adversarial role to LGE. Indeed, its initial participation in this case was at LGE's request. The Midwest ISO does, however, have an interest in the accurate portrayal of its operations and the fact that security-constrained economic dispatch creates monetary benefits and promotes the reliable and efficient utilization of the transmission grid within the Midwest. The record demonstrates that membership in the Midwest ISO brings a net benefit to LGE customers in Kentucky, and, hence, the public interest does not favor LGE's withdrawal from the Midwest ISO.

DISCUSSION

I. Day 2 Transmission Operations in a Nutshell.

The electric service industry is highly complex and has spawned a bewildering number of acronyms to explain its operations and processes.[5] In many respects, the Midwest ISO's Day 2 transmission operations epitomize such jargon. The welter of acronyms and the sheer size of the Midwest ISO's TEMT obscures the regional transmission system and the structure of the related markets. At its root, however, the Day 2 market shares many attributes of familiar markets for basic commodities, with an overlay necessary to operate and meet the reliability needs of an electric grid.

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[5] A good example is provided by the first paragraph of *PPL Wallingford Energy LLC v. FERC*, No. 03-1292, 2005 U.S. App. LEXIS 16587, *1 (D.C. Cir. Aug. 9, 2005):

> This case raises the question of whether FERC's rejection of a PPL-ISO-NE RMR agreement covering CTs in a NEPOOL DCA violates the APA because FERC ignored PPL's objections to FERC's PUSH and LMP assumptions. We conclude that it does. For those not fluent in the language of FERC, a translation follows.

Day 2 transmission operations permit the Midwest ISO to coordinate the commitment and dispatch of resources so as to more reliably and cost-effectively operate the transmission system. The TEMT provides for the centralized, security-constrained economic dispatch of generation resources in the Midwest ISO region to meet real-time demand for electricity.[6] This dispatch of generation resources is accomplished through an optimization of all available generation resources, taking into account the operating characteristics and restrictions of the transmission system such as transmission congestion and losses.[7]

Regional unit commitment and dispatch has three key implications. First, just as LG&E and KU saved money by jointly dispatching their generation after their merger, regional unit commitment and dispatch reduces production costs for RTO members.[8] Second, the TEMT provides tools that will ensure that LGE's transmission system will be fully utilized and efficiently operated. The electric power system is unique in that, unlike a gas pipeline, it is not a switched network. Power flows automatically and instantaneously across all available transmission paths throughout a large regional area. The primary way to manage power flows is by changing the dispatch of generation, generating more power at Location A and less at Location B, to take into consideration regional power flows and limitations on transmission capacity of specific facilities. By comprehensively monitoring regional power flows and, under its TEMT, optimizing the dispatch of generation every 5 minutes, the Midwest ISO is able to anticipate and avoid reliability risks, safely reduce the historical under-utilization of LGE's

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6 *See, e.g.,* RRM 7/7/05 Supp. Test. at 3:3-5.

7 *Id.* at 3:5-12.

8 *See* Direct Testimony of Dr. Ronald R. McNamara filed December 29, 2003 ("RRM 12/29/03 Direct") at 5:18-20.

transmission system, and reduce the cost of meeting consumer energy requirements.[9] Finally, operation of the Day 2 market under the TEMT increases transparency that will assist this Commission in the achievement of its regulatory objectives.[10]

To implement regional unit commitment and economic dispatch, the Midwest ISO has created day-ahead and real-time energy markets.[11] In these markets, generators submit offers that reflect the price at which they would be willing to generate power.[12] Every five minutes, in the case of the real-time market, the market clears at location-specific prices for every generator and load center.[13] These price signals provide incentives to improve the efficiency with which LGE operates.[14] The results of LGE's market participation, which are available to this Commission, will permit the Commission to:

- Benchmark utility fuel and operating costs;
- Take advantage of a large and liquid wholesale market to reduce the impact on ratepayers of investment and forward market risks;
- Use location-specific prices to identify where it may be cost effective to build new generation or transmission capacity; and
- Facilitate the design of variable pricing products for price responsive customers and energy products that better match different risk preferences.[15]

Transparent price signals provide incentives that will improve the efficiency with which LGE operates.[16] For example, when comparable markets were implemented in PJM, the average

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9 *Id.* at 7:12-14.

10 *Id.* at 5:13.

11 *See* Supplemental Direct Testimony of Ronald R. McNamara, filed September 29, 2004 ("RRM 9/29/04 Direct"), at 13:13-15.

12 *Id.*

13 *Id.* at 13:15-17.

14 *See* RRM 12/29/03 Direct at 7:15-17.

15 *See, e.g.,* RRM 9/29/04 Direct at 22:13-18; RRM 12/29/03 Direct at 7:5-8, 15-17, 19:14-16.

forced outage rates for fossil steam plants fell by 40% and for combustion turbines by 70% as generators sought to ensure that their plants would be available when power is most valuable.[17] If LGE were to achieve comparable rates of availability, it could avoid the need for more than 170 MW of new capacity.[18] Transparency also reveals what investments may be cost-effective in a manner seldom captured in resource planning studies. For example, since market start, the Midwest ISO has found that the actual market value of electricity can be higher – more than $100 per MWh higher in some hours – to the east of constraints in the LGE transmission system than it is near the Louisville load center.[19] Midwest ISO modeling forecasted this pattern and projected that on an annual basis, locating a single combustion turbine east of these constraints, instead of where LGE plans to add generation, could save consumers $2.2 million per year.[20] The narrow issues about short-term benefits and costs on which LGE has focused have to be assessed against the backdrop of what are clearly large operational, reliability, and market transparency benefits created by the Midwest ISO's operation of LGE transmission facilities as part of the regional grid.

The Midwest ISO's unit commitment and dispatch follows a two day cycle, illustrated by the following typical Monday-Tuesday evolution:[21] On Monday morning, the Midwest ISO

(Continued…)

16 *See* RRM 12/29/03 Direct at 19:7-10.

17 *See* RRM 12/29/03 Direct at Exhibit RRM-1, pp. 15–16 (Figure RRM 1-2).

18 *Id.*

19 *See* RRM 7/7/05 Supp. Test. at 6:18–7:18, (Figures RRM-1, RRM-2).

20 *See* Additional Supplemental Testimony of Ronald R. McNamara, filed March 3, 2005 ("RRM 3/3/05 Supp. Test."), at 10:16-19.

21 *See generally* RRM 9/29/04 Direct at 13:13–14:6; *see also* Open Access Transmission and Energy Markets Tariff for the Midwest ISO, Module C, Transmission Provider Energy Markets, Scheduling and Congestion Management ("TEMT"), at pp. 470-71: Sec. 39.

accepts bids from load serving entities that wish to acquire their Tuesday requirements from the market ("load bids"). These bids determine the quantity of power that would be demanded at different prices, *i.e.*, the demand curve. The Midwest ISO also accepts offers from generators willing to sell power on Tuesday. These offers are stacked from lowest to highest price and form the supply curve. In the absence of transmission congestion or transmission losses, the intersection of the supply and demand curves would reveal the price of power for Tuesday. At that intersection, the buyers are willing to pay at least that price for a quantity that the suppliers are willing to sell for no less than the same price.[22] The Midwest ISO also receives bilateral schedules[23] and self-schedules[24] for transmission service and virtual transactions.[25] The Midwest ISO then conducts a security-constrained unit commitment based on the offers and bids that it has received to optimize use of the transmission system and minimize costs.[26] Monday's activities in preparation for Tuesday are known as the day-ahead market.

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[22] Some buyers might have been willing to pay more; some sellers might have sold for less — but no buyer pays more than it is willing to pay, and no seller receives less than what it is willing to take. *See* Market-Clearing Hypothetical, attachment A hereto.

[23] Bilateral transactions schedules, also referred to as financial schedules or "finScheds," reflect bilateral agreements entered into outside of the Midwest ISO energy markets. *See* TEMT at p. 52: Sec. 1.21. As stated in the LGE-Midwest ISO joint stipulation filed December 7, 2004, these schedules allow the financial linking of generation to load and are settled only for congestion and losses through the Midwest ISO energy markets, whereas the energy portion of these agreements are settled between the parties per the terms of the bilateral agreement. Stipulation ¶ 14.

[24] Self-schedules are schedules in which the scheduling party indicates that it is willing to sell or buy a specified quantity of energy at any price as determined by the market. *See* TEMT at p. 122: Sec. 1.282. Self-scheduling parties are often referred to as "price takers." *Id.* at 473: Sec. 39.1.2.

[25] Virtual transactions are offers to sell or bids to buy energy that are not backed by "physical" assets to buy or sell actual energy. *See* TEMT at p. 140: Sec. 1.341. As such, virtual transactions are strictly financial positions and must be designated as such when offered or bid into the Midwest ISO energy markets.

[26] *Id.*; *see also* TEMT at p. 498: Sec.39.2.9.

At the close on Monday of the day-ahead energy market for Tuesday, the Midwest ISO "clears the market" by matching all offered supply to all bid-in demand in the most reliable and economic manner.[27] The clearing of the day-ahead energy market creates locational marginal prices ("LMPs") for energy, congestion, and losses at each commercial node[28] using a dispatch algorithm that optimizes all inputs to arrive at the most reliable, least-cost dispatch of generation resources to load.[29] Once the LMP matrix is developed, the supply, load, and transmission schedules are accepted and become financially binding.[30] In other words, if a supplier has offered to provide 100 MWh of generation to the market on Tuesday at a price of $30/MWh, it will be entitled to receive $3,000, but obligated to provide 100 MWh of energy. Similarly, if the day-ahead LMP is $30/MWh for a load zone, and the load bid is 100 MWh of demand, load will be entitled to receive 100 MW for an hour for $3,000 even if the actual, real-time price on Tuesday turns out to be $50/MWh. To the extent that a market participant does not meet its day-ahead financial commitment to buy or sell energy in real time, it will pay the real-time LMP (as discussed below) for any incremental change between its day-ahead financial commitment and the actual injection or withdrawal of energy from the transmission system.[31] For example, in the case of a generator that offered 100 MW in the day-ahead market for a certain hour and cleared all 100 MW at $30/MWh and therefore created a $3,000 financial obligation, the generator would be required to purchase 100 MW in the real-time market if it chose not to produce the 100

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[27] *Id.* at p. 498: Sec. 39.2.9.

[28] A commercial node is an electrical location on the transmission grid at which energy can be injected or withdrawn and at which a price for such energy is calculated. *See also* TEMT at p. 55: Sec. 1.33.

[29] TEMT at p. 500: Sec. 39.2.9.b.

[30] *See generally id.* at p. 510: Sec. 39.3.

[31] *Id.* at p. 576: Sec. 40.3.3.a.i.

MW sold in the day-ahead market. The real-time LMP price at which the generator would purchase the 100 MW may be higher or lower than the $30/MWh LMP price settled in the day-ahead market.

It is rare that all low-cost power can reach all load centers without exceeding the limits of the transmission system. As a result, the security-constrained economic dispatch algorithm may require certain higher-cost generation resources be used to serve load, rather than a cheaper generation resource, in order to ensure that the transmission system is operated within its limits.[32] Altering generation commitment and dispatch schedules to reflect the existence of transmission constraints is the "security constrained unit commitment and economic dispatch" function provided by the Midwest ISO.[33] The different prices in various regions resulting from the security-constrained dispatch of generation establishes Locational Marginal Prices ("LMPs"), and the difference between LMPs reflects the cost of congestion on the transmission system and of replacing transmission losses.[34] Thus, if the input price of generation offered into Louisville was $25/MWh and the price at the Cinergy Hub was $35/MWh, the congestion cost and the cost of replacing transmission losses associated with moving power from Louisville to the Cinergy Hub would be $10/MWh. Load in Louisville, however, would be charged the $25/MWh input-price LMP for extractions.

After the close of the day-ahead energy market, all generation resources that have cleared in the market are identified and provided as an input to the forward reliability assessment commitment ("RAC") process, which commits generation resources to provide energy at real

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[32] *See generally* RRM 9/29/04 Direct at 13:18–14:6.

[33] *Id.*

[34] *Id.*

time based upon a forecast demand curve.[35] The forward RAC process marks the first "physical commitment" of generation resources for real-time load.[36] All generation resources committed in the forward RAC are guaranteed recovery of their offers, which generally are referred to as the resources "costs," including start-up and production costs.[37] In the event that these generation resources are not able to recover their costs through LMPs over the commitment period, they are made whole through a revenue sufficiency guarantee payment ("RSG").[38] In order to fund RSG payments to generators, RSG charges are collected from load.[39] RSG charges are levied first on a localized basis in which a determination is made as to whether a local issue caused resources to be committed in the RAC, and then on a footprint-wide basis when no direct local issue can be identified as the cause of resource commitment.[40] Generation resources committed in the forward RAC are notified of their commitment and schedule for the real-time energy market by 8:00 P.M. on the day prior to the operating day (*i.e.*, real time).[41]

Events seldom unfold exactly as predicted, and this is particularly true in the electric service industry. Load may be higher or lower than forecast and some generation expected to be available may be rendered unavailable due to forced outages. Hence, on Tuesday, the Midwest

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[35] TEMT at p. 533-34: Sec. 40.1.2.a-d. As a general proposition, the sum of volumes cleared in the Day-Ahead market and scheduled transactions does not equal the forecasted load for the region for the next day. Accordingly, the Midwest ISO must have available to it additional generation to meet the difference between load cleared in the Day-Ahead market and forecasted load. The relationship between Day-Ahead cleared demand, forecasted load, and real-time actual load — updated at five-minute intervals — is available in graphic and table form at http://www.midwestmarket.org/page/Real-Time+Info.

[36] *See generally* TEMT at p. 530A: Sec. 40.1

[37] *Id.* at p. 565: Sec. 40.2.13.

[38] *Id.*

[39] *Id.* at pp. 577-78: Sec. 40.3.3.a.ii.

[40] *Id.*

[41] *Id.* at p. 534: Sec. 40.1.2.d.

ISO will accept offers from generation willing to supply power on a real-time basis to accommodate deviations between day-ahead schedules and actual power flows.[42] Like the day-ahead energy market, the Midwest ISO optimizes the dispatch of all available generation resources in the most reliable and economic manner taking into account day-ahead schedules, real-time offers and bids and constraints on the transmission system.[43] This optimization occurs on a five-minute basis, resulting in the Midwest ISO sending a dispatch signal to all generators every five minutes.[44] The resultant five-minute LMP prices of this optimization are integrated over each hour to produce an hourly, real-time LMP.[45] This LMP will be charged or credited to every market participant withdrawing or injecting energy into the transmission system in real time to the extent that the market participant does not have a corresponding day-ahead energy market schedule or to the incremental deviation amount in the event that the market participant deviates from its day-ahead energy market schedule.[46] By way of example, if a generator committed to supply 100 MWh in the day-ahead market, but can only produce 90 MWh on Tuesday, it will be charged the real-time LMP for the 10 MWh shortage. If load was bid in at 100 MWh, but was actually 90 MWh, it will be deemed to have sold 10 MWh into the real-time market at the real-time LMP.

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42 *See* TEMT at p. 543: Sec. 40.2.3.a.

43 *See generally id.* at pp. 470-71: Sec. 39.

44 *Id.* In real time, preliminary five-minute LMPs at each hub and selected nodes are posted to a Web site: http://www.midwestmarket.org/page/LMP+Contour+Map+&+Data. The LMP data are also presented on a color-coded map of the footprint, and compared to day-ahead data for the associated hour and to estimates of the last hour's real-time LMP.

45 TEMT

46 *Id.* at pp. 470-71: Sec. 39.

Real-time operations also allow the Midwest ISO to enhance system reliability while maximizing the efficient operation of the grid.[47] In the absence of regional real-time security-constrained economic dispatch, the primary tools available to a Reliability Coordinator to control flows are Transmission Loading Relief ("TLR") procedures, which interdict transactions that have an impact of 5% or greater on a congested interface.[48] TLRs are blunt and inefficient in four different ways:[49]

1. It is difficult to accurately predict the effect of curtailing transactions on a specific transmission facility or "flowgate" that is approaching its operating limit. When a transaction is curtailed, the parties to that transaction have choices to redispatch their own generators, curtail load, or reconfigure parts of the transmission system (*e.g.*, open a breaker) in response to the curtailment.[50] The parties to each of the curtailed transactions are free to develop a response to the TLR independently of one another and generally without specific direction from the reliability coordinator.[51] Since the reliability coordinator does not know what the new pattern of generation, load, and transmission configurations will be or its impact on the facility he is seeking to protect, TLRs frequently lead to under-utilization of the transmission system.[52] In 2003, flowgates in the portion of the Midwest ISO that includes LGE were under-utilized by an average of

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47 *See* RRM 9/29/04 Direct at 8:20-22, 16:3.

48 *See* Updated Supplemental Testimony of Roger C. Harszy, filed July 7, 2005 ("RCH 7/7/05 Supp. Test.") at 5:6-7; *see also* RRM 9/29/04 Direct at 6:15-17.

49 *See* RRM 9/29/04 Direct at 6:17-21.

50 *Id.* at 7:19-21.

51 *Id.* at 7:22-24.

52 *Id.* at 7:24–8:3.

9% of their capacity during level 3 and higher TLR events.[53] And, because curtailing transactions sometimes fails to produce the desired reduction in actual power flows, relying on TLRs may temporarily overload transmission facilities.[54]

2. TLRs often require 30 to 60 minutes to implement.[55] Given that TLRs are being implemented against a pattern of continuously changing load, generation, and power flows, they are at best a rough tool for maintaining system reliability.[56]

3. The transmission system is operated on a contingency basis. This means that flows over a specific transmission facility must be limited such that the facility could instantaneously accommodate the additional flows in the event that other facilities, which may be operated by other utilities, fail. Without coordinated economic dispatch and the panoramic transmission model that the Midwest ISO operates in real time, TLRs would have to be called based on forecasts of power flows over contingent facilities.[57] This can further compound the under-utilization of LGE transmission assets.[58]

4. TLRs curtail transmission schedules without reference to the economic value of the transactions being cut at the time of the curtailment.[59] While it is difficult to determine the economic impact of any given TLR in the absence of a market, there will be many instances in which a small redispatch of a generator close to a constraint could have

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53 *See* Rebuttal Testimony of Dr. Ronald R. McNamara filed November 19, 2004 ("RRM 11/19/04 Rebuttal") at 73.

54 *See generally* RRM 12/29/03 Direct at 14:21-26.

55 *See* RCH 7/7/05 Supp. Test. at 9:5-7.

56 *See* RRM 12/29/03 Direct at 13:10-14.

57 *See e.g., id.* at 16–17.

58 *See, e.g.*, RRM 12/29/03 Direct at 16.

59 *See* RRM 9/29/04 Direct at 6:18-21.

relieved that constraint at a much lower cost than a TLR which rations transmission capability by curtailing transactions on a pro rata basis.[60]

By coordinating the dispatch of all of the generators within its footprint on five-minute intervals in real time, the Midwest ISO has sharply reduced the need to physically interrupt scheduled transactions of Midwest ISO member companies through the issuance of TLR orders.[61] However, real-time redispatch is effective in reducing TLRs only for transactions that source and sink within the Midwest ISO.[62] Transactions that source or sink outside the Midwest ISO footprint continue to have to be controlled through the TLR process.[63]

The market is a convenience; it is not a mandate.[64] Vertically-integrated utilities that want to dedicate their own generation to their own load may continue to do so. A utility has the option to submit a "self-schedule" by advising the Midwest ISO that it will produce power from its facilities to meet its native load and need not submit a price bid or depend upon being committed in either the day-ahead or real-time markets to produce power.[65] Injections into the grid will be assigned the LMP where the generation is located and extractions will be valued at the load location.[66] Alternatively, a utility may submit a financial schedule that arranges transmission of power from its resource to its load to be settled at the price of the energy determined by the utility. Although self-schedules and financial schedules are charged the cost of congestion and losses, market participants in the Midwest ISO have been allocated Financial

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60 *See* RRM 12/29/03 Direct at 12-17; RRM 9/29/04 Direct at 6–10; *see also* RCH 7/7/05 Supp. Test. at 4-6.

61 *Id.* at 9:6-11, 14-15.

62 *Id.* at 9:16-18.

63 *Id.*

64 *Id.* at 15:17-21.

65 TEMT at p. 473: Sec. 39.1.2.

66 *See* RRM 11/19/04 Rebuttal at 22:1-8.

Transmission Rights ("FTR") consistent with their nominations that entitle them to receive congestion revenues over designated transmission paths.[67] Thus, most if not all of the congestion charges are returned through FTR payments.[68]

Self-schedules are, however, inefficient since at any given time power may be available to load at a lower cost than the utility's generation, or the LMP for additional generation may be higher than the its cost of production.[69] In either case, the utility would profit from lower costs of supply or higher margins on generation (which, of course, will be flowed through to the utility's customers).[70] LGE's inclusion in the Midwest ISO makes transparent to this Commission the cost associated with self-scheduling.[71] Indeed, it is precisely because market operations are more efficient that LGE does not self-schedule, but instead submits supply offers and load bids into the day-ahead market. Although he acknowledged that LGE had the option to self-schedule, Mr. Gallus explained:[72]

> [T]he way the market is designed, it's to our economic advantage generally to make the units available economically so that, if the market price turns out to be less than our cost of generation, our units are not committed to the market, and we're buying energy from somebody else's lower-cost resources. That's the same thing we did prior to Day 2 except now its centralized and its really kind of automated through MISO.

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67 *Id.* at 24:13-20.

68 *Id.* at 25:3-5. Self-schedules are also charged for marginal losses, but most of these charges are rebated. A utility will incur charges for loss irrespective of whether (a) it is in the Midwest ISO or operating as a stand-alone company or (b) the context is Day 1 or Day 2 operations. *Id.* at 22:20–23:6.

69 *See generally* RRM 9/29/04 Direct at 14:21–15:7.

70 *Id.*

71 *See* RRM 9/29/04 Direct at 14:13-17; RRM 7/7/05 Supp. Test. at 7:14-18.

72 2 T.E. 15:14–16:1. Reference herein to the July 2005 hearing transcript will be to the volume number followed by "T.E." and a pinpoint cite where applicable.

II. The Results Are In and the Results Are Favorable.

A. The Favorable Direction of Results Projected in the Midwest ISO Modeling has been Confirmed.

Since the inception of this inquiry, this proceeding has been characterized by dueling models. Dr. Morey and other witnesses on behalf of LGE presented results from a patchwork of models that produced the result for which Dr. Morey was paid.[73] LGE's modeling was inherently flawed in that it purported to demonstrate the impact of stand-alone versus regional operation of the transmission system with models that included no representation of the transmission facilities in LGE or in any other control area. The impact of regional transmission flows on LGE internal operations was not represented at all.[74] The effect of LGE's entire modeling effort was to obfuscate the issues at stake in this proceeding. One cannot model the benefits of regional versus stand-alone operation of the transmission system and management of congestion with models that do not represent transmission facilities and how the security limits and contingencies for those facilities constrain power flows.

Dr. McNamara, on the other hand, presented much more detailed modeling results demonstrating that withdrawing from the Midwest ISO would impose large net costs on LGE and its customers.[75] Although Dr. McNamara's initial modeling runs used input data which had

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73 *See, e.g.,* Additional Supplemental Rebuttal Testimony of Mathew J. Morey, filed April 1, 2005 ("MJM 4/1/05 Supp. Rebuttal"); Supplemental Rebuttal Testimony of Mathew J. Morey, filed January 10, 2005 ("MJM 1/10/05 Supp. Rebuttal"); Supplemental Testimony of Mathew J. Morey, filed September 29, 2004 ("MJM 9/29/04 Supp. Test.").

74 *See* RRM 11/19/04 Rebuttal at 78–81; RRM 3/3/05 Supp. Test. at 16–19.

75 *See, e.g.,* RRM 7/7/05 Supp. Test.; RRM 3/3/05 Supp. Test. For a description of the Midwest ISO's modeling methodology, *see generally* Additional Supplemental Testimony of Ronald R. McNamara, filed February 21, 2005 ("RRM 2/21/05 Supp. Test."); Testimony of Ronald R. McNamara, filed January 20, 2005 (RRM 1/20/05 Test."); Supplemental Rebuttal Testimony of Ronald R. McNamara, filed January 20, 2005 (RRM 1/20/05 Supp. Rebuttal"); RRM 11/19/04 Rebuttal.

been vetted by LGE for accuracy, but turned out to be in error, there were no material differences between the principal model inputs used in LGE's modeling and those used for Dr. McNamara's final model runs.[76] The primary difference between Dr. McNamara's and LGE's models is the failure of LGE's models to represent the operation of the transmission system – the very issue which is the focus of this proceeding. In any given month, actual loads and generation may be different from the expected values used in modeling. Thus, modeling does not provide precise point forecasts. It provides insights and directionally significant trends which can be compared to indicators of actual market operations. For example, economic models are used to predict changes in Gross Domestic Product, but they are not relied upon to forecast the closing value of the Dow Jones Industrial Average on a given date three years in the future.

Fortunately, the Commission now has actual data with which to work. That data supports the direction indicated in the model generated by the Midwest ISO. The Day 2 markets began on April 1, 2005, and despite predictions to the contrary, they have been working pretty much as designed ever since. As expected, they are revealing transparent day-ahead and real-time prices.

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[76] *See generally* RRM 3/3/05 Supp. Test. While the two sets of models relied on comparable load, fuel, and generation inputs for LGE, the models, as previously discussed, differed in their representation of the transmission system. The other significant differences are that LGE: (1) made significant errors in representing loads on nearby utility systems with which they appear to have been unfamiliar (*see* RRM 3/3/05 Supp. Test. at 20–22); (2) arbitrarily increased the prices coming out of their MIDAS with a "scarcity" adjustment despite the existence of ample capacity (*id.* at 19–20); and, (3) inappropriately modeled bilateral purchases and sales as though they would achieve the same cost savings as centralized economic dispatch (*see* RRM 11/19/04 Rebuttal at 82–84). Even if one were to overlook its obvious problems, the only point made by LGE's modeling would be that if the future of generation dispatch, off-system sales, and prices with regional economic dispatch and congestion management were just like the past without the Midwest ISO providing economic dispatch and congestion management, LGE would be better off not paying for Midwest ISO services. It thus fails to address the purpose of this proceeding: to evaluate the benefits of Midwest ISO services to Kentucky consumers.

They are showing where congestion occurs, valuing that congestion, and distributing revenues pursuant to FTRs.

Although the Commission has initial data from only the first months of market operations, the data are confirming key insights and indicators forecast in Midwest ISO modeling. For example:

- The Midwest ISO's modeling identified that transmission within LGE would be constrained such that the value of electricity in the eastern portion of LGE's system would in some hours be significantly higher than the price of electricity at LGE's Louisville load center. That has occurred.[77]

- Dr. McNamara's modeling reflected the fact that given regional security-constrained economic dispatch, LGE would be able to more fully use its transmission assets. This finding has been reflected in lower actual curtailments of LGE transactions since the start of the market.[78]

- The Midwest ISO's model forecast that LGE would be able to increase its off-system sales and obtain higher prices for its power within a large integrated regional power market. That is exactly what has occurred. LGE has enjoyed large returns on its off-system sales in the first three months of the market despite the fact that up to 500 MW of capacity that would have been dispatched at the Brown power plant was unavailable for much of that period.[79]

Dr. McNamara's modeling showed that LGE would benefit from their participation in the Midwest ISO. Actual results of the market are confirming that conclusion.

B. Actual Market Data Shows Substantial Benefits to LGE.

Actual market operations over three months (April-June, 2005) show that LGE enjoyed the following financial results from revenue sources:

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77 *See, e.g.,* RRM 7/7/05 Supp. Test. at 6:18–8:5.

78 *Id.*

79 *See* 1 T.E. 93:20-22.

Day-Ahead Revenue (net of congestion and losses)	$-1,409,000
Real-Time Revenue (net of congestion and losses)	10,729,000
Over-Collected Losses	7,153,000
Revenue Security Guarantee Payments	15,789,000
FTR Revenues	6,111,000
Uninstructed Deviation Payments	310,000
Net Inadvertent Compensation	497,000
Total	**$39,180,000**

Against these revenue sources, LGE was billed for costs of Midwest ISO operations, reliability related expenses and revenue neutrality obligations[80] as follows:

Market Administration Fees	$ 1,722,000	
Revenue Security Guarantee Obligations	4,745,000	
Uplift [Revenue Inadequacy?]	7,469,000	
Penalties	154,000	
Total	**$14,090,000**	
Net Revenue		**$25,090,000**[81]

As Mr. Gallus notes, it is impracticable to predict the future based on three months of data.[82] Nevertheless, as Dr. McNamara observed, the actual data, just like models, provide directional indices and provide an objective measure against which the assumption underlying

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80 As Dr. McNamara explained at the hearing, revenue neutrality obligations arise because the revenue entitlements of the Midwest ISO do not always precisely match its payment obligations under the tariff. *See* 1 T.E. 65:2-23. Where payment obligations exceed revenue, the Midwest ISO recovers the shortfall through uplift. Currently, most uplift is associated with the fact that, pursuant to FERC compliance requirements, the Midwest ISO is over-reimbursing for losses — which corresponds to LGE's healthy revenue for "Over-Collected Losses." *See* 1 T.E. 63:7-11.

81 LG&E/KU Cross Exh. No. 4 (attachment B hereto) contains a $50 million computational error, showing a "total charges/revenues" of $25,140,000.

82 *See* Additional Supplemental Direct Testimony of Martyn Gallus, filed July 7, 2005 ("MG 7/7/05 Direct") at 11:9-13.

the models may be tested.[83] Preliminary market results indicate that LGE will do quite well in the markets and that the long-term revenues therefrom will vastly eclipse the cost of membership in the Midwest ISO.

C. LGE's Portrayal of Market Data is Skewed, Incomplete and Misleading.

In his Additional Supplemental Direct Testimony, filed July 7, 2005, Mr. Gallus posits that the Day 2 modeling of the Midwest ISO is unreliable because several cost items billed through the market settlement process were substantially higher than predicted.[84] Mr. Gallus, however, reports only costs and overlooks corresponding revenue that has resulted in the <u>net</u> profit to LGE.[85] Even for some putative "costs," the figures in his testimony cannot be reconciled with the actual invoice data that LGE entered into evidence as its cross-examination Exhibit No. 4.[86]

In Table 2 of his Additional Supplemental Direct Testimony, Mr. Gallus reports a monthly average of $2,407,000 in "uplift" cost.[87] He compares this to $172,000 of uplift projected by the Midwest ISO in its studies. Mr. Gallus fails to mention that LGE received $15,789,00 in RSG payments in April through June and $7,153,000 for over-collected losses, which are the categories of expense that make up the bulk of "uplift."[88] He further fails to note that a substantial amount of "uplift" experienced by the Midwest ISO was caused by forced

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[83] *See* 1 T.E. 44:12-24; 45:5-17.

[84] *See* MG 7/7/05 Direct at 3:1-2; 6:1-8. Mr. Gallus also ignores that actual "Administrative Costs (Schedule 10, 16, and 17 billings) were significantly lower than predicted in LGE's 2004 study. *See* MG 7/7/05 Direct at 4 (Table 1); 9 (Table 3).

[85] *See* 1 T.E. 62:10-19.

[86] A copy of 7/05 Hearing LG&E/KU Cross Exh. No. 4 is attachment B hereto.

[87] MG 7/7/05 Direct at 5 (Table 2). This figure cannot be reconciled with sums set forth on LGE Cross Exh. No. 4.

[88] *See* LGE Cross Exh. No. 4.

outages in LGE's system, the cost of which would have been fully borne by LGE but for the support of the Midwest ISO.[89] As it was, LGE actually profited from "uplift" to the tune of $11,087,000 over the course of three months.

Mr. Gallus testifies that LGE experienced net congestion revenue of -$367,000 per month.[90] This figure, however, cannot be derived from LGE's own data and is in fact contrary to reported financial results. As set forth in LGE's cross-examination Exhibit No. 4, LGE in fact received $10,729,000 from the real-time market in the first three months of operation after congestion costs and losses had been netted. In the first two months of operation, LGE earned an average of $386,000 per month in the day-ahead market after congestion and losses had been netted. In June, LGE overbid load in the day-ahead market by a significant amount and suffered a loss of $8,362,000, leaving a three-month net loss in the day-ahead energy market of $1,409,000. However, LGE collected $6,111,000 in FTR revenue. In total, LGE was $15,431,000 ahead in the energy markets after congestion costs and losses were netted against market and FTR revenues.

In improper sur-direct testimony,[91] Mr. Gallus attempted to minimize the impact of LGE's net three-month gain of $25 million from the Day 2 market by claiming that those revenues do not reflect the cost of production which he stated, without support, to be $24 million over the relevant period.[92] Accordingly, Mr. Gallus testified that LGE's actual revenue from the Midwest ISO's markets for three months was only $1 million.[93] However, Mr. Gallus' sur-direct

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[89] *See* 1 T.E. 191:17–18:9.

[90] *See* MG 7/7/05 Direct at 5 (Table 2); 7:1-3.

[91] 1 T.E. 232-40.

[92] 1 T.E. 236:15-17.

[93] 1 T.E. 241:13-17.

testimony cannot be squared with either his Additional Supplemental Direct Testimony or the LGE's response to post-hearing data requests. In his prepared Additional Supplemental Direct Testimony, Mr. Gallus noted that LGE was able to realize an average margin of $17.45/MWh on 291,528 MWh of off-system sales in two months.[94] By any convention, a "margin" is the difference between the cost of production and the sales price received. Extrapolating LGE's sales volumes to three months indicates volumes of 437,292 MWh, for net revenues of $7,630,745. In fact, Mr. Gallus reports $10,166,000 in off-system sales profits for April and May,[95] which translates into profits of $15,249,000 if extrapolated to three months.

LGE's response to post-hearing data requests paints an even more robust profit margin on off-system sales. Actual data for the first three months of the Day 2 markets show off-system sales of 849,374 MWh.[96] On those volumes, LGE received $47,624,000[97] in gross revenue, which was offset by production cost of $23,960,000.[98] Thus, LGE's actual margin for off-system sales was $23,664,000 for three months, which if extrapolated for a full year of operations will produce $94,656,000 of pure profit to LGE through participation in the Midwest ISO's Day 2 markets from off-system sales alone.[99]

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94 *See* MG 7/7/05 Direct at 8:18-20.

95 *See* MG 7/7/05 Direct at 4 (Table 1), 9 (Table 3).

96 LGE's Response to Post-Hearing Data Request of the Commission Staff ("LGE 8/5/05 Responses") No. 2, p.1 (Table 1).

97 LGE 8/5/05 Responses No. 2, p.2 (Table 2). In 2004 testimony, Mr. Gallus predicted that margins on off-system sales would fall under Day 2 operations. Supplemental Testimony of Martyn Gallus, filed September 29, 2004 ("MG 9/29/04 Supp. Test.") at 4:9-12.

98 LGE 8/5/05 Responses No. 2, p.2 (Table 3).

99 The Midwest ISO's settlement system automatically nets revenues from service to native load as LGE receives the prevailing LMPs for its injections but is charged the applicable LMP (which embodies at least the cost of congestion) for withdrawals to serve native load. *See* RRM 11/19/04 Rebuttal at 22:1-8.

In addition, Mr. Gallus, while conceding that LGE may self-schedule, and thus maintain the fictitious physical link[100] between resources and customers, contends that LGE is nevertheless prejudiced under the TEMT because it must pay congestion charges.[101] The fact is, however, that the TEMT did not create congestion.[102] Congestion has existed on LGE's facilities well before the advent of Day 2 markets. The Midwest ISO's markets, however, quantify the marginal cost of the congestion in order that the true cost or value of resource selections is transparently revealed. Through FTRs, the difference between the marginal cost of congestion and the actual cost of redirects is returned to LGE leaving it in a position equal to their circumstances under Day 1 operations.[103] Furthermore, Mr. Gallus concedes that LGE bore the cost of start-up and no load operations in Day 1 and would continue to bear such costs if operated as a Transmission Operations-Reliability Coordinator.[104] As a market participant in Day 2, however, LGE is guaranteed recovery of its cost of start-up and no load operations if its units are committed in the RAC process.[105]

Mr. Gallus takes issue with the fact that LGE will have to acquire power from the real-time markets and bear RAC revenue sufficiency guarantee charges if it deviates from its day-

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100 After LGE's integration into the Eastern Interconnection several decades ago, there has not been a direct physical connection between resources and load. The output of LGE resources follows the path of least resistance, which may or may not be to the LGE load. The Day 2 Market has not altered this law of physics. *See* Supplemental Rebuttal Testimony of Michael S. Beer, filed January 10, 2005 ("MSB 1/10/05 Supp. Rebuttal") at 3:6-8.

101 *See* MG 9/29/04 Supp. Test. at 11:22–12:3, 15-18.

102 *See* RRM 11/19/04 Rebuttal at 41:1-10.

103 *See* RRM 11/19/04 Rebuttal at 22:20-22.

104 *See* MG 9/29/04 Supp. Test. at 15:16-18.

105 TEMT at p. 565: Sec. 40.2.13.

ahead schedules.[106] These are the same risks that LGE faced in Day 1 and would similarly face as a Transmission Operations-Reliability Coordinator. A positive deviation between scheduled generation and native load means that the increment of higher demand must be served by third-party power. Traditionally, deviations were supplied through interchange agreements with neighboring utilities based upon rigid cost formulas. Alternatively, utilities could meet shortage deviations by placing phone calls to see who had excess power at the lowest cost. Utilities were not, however, allowed to simply "lean" on the grid by taking power to meet shortfalls without paying for it. The real-time market simply meets this shortfall by matching the load with available generation in the most reliable and economic manner, at a price that is transparent to all market participants. LGE will be exposed to RSG charges for deviations, but the charges to supply power from the lowest-cost generation in the region capable of doing so undoubtedly will be less than the cost LGE would incur to keep a unit in spin to self-supply real-time deviations.

Mr. Gallus suggests that the market is not working properly because high cost peaking units are being dispatched when the LMP is below their production costs.[107] Mr. Gallus, however, confuses economic dispatch with unit commitment and dispatch to maintain system reliability. Units committed in the RAC process do not set the day-ahead LMP and are kept available to ensure system reliability and therefore may be taken out of "economic merit order." If the operators at the Midwest ISO detect the emergence of a circumstance that may threaten grid security, *e.g.*, a line failure, they may dispatch a unit committed in the RAC process, irrespective of price, because it supports the grid in a particular location. Sometimes, potential reliability threats do not materialize and units committed and dispatched on a prophylactic basis

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[106] *See* Supplemental Rebuttal Testimony of Martyn Gallus, filed January 10, 2005 ("MG 1/10/05 Supp. Rebuttal") at 11:14-18.

[107] *See* MG 7/7/05 Direct at 13:3-6.

are quickly returned to a standby mode. These activities may appear to be unusual to participants that lack the region-wide view of the Midwest ISO. They are, however, necessary and proper to maintaining the integrity of the grid. Finally, Mr. Gallus claims that Kentucky customers will be prejudiced by the fact that the Midwest ISO has no obligation to serve, unlike LGE's obligation under state law.[108] The Midwest ISO has a duty to maintain the reliability of the grid, which means ensuring that power flows to all load requirements. Given the Midwest ISO's superior capability to requite this obligation, Kentucky customers actually enjoy a greater expectancy of adequate service than that provided by the LGE's "best efforts" obligation to serve.

The fact of the matter in this case is that LGE sees a value both in the markets that the Midwest ISO has established and in its multiple tools available to promote and ensure reliability. Mr. Gallus confirmed that even if LGE were to withdraw as a member of the Midwest ISO, it still intends to make sales into, and purchases from, the Midwest ISO's Day 2 market.[109] Similarly, while LGE cites the availability of TVA or SPP as a Reliability Coordinator, it acknowledges that either organization would be dependent on information provided by the Midwest ISO, and the coordination agreements developed by the Midwest ISO with PJM, TVA and SPP, to perform adequately. It does not, nor could it, credibly argue that either TVA or SPP would provide day-to-day and minute-to-minute services for transmission operations that are equivalent to what LGE receives from the Midwest ISO. What LGE wants is to enjoy the benefits of the Midwest ISO's efforts and capabilities without having to pay for them on the

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[108] *See* MG 1/10/05 Supp. Rebuttal at 4:17-19.

[109] *See* MG 9/29/04 Supp. Test. at 20: 3-5.

same basis as other participants in the region.[110] It is tautological that LGE would save money if they received the benefits of the Midwest ISO's markets and its reliability capabilities for free. The free-rider phenomenon is, however, the scourge of the electric service industry and a major contributor to the relatively weak infrastructure that currently exists. While trying to get something for nothing may be a short-term, profit maximizing expedient, it is bad public policy in the long term.[111]

The evidence in this case shows that the Day 2 transmission operations produce efficiency gains and that the Midwest ISO's reliability coordinator capabilities are second to none. These benefits inure to LGE and its customers, and it is only fair, and in the public interest, that LGE pays its fair share of the costs necessary to create these benefits.

III. The Day 2 Transmission Operations Have Significantly Mitigated the Economic Impact of TLRs.

Mr. Johnson cites the incidence of 147 TLRs posted in May 2005 as evidence that the Midwest ISO's Day 2 operations have failed to displace TLRs with regional dispatch.[112] This claim is both misleading and fails to account for the drastic change in the economic effects of TLRs in Day 2.

As Mr. Harszy testified, most of the TLRs issued in May of 2005 related to flows passing through the footprint of the Midwest ISO, and not flows that originated and sank within the

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110 Mr. Gallus testified that if LGE was out of the Midwest ISO, it would only pay Schedules 16 and 17 charges associated with off-system sales, whereas all other participants pay such fees for total injections and withdrawals. 2 T.E. 10:12-20.

111 *See* Supreme Court nominee Judge Roberts' opinion in *Midwest ISO Transmission System Owners v. FERC*, 373 F.3d 1361 (D.C. Cir. 2004).

112 *See* Additional Supplemental Direct Testimony of Mark S. Johnson, filed July 7, 2005 ("MSJ 7/7/05 Direct") at 3:18-19.

geographic scope of the Midwest ISO.[113] Of particular note, Mr. Harszy explained that under the Joint Operating Agreement ("JOA") that the Midwest ISO has in place with PJM, the Midwest ISO has the right to control PJM loop flows to a zero impact on Midwest ISO flowgates.[114] This right is particularly important to LGE given the very heavy flows occurring between Commonwealth Edison (PJM West, American Electric Power, and Dominion Energy) and the classic PJM footprint. Without this degree of control, Mr. Harszy testified that LGE's service territory would be overwhelmed by PJM-related loopflows.[115] The enforcement mechanism under the JOA is the issuance of TLRs to keep flows within prescribed allocations, which account for most of the May 2005 TLRs. The Midwest ISO would have no obligation or reason to enforce the JOA to eliminate loopflows affecting LGE if it is no longer a member of the Midwest ISO.

The TLRs issued in the LGE service territory in May 2005 were associated with multiple forced outages experienced by LGE with respect to its Brown generating facility involving over 500 MW of capacity.[116] With this facility in service, the Midwest ISO would have been able to manage congestion through LMP driven redispatch. With a critical facility down, however, TLRs were necessary to maintain system integrity. LGE should not, therefore, be heard to criticize the Midwest ISO for taking action to alleviate a reliability problem of its own making.

Finally, and devastatingly, Mr. Harszy testified as to the economic effect of TLRs under Day 1 and Day 2 market operations.[117] In the period of April through June, 2004, the Midwest

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[113] 1 T.E. 188:11-25; 189:12-19.
[114] *Id.* at 195:8–198:15.
[115] *Id.* at 198:6-15.
[116] *See* 1 T.E. 93:20-22, 191–92.
[117] 1 T.E. 189–91.

ISO issued TLRs affecting 127 LGE transactions, which had the effect of curtailing 13,239 MWh of exports and 2,492 MWh of imports.[118] During the same period in Day 2, the Midwest ISO issued a single TLR applicable to one LGE transaction that interrupted only 450 MWh of imports.[119] As Mr. Harszy testified, it is the absence of economically constraining TLRs, as opposed to decreased native load, that explains LGE's phenomenal off-system sales experience over the first three months of the Midwest ISO's Day 2 markets.[120]

Mr. Johnson also suggests that security constrained economic dispatch is inadequate because the Midwest ISO has manually redispatched units on a "pre-emergency" basis in Day 2.[121] Operational issues as opposed to market flaws necessitated the manual redispatch. With the systemic failure at the Brown generating facility, the Louisville area faced profound voltage stabilization issues. With its forward-looking, regional view of reliability, the Midwest ISO was able to predict the voltage stability issue (*i.e.*, on a "pre-emergency" basis) and manually redispatch the system to avoid a full-fledged reliability issue. The Midwest ISO brought the manual dispatch procedure to the attention of NERC, which found that its use by the Midwest ISO was wholly in accord with NERC rules and indeed represented a proactive response to a potentially serious problem.[122] Indeed, NERC found the actions of the Midwest ISO to be "best practices" that should be shared with and incorporated into the procedures of other reliability

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[118] Midwest ISO Redirect Exh. No.1, a copy of which is attachment C hereto.

[119] *Id.*

[120] 1 T.E. 190:4–191:11.

[121] *See* MSJ 7/7/05 Direct at 3:19–4:2.

[122] 1 T.E. 199:12-25; Letter dated July 11, 2005, from Larry Kezele, Manager, Operating Reliability and Market Services, NERC, 7/05 Hearing Midwest ISO Redirect Exhibit 2, at 2 (describing the manual redispatch procedure as "a proactive procedure to manage transmission congestion").

coordinators.[123] Proactive measures to ensure reliability and overcome a company-induced stability problem should be the subject of praise, or at least grudging respect, as opposed to condemnation.

To the extent that the instant inquiry is whether LGE would be better off in another transmission organization, it should be borne in mind that the only tool available to either TVA or SPP as a reliability coordinator is the TLR process.[124] While the Midwest ISO and PJM have agreed to share data with these organizations, and thus improve their regional view, neither TVA nor SPP can balance the systems for which they provide reliability coordination through a process of security constrained dispatch. Neither of these organizations has an agreement with PJM reducing loopflow to zero.[125] Neither organization has the capability or authority to redispatch generation to promote efficient transactions.[126] Instead, both TVA and SPP rely exclusively on TLRs, and would so control LGE's system if either were chosen as a replacement Reliability Coordinator. Even without the new PJM flows, this would return LGE to circumstances in which 15,000 MWh of export transactions could be curtailed within a three-month period. Taking account of the PJM loopflows, the TLR situation could be markedly worse.[127]

IV. LGE May Experience Adverse Regulatory Consequences if it Withdraws From the Midwest ISO.

The record is clear that LGE was among the original founding members of the Midwest ISO and voluntarily committed to remain members to mitigate the market power arising from

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[123] 1 T.E. 200:2-6.

[124] *Id.* at 193:1-18; 194:13-14, 24-25; 195:1.

[125] *Id.* at 194:15-23.

[126] 1 T.E. 194:15-23

[127] *Id.* at 194:17–197:12.

their merger. Based on this uncoerced commitment, FERC made continued membership in an RTO a condition to its approval of the companies' merger. The question now at bar is whether the FERC would permit the companies to renounce their merger obligation without penalty because the RTO they helped form turned out different than they intended.

Mr. Beer testifies that FERC's views on RTO membership have changed substantially over recent years such that FERC would not make joining another RTO a condition of withdrawal from the Midwest ISO.[128] He cites the merger of CP&L and Florida Progress Corporation that was approved by FERC without enforcing the companies' commitment to join as an example of the FERC's relaxed attitude. This situation, however, is inapposite inasmuch as there is no RTO in Florida.[129] It is likely that FERC would take a far different view in the context of companies that are in a fully operational RTO that want to renounce an existing voluntary commitment for their own corporate gain.

Similarly, whatever flexibility the FERC now shows with respect to RTO <u>formation</u> is irrelevant to the structure of an <u>existing</u> RTO. FERC has approved of Independent Coordinator of Transmission proposals and limited-function RTOs for regions in which parties could not voluntarily agree on the establishment of a fully functional Order No. 2000 RTO.[130] The Midwest, however, is not such a region. The Midwest ISO operates Day 2 markets because FERC ordered it to do so.[131] The markets are working, and the FERC is not likely to be

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[128] *See* Additional Supplemental Rebuttal Testimony of Michael S. Beer, filed April 1, 2005 ("MSB 4/1/05 Supp. Rebuttal"), at 2:1-18.

[129] FERC terminated the GridSouth RTO proceeding because the sponsors could not surmount organizational challenges, not because it concluded that the proposed RTO was not cost effective. *See Regional Transmission Organizations*, 109 FERC ¶ 61,341 (2004).

[130] *Entergy Services Inc.*, 110 FERC ¶ 61,295 (2005).

[131] *Midwest Independent Transmission System Operator, Inc.*, 97 FERC ¶ 61,326 (2001).

sympathetic to an entity that simply does not share the FERC appreciation of efficient wholesale operation.

Mr. Beer testifies that there is no risk that FERC would rescind its market-based rate certification if the companies renege on their merger condition.[132] He states that Duke, which is not a member of an RTO, but which cannot pass market power screens nonetheless retains its market-based rate authority. Since the filing of Mr. Beer's testimony, several relevant events have transpired. On June 30, 2005, the FERC issued an order revoking Duke's market-based rate authority due to the existence of market power.[133] It did so even though Duke had not voluntarily accepted a merger condition. Moreover, Entergy and Xcel have voluntarily given up their market-based rate authority because they could not pass the FERC's market power screens.[134] Mr. Beer concedes that LGE cannot pass the FERC's market power screens in certain areas,[135] but goes on to speculate that FERC would not revoke the companies' market-based rate certificate as a result. The circumstances of Duke, Entergy and Xcel suggest that Mr. Beer's confidence is misplaced. Mr. Beer notes that LGE would reevaluate its request to withdraw from the Midwest ISO if the FERC revoked its market-based rate authority due to a violation of a

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132 *See* MSB 4/1/05 Supp. Rebuttal at 7:11-14.

133 *Duke Power*, 111 FERC ¶ 61,506 (2005).

134 Entergy recently submitted a filing to FERC stating its intention to revert to cost-based rates for power as a result of failing FERC's market-power screen and after FERC questioned whether Entergy's own "delivered price test," which showed no market power, were complete and fair. *See Entergy Services, Inc.*, Notice of Withdrawal of Request for Market-Based Rate Authority, Docket Nos. ER91-569-023, *et al.* (July 22, 2005).

135 *See* MSB 4/1/05 Supp. Rebuttal at 8:3-6. In its November 19, 2004 market power analysis, LGE cites its membership in the Midwest ISO as a factor undermining its ability to engage in anti-competitive conduct. *See LG&E/KU Market Power Analysis*, Docket Nos. ER94-1188, *et al.* (November 19, 2004).

merger condition.[136] Since it now appears likely that FERC would, at a minimum revoke LGE's market-based rate certificate, LGE may be putting this Commission through a great deal of effort in a useless exercise.

Mr. Beer's speculation that the FERC would allow it to withdraw from the Midwest ISO to form a TORC because the benefits of exiting MISO outweigh the costs is simply not supported by actual market outcomes. In three months alone, the companies recognized net benefits of $25 million through participation in the Midwest ISO's Day 2 markets. Moreover, the FERC is likely to take a dim view of an entity that fully intends to participate in the Midwest ISO's Day 2 markets but simply does not want to pay for the cost of its operation. Free-riding is a big enough problem in the industry without expecting FERC to act to exacerbate the situation.

Mr. Beer testifies that the planning and coordination function of the Midwest ISO constitutes a regulatory risk of remaining members of the Midwest ISO, speculating that the Midwest ISO may force LGE to build facilities that will benefit non-Kentucky consumers.[137] The Midwest ISO does not compel utilities to expand transmission facilities. Instead, through a partnership with utilities and state regulators, the Midwest ISO helps to identify regional transmission expansion opportunities that will improve reliability and relieve constraints.[138] As likely as not, the Midwest ISO may reveal out-of-state enhancements that will benefit Kentucky consumers. If the opportunity to make informed choices is perceived to be a risk by LGE, so be it, but it is not a risk that this Commission should rely upon to order LGE to withdraw from the Midwest ISO.

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[136] *See* MSB 4/1/05 Supp. Rebuttal at 9:21–10:2.

[137] *Id* at 6:7–7:4.

[138] *See An Assessment of Kentucky's Electric Generation, Transmission, and Distribution Needs*, Case No. 2005-00090, Comments of the Midwest Independent Transmission System Operator, Inc. (June 13, 2005).

Mr. Beer contends that membership in the Midwest ISO infringes on the jurisdiction of this Commission.[139] The Midwest ISO disagrees. This Commission continues to have full jurisdiction over retail rates and FERC has had exclusive jurisdiction over wholesale sales since 1935. Nothing about membership in the Midwest ISO or the operation of its Day 2 market affects this relationship. LGE remains free to submit transmission schedules for its native load transactions, in which case there is no sale to, or purchase from, a wholesale market as would affect the plenary jurisdiction of this Commission. With the efficiencies offered by the Day 2 market, LGE may choose to acquire more power from this market, but that is a voluntary choice by LGE and not an unavoidable result of the TEMT.

Indeed, the FERC has considered and rejected LGE's claim that the existence of the Day 2 market severs the link between load and company resources, or impairs the ability to reserve resources for the benefit of its customers:[140]

> Under the Midwest ISO proposal, load-serving entities may fully use DNRs [Designated Network Resources] to satisfy their must offer obligations through self-schedules and therefore can ensure that their DNRs are used to serve their respective customers during the Day-Ahead Market and scheduling process. A load-serving entity is only required to bid that portion of its DNR into the Day-Ahead Market that is in excess of its own needs.

Similarly, the FERC found that "[t]he RAC process in no way impairs LG&E's ability to use its resources to serve its load or exposes it to cost that it would not otherwise incur."[141]

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139 *See* Supplemental Rebuttal Testimony of Michael S. Beer, filed January 10, 2005 ("MSB 1/10/05 Supp. Rebuttal"), at 2:17–4:23.

140 *See Midwest Independent Transmission System Operator, Inc.*, 108 FERC ¶ 61,163 at P 411 (2004). As Mr. Raff noted, a refusal to submit a bid for available but unneeded capacity could constitute an exercise of market power intended to restrict supply and thereby increase price. 1 T.E. 182:19-25 (question); 183:21–184:8 (mechanisms discussed).

141 108 FERC ¶ 61,163 at P 528. Mr. Thompson was mistaken when he testified that LGE will be required to make its generation available to the Midwest ISO pool even if it wishes to use its generation resources solely to self-serve in-state load. See Supplemental Testimony of (Continued...)

The only jurisdictional blow recently inflicted upon the Commission has come at the hands of LGE and not from the Midwest ISO. Along with another jurisdictional utility, LGE initiated a challenge to KRS 278.214 alleging that the curtailment provisions therein were preempted by Federal law; *to wit*: the Midwest ISO Open Access Transmission Tariff ("OATT"). The Midwest ISO successfully defended the statute from the preemption challenge by showing that federal and state jurisdiction over curtailments operated in a complementary fashion.[142] As found by the court:[143]

> Defendant MISO, however, adamantly contends that no actual conflict exists between the state and federal provisions. Midwest ISO explains that the applicable OATTs govern the
>
> > terms and conditions under which customers like LG&E and KU take transmission service and does not direct that any transmission customer must react to a curtailment of its transactions without favoring captive customers who rely on it for bundled retail electric service.
>
> Thus, per MISO's explanation, FERC Order 888 and the applicable OATTs merely regulate how an RTO is to allocate curtailments of transmission service among its transmission customers such as Plaintiffs; nothing in the OATTs direct how Plaintiffs must allocate a reduction of their transmission service among the retail customers they serve.
>
> The Court agrees with MISO's construction.

LGE also challenged the state statute under the Commerce Clause, alleging that the provision purposefully discriminates in favor of local economic interests. LGE argued that the statute protected only customers within the certified territory of Kentucky utilities and thus "protects the reliability of electric service to Kentucky customers at the expense of out-of-state

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(Continued...)

Paul W. Thompson, filed September 29, 2004 ("PWT 9/29/04 Supp. Test.") at 3:5-12. The must-offer requirement is appplicable only to Designated Resources as described in the Stipulation between the Midwest ISO and LGE filed on December 7, 2004.

142 *Ky. Power Co. v. Huelsmann*, 352 F. Supp. 2d 777, 784 (E.D. Ky. 2005).

143 *Id.*

customers."[144] Here, LGE prevailed on its contention that the Commerce Clause "precludes a state from mandating that its residents be given a preferred right of access, over out-of-state consumers, to natural resources located within its borders or to the products derived therefrom."[145] It is in this context that the Commission should weigh the testimonies of Messrs. Thompson and Beer that LGE should be allowed to withdraw from the Midwest ISO because Day 2 markets do not give Kentucky customers preferred rights of access, over out-of-state consumers, to the low cost generation located in Kentucky. When it counts, they simply do not believe this and their testimony is incredible as compared to their actions.

Based upon this unsolicited challenge to the Commission's jurisdiction, and the establishment of the principle that it is unlawful to give preference to the interest of Kentucky consumers, it is more than passingly ironic that LGE here complains that its membership in the Midwest ISO somehow interferes with this Commission's ability to accord special protections to Kentucky consumers.

V. LGE Has Not Presented the Commission with a Viable Alternative to Participation in the Midwest ISO.

The Midwest ISO operates more than 100,000 miles of transmission facilities for 28 member transmission owners in 15 states and the province of Manitoba.[146] The Midwest ISO operates in real time the most sophisticated transmission network model in the industry for tracking and forecasting regional power flows. It commits and dispatches up to 131,000 MW of generating capacity. And, it operates regional energy markets for an area that covers 1.1 million square miles.

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[144] *Id.* at 784–85.
[145] *Id.* at 786.
[146] *See generally,* "About MISO" <http://www.midwestmarket.org/page/About MISO>.

LGE has not presented testimony describing in any detail how its transmission system would be operated outside of the Midwest ISO. LGE does not have capabilities for managing transmission operations that are equivalent to those of the Midwest ISO. It has indicated that it could contract with a third party for reliability coordination services, but, it has not selected an alternative provider of those services, described specifically what services such a third party reliability coordinator has the capacity to or would provide, or provided anything other than its own opinions about what such third party services might cost.

LGE has sought to convince the Commission that it can operate and site new generating facilities as if its system was an island, cut off from the regional transmission system and power flows. LGE presented extensive testimony based on models that included no representation of the transmission within LGE or within any other control area.

The record in this case clearly demonstrates that how the transmission system is operated matters with regard to whether:

- There is a proactive capability to minimize reliability risks;
- Transmission assets are fully and efficiently utilized;
- The congestion resulting from regional power flows can be cost-effectively managed;
- LGE has low cost access to integrated energy markets extending from the East Coast to the Rocky Mountains; and
- There will be incentives and transparent price signals that can create large long-term savings for consumers.

VI. No Other Organization Is Suitable for LGE.

In addition to examining the net benefits of Midwest ISO participation, the Commission also sought information as to whether membership in another transmission organization may be more appropriate. The record conclusively answers this question in the negative.

In his Supplemental Testimony, Dr. Morey concludes that "the likelihood of finding an alternative RTO that will be preferred to MISO . . . is very small under any plausible scenario."[147] Dr. Morey concludes that PJM offers the same array of market and reliability services as the Midwest ISO, but at a higher cost.[148] Accordingly, he discounts PJM as an alternative to the Midwest ISO.[149] In this respect, the Midwest ISO notes that even though PJM is a more costly organization, the bundle of services it offers and the functions it performs, which are nearly identical to those provided by the Midwest ISO, confer benefits to Kentucky consumers that exceed the cost of membership. Indeed, on May 19, 2004, the Commission granted American Electric Power ("AEP") conditional authority to transfer functional control of its transmission assets to PJM, stating that such a transfer was consistent with the public interest insofar as stipulation made between the parties, in conjunction with AEP's cost/benefit analysis, demonstrated that the benefits of participation exceeded the costs.[150] Some of the benefits noted by the Commission included greater off-system sales profits; net revenues from the sale of FTRs to transmit power on the AEP-East transmission system; avoided contract costs for services that would be performed by PJM, as well as AEP's option to self-schedule resources to meet native load.[151] These are the same benefits that the Midwest ISO brings to LGE, only at a lower cost.

Dr. Morey's opinion with respect to SPP membership was varied depending on assumptions. At one point, Dr. Morey testifies that "MISO RTO membership is marginally

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147 *See* MJM 9/29/04 Supp. Test. at 10:19-20.

148 *Id.* at 19:21-22.

149 *Id.* at 19:22–20:1.

150 *Application of Kentucky Power d/b/a American Electric Power for Approval to Transfer Functional Control of Transmission Facilities Located in Kentucky to PJM Interconnection,* Case No. 2002-00475, Order (May 19, 2004).

151 *Id.*

preferable to the SPP RTO membership. . . ."[152] At other points, however, he ventures the opinion that, under the most optimistic assumptions about transfer capacity, SPP membership would offer modest advantages.[153] Even this "best case" scenario was subject to a critical caveat: it was assumed that SPP would remain strictly a Day 1 organization and not offer any Day 2 function. Otherwise, SPP's costs of operations would increase to such an extent as to overwhelm any savings ultimately achievable under the best-case scenario. On June 15, 2005, SPP announced that it will establish an imbalance market, which necessarily requires the development of a real-time energy market.[154] The irreducible expenses of the software, telecommunications and computing power necessary to run a 5-minute interval real-time imbalance market render SPP an uneconomic alternative to the Midwest ISO.

CONCLUSION

WHEREFORE, the Midwest ISO respectfully requests that the Commission close this investigation without ordering any change in the continued membership of LGE in the Midwest ISO.

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152 MJM 9/29/04 Supp. Test. at 21:5-6.

153 *Id.* at 21:16-20. Given SPP's reliance on TLRs to address congestion and its inability to control loopflow the high transfer scenario is highly unlikely. More likely, LGE would be returned to the Day 1 environment in which 15,000 MW were interdicted in a three-month period, which would substantially diminish off-system sales. *See generally* 1 T.E. 189:12-15, 190:4-19.

154 *Southwest Power Pool, Inc.*, Submission of Tariff Revisions to Incorporate Energy Imbalance Market and Market Monitoring Plan, Docket No. ER05-1118-000 (June 15, 2005).

Respectfully submitted,

By: ______________________

Stephen G. Kozey
James C. Holsclaw
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC
701 City Center Drive
Carmel, IN 46032
Telephone: (317) 249-5850
Facsimile: (317) 697-0792

Stephen L. Teichler
Sarah E. Rogers
DUANE MORRIS, LLP
1667 K Street, N.W., Suite 700
Washington, DC 20006-1608
Telephone: (202) 776-7830
Facsimile: (202) 776-7801

Katherine K. Yunker
Benjamin D. Allen
YUNKER & ASSOCIATES
P.O. Box 21784
Lexington, KY 40522
Telephone: (859) 255-0629
Facsimile: (859) 255-0746

Attorneys for the
MIDWEST INDEPENDENT TRANSMISSION SYSTEM OPERATOR, INC.

September 6, 2005

CERTIFICATE OF FILING AND SERVICE

I hereby certify that on this the 6th day of September, 2005, the original and ten (10) copies of this Initial Post-Hearing Brief were hand-delivered for filing with the Commission, and a copy was sent by U.P.S. for overnight deliver to:

Elizabeth Cocanougher
Senior Corporate Attorney
LG&E ENERGY CORP.
220 West Main Street
P.O. Box 32010
Louisville, KY 40232

David C. Boehm
BOEHM, KURTZ & LOWRY
Suite 2110 CBLD Building
36 East Seventh Street
Cincinnati, OH 45202

Kendrick R. Riggs
W. Duncan Crosby III
OGDEN, NEWELL & WELCH, PLLC
1700 PNC Plaza
500 West Jefferson Street
Louisville, KY 40202

Elizabeth E. Blackford
Assistant Attorney General
UTILITY & RATE INTERVENTION DIVISION
1024 Capital Center Drive; Suite 200
Frankfort, KY 40601-8204

Attorneys for Midwest Independent Transmission System Operator, Inc.

<u>ATTACHMENTS</u>
to
Initial Post-Hearing Brief of the
Midwest Independent Transmission System Operator, Inc.

A Market-Clearing Hypothetical

B 7/05 Hearing LG&E/KU Cross Exhibit 4

C Comparison of LGEE transactions curtailed via TLR: April thru June 2004 vs. April thru June 2005, 7/05 Hearing Midwest ISO Redirect Exhibit1.

<u>Attachment A</u>

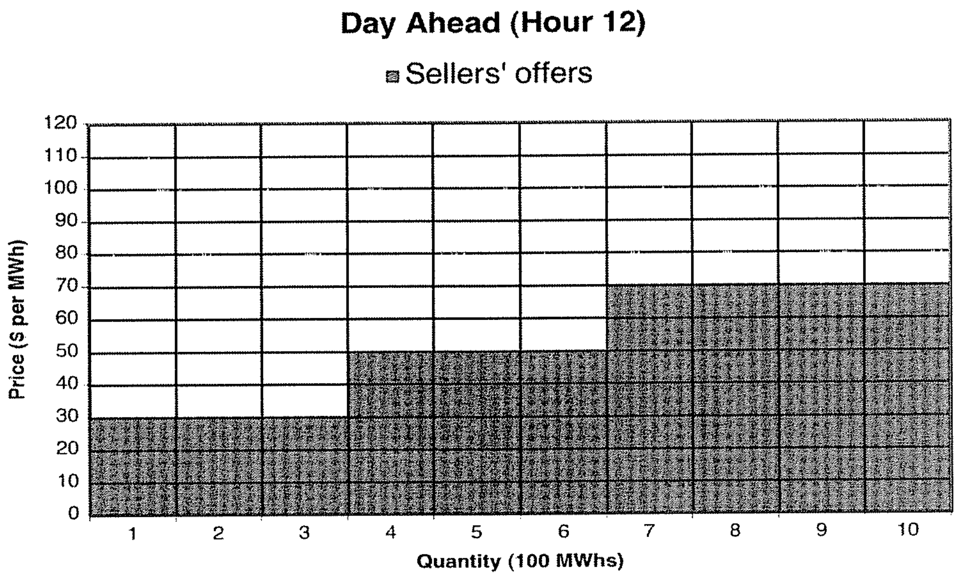
Market-Clearing Hypothetical

During the July 2005 hearing, David C. Boehm, counsel for the Kentucky Industrial Utility Consumers, posed a hypothetical regarding energy offers in the Day-Ahead market.* In his hypothetical, there are three suppliers offering energy. The first offers its generation at $30 per MWh; the second, at $50 per MWh; and the third, at $70 per MWh. The amount of energy they offer is sufficient to supply whatever load might be bid into the Day-Ahead market.

Assume that Mr. Boehm's hypothetical describes the offers for Hour 12 in the Day-Ahead market.

- Seller 1 offers 300 MWh @ $30
- Seller 2 offers 300 MWh @ $50
- Seller 3 offers 400 MWh @ $70

These offers, totaling 1000 MWh, are arranged from lowest offer to highest, to form a supply curve.†



In his hypothetical, the market-clearing price was $70 per MWh.‡ To show that the price clears the Day-Ahead market for Hour 12, we must add demand bids to the hypothetical. Assume, then, that market participants with load to serve submit the following bids:

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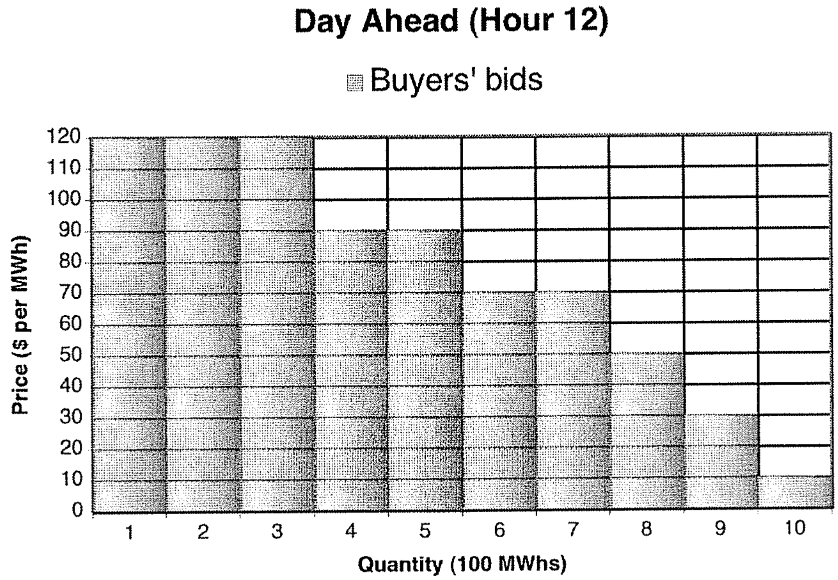
* *See* 1 T.E. 178:11-25.

† *See* Initial Brief, at p.9. As noted by Mr. Harszy, offers being submitted in the actual Day Ahead market are in more graduated steps. 1 T.E. 182:13-16.

‡ 1 T.E. 178:24–179:2.

	MWh	$/MWh		MWh	$/MWh
• Buyer 1	200	70	• Buyer 4	300	120
• Buyer 2	100	50	• Buyer 5	100	10
• Buyer 3	200	90	• Buyer 6	100	30

These offers, totaling 1000 MWh, are arranged from highest offer to lowest, to form a demand curve.

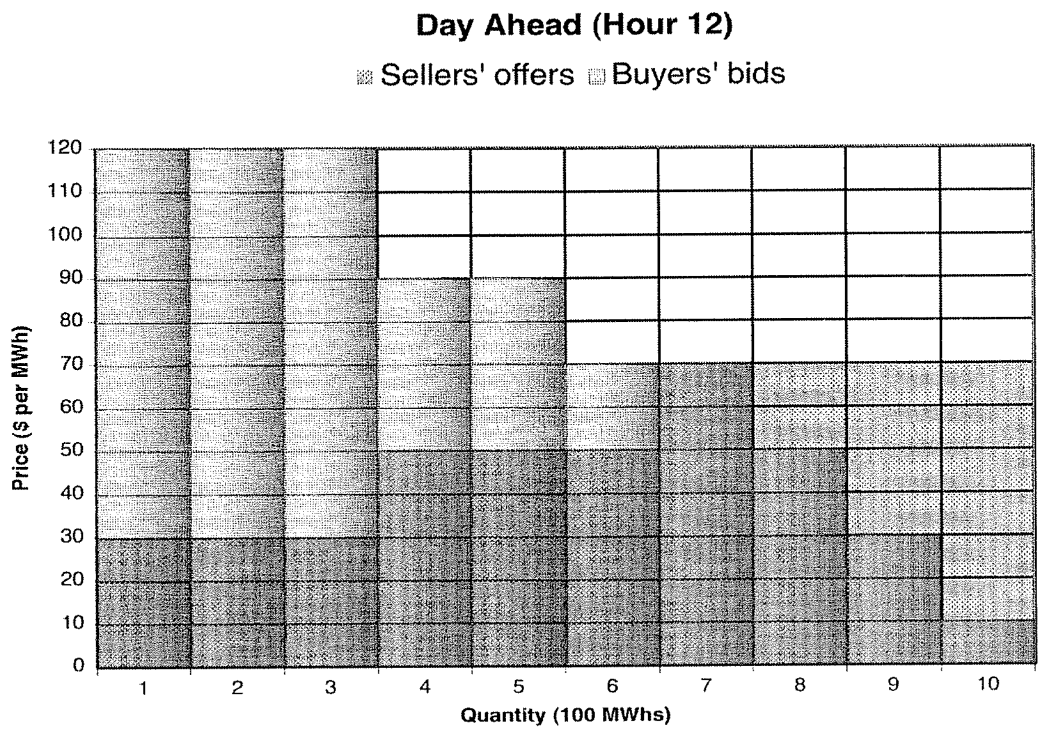


Overlaying the supply curve on the demand curve shows that, before considering congestion and marginal losses, the Day-Ahead Market for Hour 12 will clear 700 MWh at $70.*

Buyers 1, 3, and 4 each will have the loads they bid supplied at $70 per MWh. Buyers 3 and 4 would have been willing to pay more for the power, but it is the lowest cleared bid price that becomes the market-clearing price for Hour 12 power.

Seller 1 and Seller 2 are each to supply 300 MWhs, and Seller 3 is to supply 100 MWh — all at $70 per MWh. Seller 3 would have been willing to supply 300 MWh more at that price, but there is no further demand for Day-Ahead Hour 12 power at that price.

* *See* Initial Brief, at p.9.



The difference between what the buyers were willing to pay and the market-clearing price is the "consumer surplus"; the difference between what the sellers were willing to accept and the market-clearing price is the "producer surplus." In this hypothetical, consumer surplus totals $19,000; producer surplus, $18,000.

	Buyers			**Sellers**	
	willing to pay	*pay*		*willing to accept*	*accept*
1.	$ 14,000	$ 14,000	1.	$ 9,000	$21,000
3.	18,000	$ 14,000	2.	15,000	21,000
4.	36,000	21,000	3.	7,000	7,000
Total	$ 68,000	$ 49,000		$ 31,000	$ 49,000
DIFFERENCE	**$19,000**			**$ 18,000**	

Report in $k	APRIL	MAY	JUNE	TOTAL
Energy Transactions	($6,793)	($14,332)	($17,095)	($38,219)
DA Energy, Cong & Loss	(3,872)	(3,100)	8,382	1,409
RT Energy, Cong & Loss	650	(4,343)	(7,036)	(10,729)
Refund of Overcollected Losses	(1,729)	(1,880)	(3,545)	(7,153)
RSG Make Whole Payments	(1,812)	(3,296)	(10,682)	(15,789)
FTR Revenues	(71)	(1,759)	(4,282)	(6,111)
Uninstructed Deviation Penalties	41	45	68	154
Miscellaneous	($74)	($158)	($265)	($497)
Net Inadvertent	(74)	(158)	(265)	(497)
Miscellaneous	0	0	0	0
Market Admin Fees	$551	$612	$558	$1,722
DA	410	444	485	1,339
RT	43	56	58	157
FTR	99	112	15	226
RSG Distribution Amount	$869	$1,094	$2,782	$4,745
DA	142	170	260	572
RT	727	924	2,523	4,173
Revenue Neutrality Uplift	$1,575	$1,797	$3,738	$7,110
UD Credit	(96)	(56)	(158)	(310)
JOA Uplift	0	16	1	17
RSG 2nd pass	227	64	168	458
CarveOut GFAs	1	0	3	4
OptionB GFAs	0	0	1	1
Inadequacy Uplift	1,444	1,822	3,723	6,989
Total Charges/Revenues	($3,871)	($10,988)	($10,281)	($25,140)

LGEE Transactions Curtailed via TLR - April thru June 2004:

29 imports = 2,492 MWHs
98 exports = 13,239 MWHs

2004 Total: 127 Transactions = 15,731 MWHs

LGEE Transactions Curtailed via TLR - April thru June 2005:

1 import = 450 MWHs
0 exports

2005 Total: 1 Transaction = 450 MWHs