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PUBLIC SERVICE COMMISSION

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

Additional Supplemental Testimony of Dr. Ronald R. McNamara, filed by Midwest Independent Transmission System Operator, Inc.

Midwest Independent Transmission System Operator, Inc. ("Midwest ISO") hereby files its Additional Supplemental Testimony of Dr. Ronald R. McNamara, with attachments. The Midwest ISO makes this filing pursuant to the orders of the Commission, filed February 4 and 17, 2005. Included with this filing are the following: (a) Additional Supplemental Testimony of Dr. Ronald R. McNamara and its accompanying attachments; and (b) one CD-ROM containing two (2) compressed (.zip) files of workpapers.

Respectfully submitted,

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CERTIFICATE OF FILING AND SERVICE

I hereby certify that on this the 21st day of February, 2005, the original and ten (10) copies of this Additional Supplemental Testimony, including the aforementioned CD-ROMs, were hand-delivered to the Commission for filing, and copies were sent, via U.P.S., to:

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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

Additional Supplemental Testimony of

Dr. Ronald R. McNamara

Vice President of Market Management

Midwest Independent Transmission System Operator, Inc.

Filed: February 21, 2005

Q. **PLEASE STATE YOUR NAME AND BUSINESS ADDRESS.**

A. My name is Ronald R. McNamara. I work at 701 City Center Drive, Carmel, Indiana 46032.

Q. **ARE YOU THE SAME RONALD R. MCNAMARA WHOSE TESTIMONY HAS PREVIOUSLY BEEN FILED IN THIS PROCEEDING?**

A. Yes, I am.

Q. **WHAT IS THE PURPOSE OF THIS ADDITIONAL SUPPLEMENTAL TESTIMONY?**

A. This testimony is presented in accordance with the Commission's Order of February 4, 2005, to provide the Commission a common basis on which to compare the results of the benefit – cost studies prepared by the Midwest ISO and Louisville Gas & Electric Company / Kentucky Utilities ("LG&E / KU" or "the Companies").

The purpose of this testimony is to provide the Commission with the best currently available information on the likely benefits and costs of continued Midwest ISO operation of the LG&E / KU transmission system. To that end, my additional testimony:

- Presents the results of additional PROMOD IV® modeling runs using essentially the same portfolio of LG&E / KU resources – generating stations and power purchase contracts – that were used in the Companies' analysis;

- Recognizes that the Companies have offered a range of load forecasts in various contexts and presents results of further PROMOD IV® modeling runs using both the load forecast used in the Companies PROSYM® model runs and a resource portfolio comparable to that used in the Companies' study;
- Provides results that reflect the final allocation of all spring and summer season Financial Transmission Rights ("FTRs");
- Presents the results of a sensitivity analysis that is based on the Companies' resource portfolio and tests our conclusions under a scenario that is the least favorable to the Companies' remaining in the Midwest ISO; and
- Describes the remaining significant differences between the Companies' study and the analysis presented here, so that the Commission can evaluate the weight that should be given to each set of results.

Q. **WOULD YOU PLEASE SUMMARIZE THE FINDINGS OF YOUR ADDITIONAL ANALYSIS?**

A. This additional analysis does not change my earlier conclusion that leaving Midwest ISO will impose significant costs on LG&E / KU and its customers.

Using a resource portfolio based on the Companies' study, the net cost of the Companies' Transmission Operations – Reliability Coordination ("TORC") option, after considering all of the costs of remaining in the Midwest ISO, is higher than the net cost of the TORC option in our earlier studies. When compared to the results in my Corrected and Updated Rebuttal Testimony, this result reflects:

- Lower congestion costs as a result of excluding generators with below average Locational Marginal Prices ("LMPs") from the Companies' resource portfolio and narrowing the differential between the LMPs at generation and load buses;
- Increased cost savings from regional security constrained economic dispatch of the Companies' resource portfolio;
- Increased generation and greater off-system sales from the remaining LG&E / KU generating units as a result of excluding more than 2,300 MW of additional generating capacity from the Midwest ISO market; and
- A reduction in transmission revenue for the TORC option.

The Companies' attempt in their rebuttal testimony to back into revenues and costs associated with their resource portfolio (*See* Supplemental Rebuttal Testimony of Mathew J. Morey at p. 18-25 and Rebuttal Testimony of David S. Sinclair at p. 12-15) was obviously inappropriate because it failed to take into consideration the impacts on dispatch and prices of excluding resources from Midwest ISO dispatch and energy markets. Changing the LG&E / KU resource portfolio and the resources that will be included in the Midwest ISO footprint has operational impacts (i.e. physical impacts). These impacts cannot be captured by accounting calculation that shifts revenues and costs from one bucket to another.

The results that we are presenting here reflect how the system would operate with the LG&E / KU resource portfolio used in the Companies' study.

Using a smaller resource portfolio based on the Companies' study, the TORC option would impose near-term recurring costs on LG&E / KU of $56.9 million per year. This figure does not include the exit fee that the Companies would pay to withdraw from the Midwest ISO. The exit fee continues to be $40.2 million. Thus, for the period 2005 – 2010, the net present value cost of the TORC option to LG&E / KU, after taking into account all of the costs of Midwest ISO membership, would be $330.6 million.

When we modeled the combination of the Companies' resource portfolio and the lower demand and energy forecast used in the Companies' modeling of the LG&E / KU system, the net recurring cost of the TORC option is $58.0 million per year. This figure also does not include the exit fee of $40.2 million. In this scenario, the net present value cost of the TORC option for the period 2005 – 2010, after taking into account all of the costs of Midwest ISO membership, is $335.9 million. The results for this scenario reflect the costs of serving lower forecasted native loads and additional opportunities for LG&E / KU to make off-system sales.

Our results and our approach stand in sharp contrast to the modeling presented by LG&E / KU. To accept the Companies' investigation as indicative of the benefits of Midwest ISO economic dispatch and congestion management would be to judge a book by its title. In a proceeding to address the value of regional versus local operation of the transmission system, the Companies models are exactly like books in which almost every page is empty. There is no representation of the transmission system or the transmission constraints within LG&E / KU or within any other utility in the Companies' PROSYM model. And, there is no representation of the transmission system or transmission constraints internal to any of the large Regional Transaction Groups in the Companies' MIDAS model. Transmission is represented in these models as only a set of simplistic, static, path limits at the boundaries between large, often multi-state regional areas. The models, in effect, assume that transmission is free and unlimited inside each of these regional areas. Nothing could be further from the truth. If the Companies' studies have not found benefits from regional transmission management, it is because they have relied on models that are not designed to address the question at hand – whether or not regional coordination of the transmission system is beneficial to Kentucky.

For example, Company witness Sinclair complains that the PROMOD® model used in our studies is not sufficiently detailed because we did not take into account differences in the hourly load shapes at individual buses in the transmission system. Rebuttal Testimony of David S. Sinclair at p. 7. However, in their own models, the Companies use a single load per hour for LG&E / KU and for each other market area. In the Companies' models, loads are not distributed at individual buses in the transmission system. LG&E / KU Response to Midwest ISO Data Request Dated January 25, 2005, Question 26. Indeed, the Companies could not distribute loads to transmission buses because their models do not contain any representation of the transmission system internal to LG&E / KU or within any Regional Transaction Group.

The Midwest ISO runs more complex models that reflect actual bus level loads and generation throughout its footprint. They are among the tools we are using to implement regional security constrained economic dispatch and efficiently manage transmission congestion.

Q. **WHAT ARE THE IMPLICATIONS OF THE MIDWEST ISO'S IMPLEMENTATION OF REGIONAL SECURITY CONSTRAINED ECONOMIC DISPATCH FOR THE STUDIES PRESENTED IN THIS PROCEEDING?**

To place the analysis that has been presented in this proceeding in context, starting on April 1, 2005, with implementation of the Midwest ISO's Open Access Transmission and Energy Markets Tariff ("TEMT"), actual data will become collected on the cost impacts of regional economic dispatch, the Companies' actual operating behavior, and how those results compare to historical performance. LG&E / KU are required by contract to remain in the Midwest ISO at least through the end of 2005. As such, the Midwest ISO is prepared to assist the Commission in evaluating the impacts of the TEMT on Kentucky consumers as actual data becomes available.

Q. HOW CONFIDENT CAN THE COMMISSION BE THAT THE COMPANIES' TORC OPTION WOULD IMPOSE SIGNIFICANT NET COSTS ON LG&E /KU AND ITS CUSTOMERS?

A. The Commission can have a high degree of confidence that leaving the Midwest ISO would be significantly more expensive for Kentucky consumers than remaining in the Midwest ISO.

The largest variance in our prior results related to what FTRs would be allocated LG&E / KU. On January 31, 2005, the Midwest ISO filed with the Federal Energy Regulatory Commission the results of its allocation of all spring and summer FTRs, which were based on market participant nominations. We have used the Companies' actual FTR allocations in this analysis. Completion of the full FTR allocations has significantly narrowed the range of plausible outcomes.

Moreover, using a resource portfolio based on the Companies' study, we have modeled a scenario that our earlier studies suggested would be least favorable to continued Midwest ISO membership. This scenario combined low fuel prices with lower than anticipated flowgate utilization after market implementation. With these less favorable inputs, excluding any benefit from the distribution of Midwest ISO transmission revenues, and using a lower end value for FTRs, the annual non-recurring cost of the TORC option remains at least $20.4 million per year. This number does not include the exit fee of $40.2 million.[1]

[1] Given the limited time available to complete this additional analysis and the availability of actual FTR allocations, we reduced the number and range of sensitivity cases analyzed, focusing on cases that our prior analysis indicated would be least likely to support continued LG&E / KU participation in the Midwest ISO.

These results confirm my conclusion that there are no plausible scenarios in which it is likely that LG&E / KU could reduce their costs by withdrawing from the Midwest ISO.

Q. **WHAT ARE THE IMPLICATIONS FOR THIS ADDITIONAL ANALYSIS OF THE MIDWEST ISO HAVING COMPLETED THE ALLOCATION OF FINANCIAL TRANSMISSION RIGHTS?**

A. The Midwest ISO completed the allocation of summer and spring 2005 Financial Transmission Rights.[2] I have reflected these actual allocations in my analysis. At the time that I filed my earlier testimony and the updates to that testimony, FTR allocations had not yet been completed and remained the largest single source of variance in our forecast of the benefits and costs of MISO membership. Completion of the allocation process for the summer and spring seasons significantly narrows the range of plausible outcomes.

Summer is the season with the greatest limitations on feasible FTR allocations. To annualize FTR values, I have applied the actual spring and summer FTR allocations for fall and winter season FTRs. As I explained in earlier testimony, the application of spring and summer actual allocations to the fall and winter seasons is a conservative approach because the transmission system in this area is

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Given that the scenarios analyzed were limited in this manner, it is possible that the costs to LG&E / KU of withdrawing from the Midwest ISO could exceed those quantified in this analysis.

[2] Consistent with the allocation of FTRs, we also have updated our estimate of the uplift for addressing unhedged congestion in Narrow Constrained Areas.

less heavily loaded and equipment ratings are often higher in the winter than in the summer. Thus, feasible winter allocations will tend to be higher than those for the summer season. Moreover, the Companies may well pursue nominations that are more profitable for the fall and winter seasons than what I have used. To illustrate a plausible range of outcomes, the accompanying tables include high and low forecasts that are 110% and 90% of my conservative forecast of the value of LG&E / KU FTRs.

Q. WHAT DO THE MODEL RUNS THAT YOU ARE PRESENTING IN THIS TESTIMONY INDICATE ABOUT PATTERNS OF CONGESTION, TRANSMISSION CONSTRAINTS, AND PRICES WITHIN LG&E / KU?

A. The Louisville area, one of the major LG&E / KU load centers, is located upstream from constraints on the LG&E / KU transmission system. As a result, using the Companies' resource portfolio, internal congestion costs are negative during more than 1,800 hours in the year.[3] Negative congestion costs occur when broader regional power flows create transmission constraints within LG&E / KU and much of the Companies' load is upstream from these constraints. During these hours, the average price of power at LG&E / KU load buses falls below the price at the Companies' generating stations downstream from the constraints. Results for two of these hours are illustrated in Supplemental Appendix B.

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[3] In earlier studies, we observed several hundred hours in which LG&E / KU congestion costs were negative. Negative congestion costs were observed in fewer hours in earlier studies because those studies treated additional low priced generation as being in the LG&E / KU control area.

The pattern of constraints within LG&E / KU has the additional effect that generating capacity at locations upstream of commonly occurring constraints is less valuable and will be economically dispatched less frequently than generation at downstream locations. Our analysis shows that the six combustion turbines at Trimble County are economic to dispatch only 22 to 44 hours during the year. Similar combustion turbines at the E. W. Brown station downstream of the constraint are economic to dispatch up to 236 hours per year. Moreover, the average LMP at Brown of $30.33 per MWh was 30% higher than the average LMP of $23.35 per MWh at Trimble County. We performed a direct comparison based on 2005 forecasted LMPs of the value of a representative Trimble County combustion turbine to the value of placing an identical combustion turbine at the Brown station. Our analyses suggests the unit placed at Brown would be economic to operate 180 hours per year have a value to consumers of $2,376,446 for 2005, while at Trimble County the same unit would be economic to dispatch only 22 hours and have a value of only $274,167 per year. Locating an additional combustion turbine at Trimble County instead of downstream of the transmission constraints within LG&E / KU could be costing consumers as much as $2.1 million per year in increased production and purchased power costs. One of the benefits of LG&E / KU participation in the Midwest ISO is that it will make transparent the economic impacts of regional power flows on unit siting decisions.

Q. **WHAT MODIFICATIONS HAVE YOU MADE TO YOUR BASE CASE MODELING TO REFLECT A PORTFOLIO OF LG&E / KU RESOURCES THAT IS COMPARABLE TO THOSE USED IN THE COMPANIES' STUDY?**

A. Consistent with the Companies' Supplemental Rebuttal Testimony, we have made the following changes to LG&E / KU resources for purposes of this additional analysis:

- The Coleman, Green, Henderson II, Reid, and Wilson generating units operated by LG&E / KU affiliate Western Kentucky Energy have been modeled as being in the Big Rivers Electric Cooperative ("BREC") control area and excluded from the calculation of benefits and costs to LG&E / KU.
- We have reflected the retirement of Green River Units 1 and 2 and excluded them from the analysis.
- We have added 98 MW of capacity at the E.W. Brown station combustion turbines during the months April through September to reflect the installation of inlet air cooling.
- We have treated the LG&E / KU power purchase agreements with OVEC and EEI as fixed price agreements and included them in the LG&E / KU resource portfolio.
- We have excluded the Dynegy units from the LG&E / KU resource portfolio.

Q. **COMPANY WITNESS MOREY ALSO IDENTIFIES THE INCLUSION OF THE PARIS DIESEL GENERATOR IN YOUR ANALYSIS AS AN "ERROR". (SUPPLEMENTAL REBUTTAL TESTIMONY OF MATHEW J. MOREY AT PAGE 9-11.) HOW HAVE YOU TREATED THIS UNIT IN YOUR ADDITIONAL SUPPLEMENTAL ANALYSIS?**

We have continued to represent the Paris Diesel unit as being in the LG&E / KU control area because the unit is inconsequential and it would be an error to remove it. First, the Paris unit has no material impact on the benefits and costs of LG&E / KU Midwest ISO membership. The unit is seldom economic to operate. The Paris unit operated for 9 hours, generating 49 MWh per year, when LG&E / KU was modeled as being in the Midwest ISO and operated for 3 hours, generating 17 MWh, under the Companies' TORC option. The total annual cost of operating the Paris generator equals $ 5,169 for the case in which LG&E / KU remains in the Midwest ISO and $ 1,722 under the TORC option. Second, the unit is physically located in the LG&E / KU control area. Third, given that the unit runs when LG&E / KU interrupts its power sales to the City of Paris, the operation of this unit is the result of decisions made by LG&E / KU. Finally, if LG&E / KU are not responsible for the cost of operating the Paris diesel generator, City of Paris would be responsible for the cost of operating this unit.

Q. **HOW DO THE FORECASTED LG&E / KU LOADS USED IN THE COMPANIES' STUDY IN THIS PROCEEDING DIFFER FROM THOSE REPORTED FOR THE COMPANY IN OTHER CONTEXTS?**

A. The forecasted peak loads used in the Companies' modeling of the LG&E / KU system in this proceeding are lower than what has been reported for the Company for other purposes.

In his Supplemental Testimony filed in September 2004, Company witness Gallus indicates that, "The native load forecast utilized in this study was developed in February 2004 and is LGE/KU's most recent forecast." This statement is followed by a Table entitled "February 2004 Combined LGE/KU Load Forecast." The table includes a Peak MW value for 2005 of 6,629 MW. Supplemental Testimony of Martyn Gallus at Appendix B, Page 8. This discussion appears in a section of the Appendix that addresses LG&E / KU production cost modeling using the PROSYM® model.

Mr. Gallus's figure is a lower than the 6,692 MW summer peak reported in the "Joint Company Energy and Peak Demand Forecast" filed with the Direct Testimony of David S. Sinclair, *In the Matter of the: Joint Application of Louisville Gas and Electric Company and Kentucky Utilities Company for a Certificate of Public Convenience and Necessity and a Site Compatibility Certificate, for the Expansion of the Trimble County Generating Station,* Case No: 2004-00507, on December 9, 2004.

Both of these forecasts are significantly lower than:

- The 7,309 MW 2005 summer peak load for the LG&E / KU planning area that the Companies reported to the Federal Energy Regulatory Commission in Form 714 on May 28, 2004, See: Appendix E, Form 714 at Part III, Schedule 2, certified on behalf of the Companies by Mark S. Johnson; and
- The 7,451 MW peak load for the LG&E / KU control area reported in the North American Electric Reliability Council ("NERC") Summer Peak Power Flow Case for 2005, released in November 2004. The NERC power flow case generally reflects data maintained by and preliminary cases made available for review by member entities such as LG&E / KU. NERC Planning Standards require the forecasted demand data maintained by individual systems and submitted to NERC be consistent with data used for system modeling and reliability planning and with the data reported to government agencies. NERC Planning Standards II (D).

The 828 MW difference between the 2005 peak load forecast used in the Companies' PROSYM® model and in the NERC power flow case and the 680 MW difference between the February 2004 forecast used in PROSYM® and the planning area peak subsequently certified to the Federal Energy Regulatory Commission are larger than what might be reasonably expected.

The load figures that Mr. Gallus's testimony indicates he used for LG&E / KU's PROSYM® modeling are also lower than what appear to be loads the

Company used for the "LGEE" Regional Transaction Group in the MIDAS model. What appears to be a MIDAS input file was provided as part of the Companies' MIDAS workpapers, "MarketAreaLoadData.xls". LG&E / KU Response to Midwest ISO Data Request No. 1, dated October 6, 2004, filed October 20, 2004. This workpaper suggests that MIDAS model may have used a 2005 summer peak load of nearly 8,110 MW for LGEE Regional Transaction Group. This includes more than 1,600 MW of forecasted Ohio Valley Electric Cooperative ("OVEC") load. As I will address later, these OVEC load figures are greatly inflated.[4]

The forecasted energy and demand values used in the Midwest ISO's base case model runs were developed by scaling individual utility FERC Form 714 forecasts to NERC Energy Supply and Demand ("ES&D") forecast for the region in which the utility system is located. This scaling is performed to ensure the use of a consistent set of forecasts across the study area. Our forecasted loads represent energy requirements at the generation level and include transmission and distribution losses. Our 2005 summer peak forecast for the LG&E / KU control area is 7,248 MW. It is higher than the peak load forecast used by the Companies in this proceeding, but lower than that submitted by the Companies on FERC Form 714. Our base case energy forecast for LG&E / KU is 6% higher than the 2005 energy sales figures used

[4] As indicated at a later point in my testimony, the MIDAS workpapers provided by the Companies include two files that contain inconsistent load forecasts.

in the Companies' study. This is a result of the NERC ES&D energy forecast for the region exceeding the sum of member company energy forecasts.

Given the differences in forecasted loads between the two studies and within the Company's own peak load forecasts, we performed additional model runs using both the same energy and demand levels that Mr. Gallus reports having used in his PROSYM® modeling and the resource portfolio that I described above which tracks that used by the Companies. The net recurring cost of the TORC option, after deducting all of the costs of Midwest ISO membership, is approximately $1 million per higher using the Companies' lower forecasted loads than using the Midwest ISO's load forecast.

Q. **WHAT MAJOR DIFFERENCES REMAIN BETWEEN THE ANALYSIS THAT YOU ARE FILING TODAY AND THE COMPANIES' MODELING?**

A. The most significant difference is that the PROMOD IV® model used in my testimony is the only model in this proceeding that provides any representation of transmission constraints and transmission capabilities within a Regional Transaction Group or inside a Market Area. The Midwest ISO is implementing the TEMT to manage transmission congestion in an efficient and non-discriminatory manner. The PROMOD IV® model is the only model in this case with the capability to quantify of the benefits of efficiently managing transmission congestion through regional security constrained economic dispatch.

The transmission system is represented in the Companies' MIDAS Gold model by static flow limits at highly simplified interfaces between each of the model's 26 Regional Transaction Groups and the near by Regional Transaction Groups. These 26 regional groups provide a simplified representation of approximately 140 control areas in North America. MIDAS Gold does not include any representation of the transmission system or transmission constraints within any of its Regional Transaction Groups.

Similarly, in the Companies' PROSYM model, the representation of the transmission system is limited to static flow limits on simplified interfaces between LG&E / KU and the adjacent TVA, PJM, and MISO systems. There is no representation of the transmission system or transmission constraints within either LG&E / KU or any of the other three systems. Although the Companies have used PROSYM to "model the details of its own system" (Supplemental Rebuttal Testimony of David S. Sinclair at 5), it includes no representation of transmission constraints internal to LG&E / KU.

To the extent these static, simplified transfer limits have been set conservatively, they would, as Company witness Gallus indicates, understate the amount of transfer capability available during a majority of hours during the year. Supplemental Testimony of Martyn Gallus at Appendix B, page 8. Thus the Companies' models are both incapable of analyzing congestion management and unable to identify additional opportunities for the Companies to make off-system sales as a result of the Midwest ISO's ability to facilitate greater utilization of the transmission system.

In both the Companies' MIDAS and PROSYM models, loads are not distributed by location or within multi-company Transaction Groups by company. They are represented as a single hourly number for each regional group. As a result, there is no guarantee that the generators dispatched by MIDAS or PROSYM could actually serve the loads being represented in any given hour.

MIDAS generates hourly prices for each Regional Transaction Group. Because these are not nodal prices, they cannot be used to identify congestion costs or determine the value of FTRs. Indeed, without a better representation of transmission constraints, there is no way to determine whether LG&E / KU actually could sell or buy power at the prices forecasted by MIDAS. The PROSYM® model does not generate prices, but represents them as fixed hourly inputs taken from MIDAS.

The manner in which the Companies have used their models assumes away any possibility of transmission constraints within LG&E / KU and within any of the 26 MIDAS Regional Transaction Groups. The MIDAS Gold and PROSYM models, as used by LG&E / KU, are simply incapable of providing any indication of the benefits of regional security constrained economic dispatch and congestion management.

Q. **ARE THERE ANY OTHER DIFFERENCES BETWEEN YOUR ADDITIONAL SUPPLEMENTAL ANALYSIS AND THE COMPANIES' STUDIES?**

A. Yes. The Midwest ISO's study forecasts electricity prices that are based on the marginal cost of producing and transmitting power. This is how efficient power markets work. The Companies' price forecasts differ in two potentially significant ways.

First, the MIDAS model introduces a "scarcity function" into the Companies' price forecasts. The "scarcity function" is a price adder that raises forecasted prices as load increases relative to regional generating capacity. The use of such an adder, when the market is not close to shortage, permits the analyst to back into a predetermined result. In this case, it appears that Companies started to apply a scarcity price adder when load reached 75% of available generating capacity. At 80% of capacity, the Companies' analysis uniformly increases prices by $10 per MWh. At 85% of capacity, prices are uniformly raised by $30 per MWh. Such arbitrary adders do not reflect the marginal cost or value of generation. This is particularly true for the MISO and PJM markets in which operating reserves are shared across regions that encompass multiple transaction groups.

Second, the Companies appear to have used load data that contains dated and incorrect load information. Specific differences that we identified include:

- The Companies' workpapers contain two different sets of demand and energy figures for OVEC. The workbook entitled "MarketAreaLoadData.xls" includes a forecasted 2005 OVEC peak load of 1,658 MW and annual energy use of 11,220 GWh. This file appears to be in a MIDAS data format and may have been used in the Companies' MIDAS analysis. In a second LG&E / KU workbook entitled "MIDAS – Load Forecasts – Platts Basecase.xls," the 2005 OVEC summer peak is 100 MW with annual energy use of 531 GWh. This data is in a format provided by Platts, a commercial aggregator of energy data. The higher forecast, that appears to be in a MIDAS data format, reflects OVEC loads prior to the closure of the United States Enrichment Corporation's ("USEC") Portsmouth Gaseous Diffusion Plant. The USEC facility ceased enrichment in May 2001 and halted a reduced level of operations for inventory clean up in 2003. The "MarketAreaLoadData" worksheet indicates that OVEC loads were included in Regional Transaction Group #4, the LGEE Regional Transaction Group.[5] LG&E / KU Response to Midwest ISO Data Request No. 1, dated October 6, 2004, filed October 20, 2004.
- The load data used in the Companies' MIDAS analysis includes errors in the manner in which company loads are split between regional transaction

[5] Additionally, the 2005 annual energy use for the EEI market area in the "MarketAreaLoadData" worksheet is 84% higher than the comparable annual energy in the Platts worksheet.

groups. For example, the Companies' forecast places 71% of Entergy loads in the Entergy North market area. The Entergy system is divided by transmission constraints that limit power transfers at the Amite South interface. Only about 44% of Entergy load is located north of this major transmission constraint. The Companies' analysis has shifted the location of approximately 6,000 MW of load from southern Louisiana to a transaction group that is directly connected to the TVA market where LG&E / KU makes off-system sales. Similarly, the Companies place 57% of GPU load in GPU West – west of the major transmission constraints within PJM. The area west of these constraints actually contains less than 48% of GPU load. The Companies have shifted approximately 500 MW of load into a transaction group closer to the LG&E / KU system. Additionally, the Companies' split of the Ameren system places 80% of Ameren Union Electric ("UE") and Central Illinois Public Service ("CIPS") loads in Ameren's UE service territory. In reality, Union Electric accounts for only 68% of the combined UE and CIPS load. This results in an additional shift of more than 1,300 MW.

- There are 470 MW of load served directly by the Coleman plant and 447.8 MW of load tied to the Reid plant that are not included in the Companies' BREC load forecast (679.8 MW in 2005). (LG&E / KU Response to Midwest ISO Data Request No. 1, dated October 6, 2004, filed October 20, 2004; workbook MarketAreaLoadData.xls.) While the Companies' MIDAS modeling understates the load in its BREC Regional Transaction

Group, prices for the BREC transaction group were not carried forward into the PROSYM® model that was used to generate the results the Companies have presented in this case.

Given that MIDAS is based on matching generation to loads in regional transmission groups, errors of this magnitude will affect the results. Overstating loads in the MIDAS transaction groups that either were used or are closer to those used to generate prices for the Companies' PROSYM® modeling may have increased the forecasted prices for off-system sales in the Companies' analysis.

Company witness Sinclair argues that the Companies' price forecasts are reasonable because, given the way the Companies set up their model, it produced prices that are similar to forward bilateral trading prices at the Cinergy Hub. This superficial similarity does not make the Companies' price forecasts correct, let alone representative of what spot prices will be in Midwest ISO energy markets. Mr. Sinclair's frame of reference is to on-peak forward contract prices – prices for energy to be delivered in the future. These are prices in bilateral contracts that reflect limitations on efficient price discovery in bilateral markets, a forward market risk premium on energy to be delivered in the future, and a risk premium associated with the comparatively limited liquidity of the Cinergy market. The Midwest ISO TEMT introduces an entirely new frame of reference – highly liquid day ahead and real time markets based on security constrained unit commitment and economic dispatch. It is inappropriate to expect forward bilateral contract prices for on-peak delivery into the Cinergy Hub to match the average LMPs forecasted in our analysis.

Our forecast of the 2005 average on-peak LMP for the Cinergy load zone is \$32.34 per MWh. It reflects the comparatively low marginal cost local generation and limited impact of constraints in this portion of the transmission system. It does not include the tariff charges and premiums that are built into the bilateral contracts that historically traded at the Cinergy Hub. Our forecast reflects the marginal cost of delivering energy at specific locations on the grid and is not based on arbitrary inputs or an assumption that a future with efficient regional markets will necessarily approximate a past in which those markets did not exist.

Q. **HAVE YOU MADE OTHER UPDATES TO YOUR EARLIER STUDIES?**

A. Yes. When adjusting the resource portfolio, we placed loads that were tied to specific generating units with those units. The Midwest ISO also identified a small number of unit retirements and transmission upgrades that have recently occurred or will be completed by June 2005. We have reflected these recent changes in the model runs presented in this testimony.[6]

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[6] These changes include the retirement of the Collins units in Commonwealth Edison, and transmission upgrades and flow limit changes for the Cane Run transformer in LG&E / KU (rating increased from 287 to 370MW), Northside – Jeffersonville line in LG&E / KU (rating increased from 258 MW (Summer) / 287 MW (Winter) to 319 MW / 390 MW respectively); Buffington Transformer in Cinergy; the Kansas - Murdock 138 kV line in Ameren; the Cascade Creek flowgates in Northern States Power and MAPP; the Lemoyne - W Fremont flowgate in First Energy and AEP; the Dale - West Canton line in AEP and First Energy; and the Petersburg Transformer in SIGE. Midwest ISO modelers update monitored elements and limits as appropriate updates are identified.

Q. **LEAVING ASIDE THE CHANGES YOU HAVE ALREADY DESCRIBED, ARE THE MODEL RUNS PRESENTED WITH THIS TESTIMONY COMPARABLE TO THOSE DESCRIBED IN THE CORRECTIONS AND UPDATES TO YOUR SUPPLEMENTAL REBUTTAL TESTIMONY?**

A. Yes. Please refer to the Corrections and Updates to my Supplemental Rebuttal Testimony filed with the Commission on January 20, 2005 for a more complete description of our modeling methodology and model inputs.

Q. **WHAT IS THE RELATIONSHIP BETWEEN THIS TESTIMONY AND THE MODELING RESULTS PRESENTED IN YOUR CORRECTED AND UPDATED SUPPLEMENTAL REBUTTAL TESTIMONY?**

A. My current testimony is offered to provide the Commission information on the options as they have been addressed in the Companies' benefit – cost study. We appreciate the opportunity to provide this information to the Commission.

The principal difference between this analysis and that presented in my prior testimony relates to the dispatch of units operated by an LG&E / KU affiliate, Western Kentucky Energy ("WKE"). Although the Midwest ISO could accommodate an arrangement that included these units in our security constrained economic dispatch, requesting such an arrangement is at the discretion of LG&E / KU as a member company.

I have attached Tables to this testimony reflecting the results of the additional modeling described in this testimony and supporting material. For the convenience of the Commission and parties, I also have provided a comparison table (Appendix D) listing findings from this study using a resource portfolio based on the Companies' analysis and, where appropriate, identifying the equivalent results presented in my earlier Testimony.

Q. **DOES THIS CONCLUDE THE YOUR ADDITIONAL TESTIMONY IN RESPONSE TO THE COMMISSION'S ORDER OF FEBRUARY 4, 2005?**

A. Yes.

VERIFICATION

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

Ron R. McNamara

Ronald R. McNamara

STATE OF INDIANA)

COUNTY OF HAMILTON)

Subscribed and sworn to before me by Ronald R. McNamara, on this the 21st day of February 2005.

Dorothy M. Shute

Notary Public

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

(SEAL)

Suppl. Appendix B: Analysis of Locational Pricing Patterns within LG&E

In many hours of our simulation, the market value of LG&E/KU generation is, on the average, greater than the market cost of serving LG&E/KU load. As a result, there are over 1800 hours per year in which total congestion costs within LG&E/KU may be negative. This pattern reflects the impact of regional power flows on the operation of transmission and generation in the LG&E/KU system.

A look at three hours in particular provides insight as to how congestion in the LG&E region causes this "reversal" of congestion costs.

Hour 20 of April 1, 2005, shows the following LMPs in and around LG&E:

Location	LMP ($/MWh)
LG&E Load Zone	32.3
Brown (bus 27009)	40.4
Ghent (bus 27138)	39.3
Green River (bus 27144)	38.8
Mill Creek (bus 27253)	22.7
Paddys Run (bus 27293)	23.5
Trimble (bus 27409)	22.9
Tyrone (bus 27413)	40.2
Petersburg (Indiana)	38.0
Tanners Creek (Ohio)	44.2

In this hour, the constraint affecting LG&E/KU prices is from Northside to Clifty Creek (Kentucky into Indiana). This constraint depresses prices in an area of surplus generation from Trimble County southwest to Mill Creek and Cane Run, affecting much of the load in the Louisville area. Large generators to the east and north, such as Ghent and Brown are downstream of this constraint, and have significantly higher LMPs. See Figures 1 and 2.

Hour 13 on July 2, 2005, shows similar behavior of LMPs, but due to a set of different constraints and a flow of power across the region from coal units north and west of LG&E/KU toward the south and east. In this hour, the Blue Lick transformer (west to east, to the south of Louisville) is highly constraining, resulting in the following LMPs:

Location	LMP ($/MWh)
LG&E Load Zone	28.0
Brown (bus 27009)	43.3
Ghent (bus 27138)	30.4
Green River (bus 27144)	42.1
Mill Creek (bus 27253)	5.7
Paddys Run (bus 27293)	13.4
Trimble (bus 27409)	13.8
Tyrone (bus 27413)	43.4
Petersburg (Indiana)	16.7
Tanners Creek (Ohio)	20.9

In this hour, the Blue Lick constraint depresses prices from Trimble County through the Louisville load area to Mill Creek. Generators to the east and south are downstream from the constraints and have higher LMPs.

Other constraints affecting regional power flows and Kentucky LMPs in this hour include north to south flows from Clifty Creek-to-Northside and across the Petersburg transformer, in southwestern Indiana. See Figures 3 and 4.

Hour 20 on August 21, 2005, shows a similar pattern of LMPs. In this hour, the Blue Lick transformer (southeast of Louisville) is again constraining west to east power flows, resulting in the following LMPs:

Location	**LMP ($/MWh)**
LG&E Load Zone	34.7
Brown (bus 27009)	49.2
Ghent (bus 27138)	33.5
Green River (bus 27144)	47.5
Mill Creek (bus 27253)	11.6
Paddys Run (bus 27293)	18.8
Trimble (bus 27409)	19.1
Tyrone (bus 27413)	48.1
Petersburg (Indiana)	18.5
Tanners Creek (Ohio)	25.7

The average full LMPs at the load buses were higher than those at generation buses in this hour; however, when loss factors are excluded, generation prices exceed load prices so that congestion costs are negative. In this hour, the Blue Lick constraint depresses prices again from Trimble County through the Louisville load area to Mill Creek. But again, the larger generators to the east are downstream from the constraints and have higher LMPs. In this hour, we also see another common constraint on the Kenton-to-Wedonia flowgate located south of the Spurlock plant that is limiting north to south power flows from AEP into LG&E/KU. This constraint also increases LMPs at the Brown station. And, the Petersburg transformer in southwestern Indiana is also constraining regional power flows. See Figures 5 and 6.

Exhibit RRM-
Figure 1 – Supplemental February 21, 2005

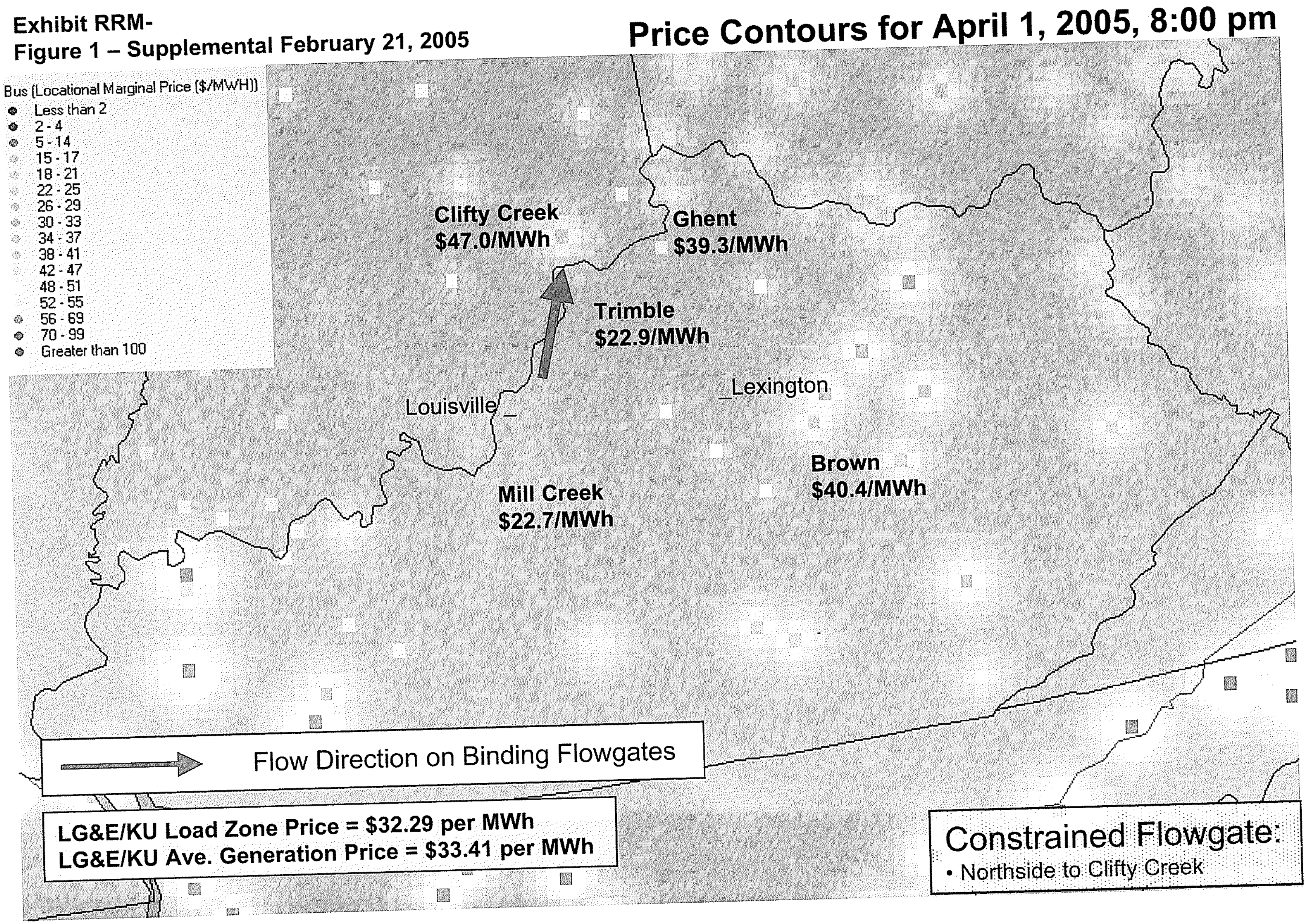
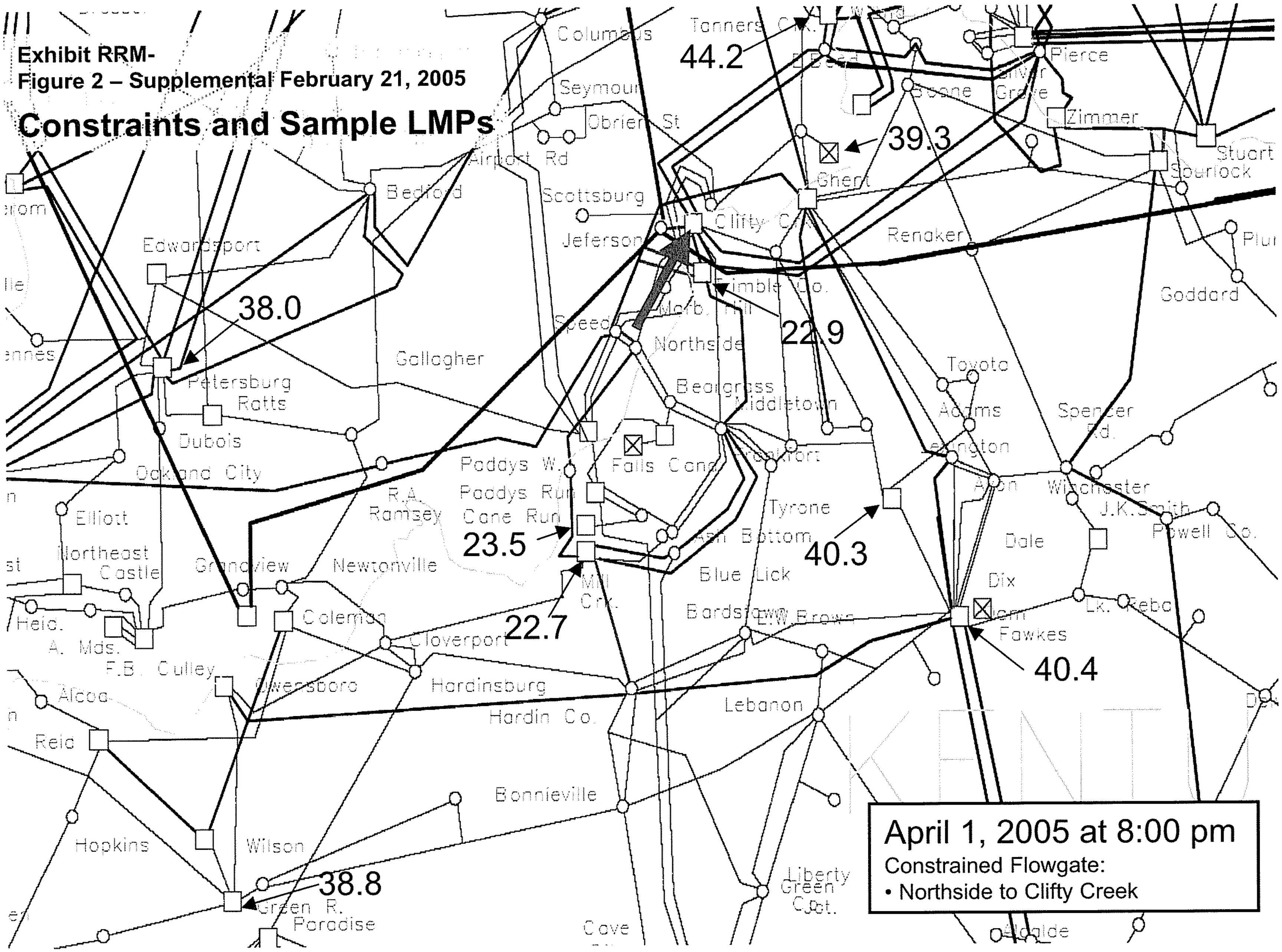


Exhibit RRM-

Figure 2 – Supplemental February 21, 2005

Constraints and Sample LMPs



April 1, 2005 at 8:00 pm

Constrained Flowgate:

- Northside to Clifty Creek

Exhibit RRM-
Figure 3 – Supplemental February 21, 2005

Price Contours for July 2, 2005, 1:00 pm

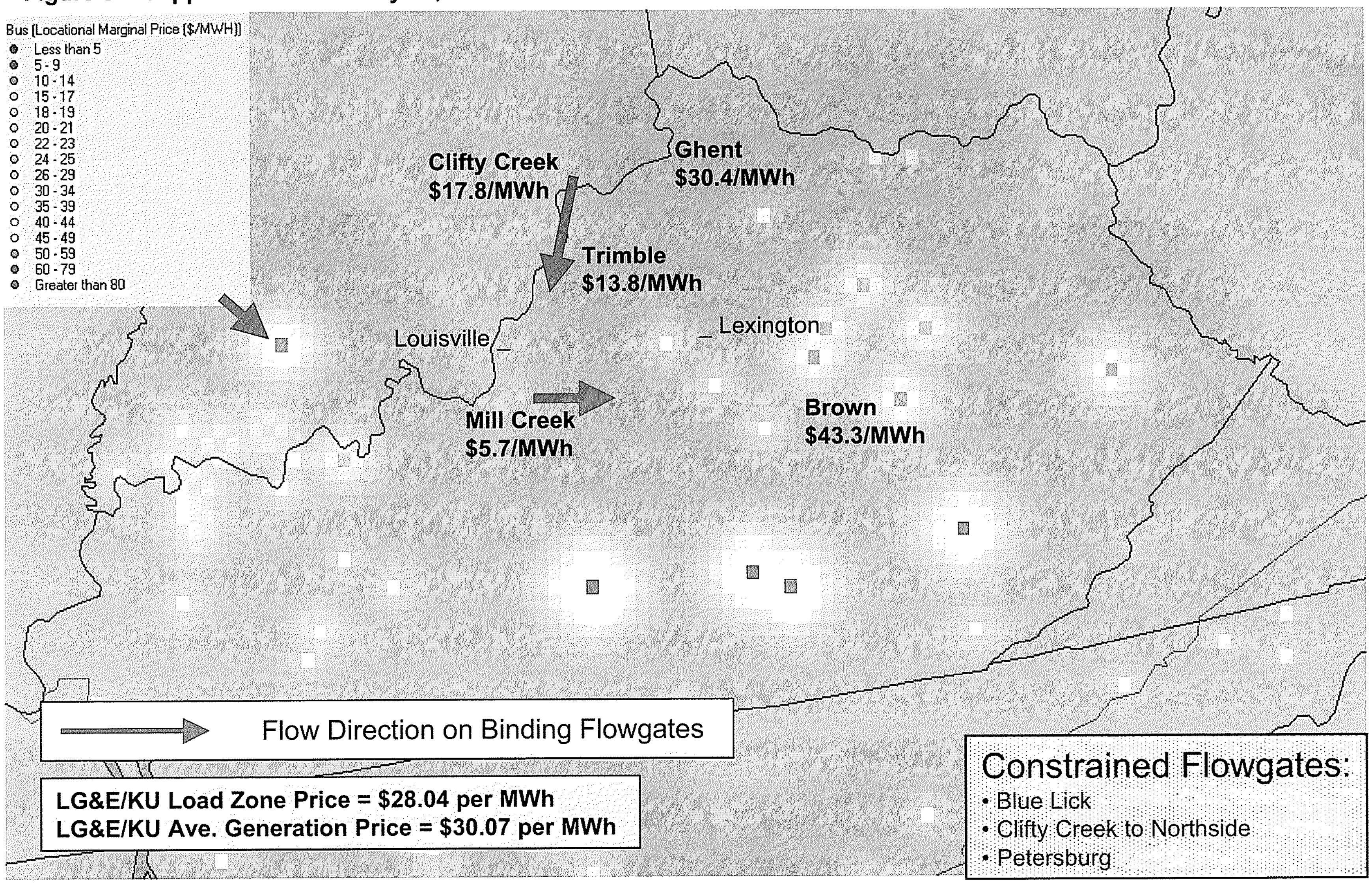


Exhibit RRM-

Figure 4 – Supplemental February 21, 2005

Constraints and Sample LMPs

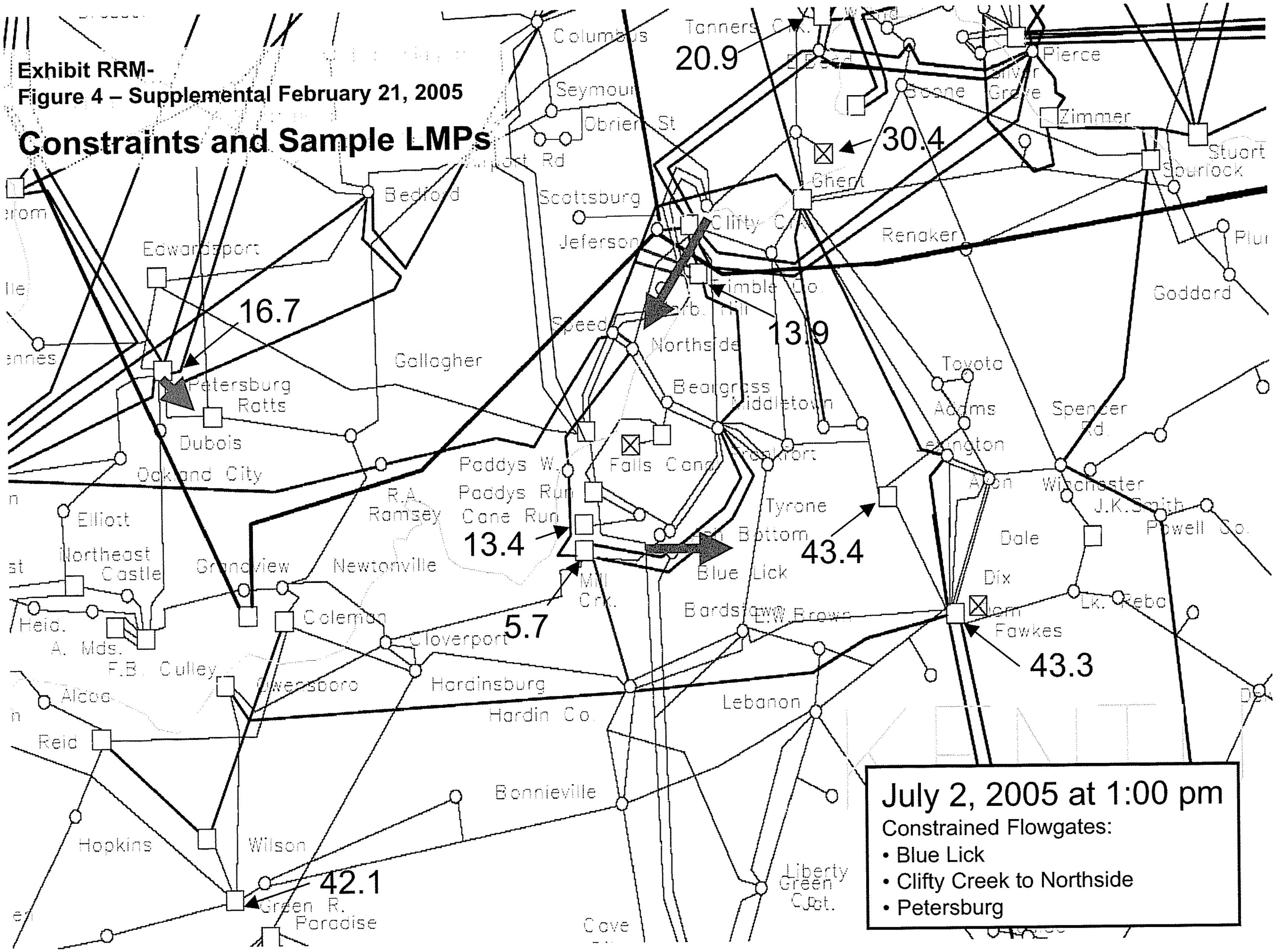


Exhibit RRM-

Figure 5 – Supplemental February 21, 2005

Price Contours for August 21, 2005, 8:00 pm

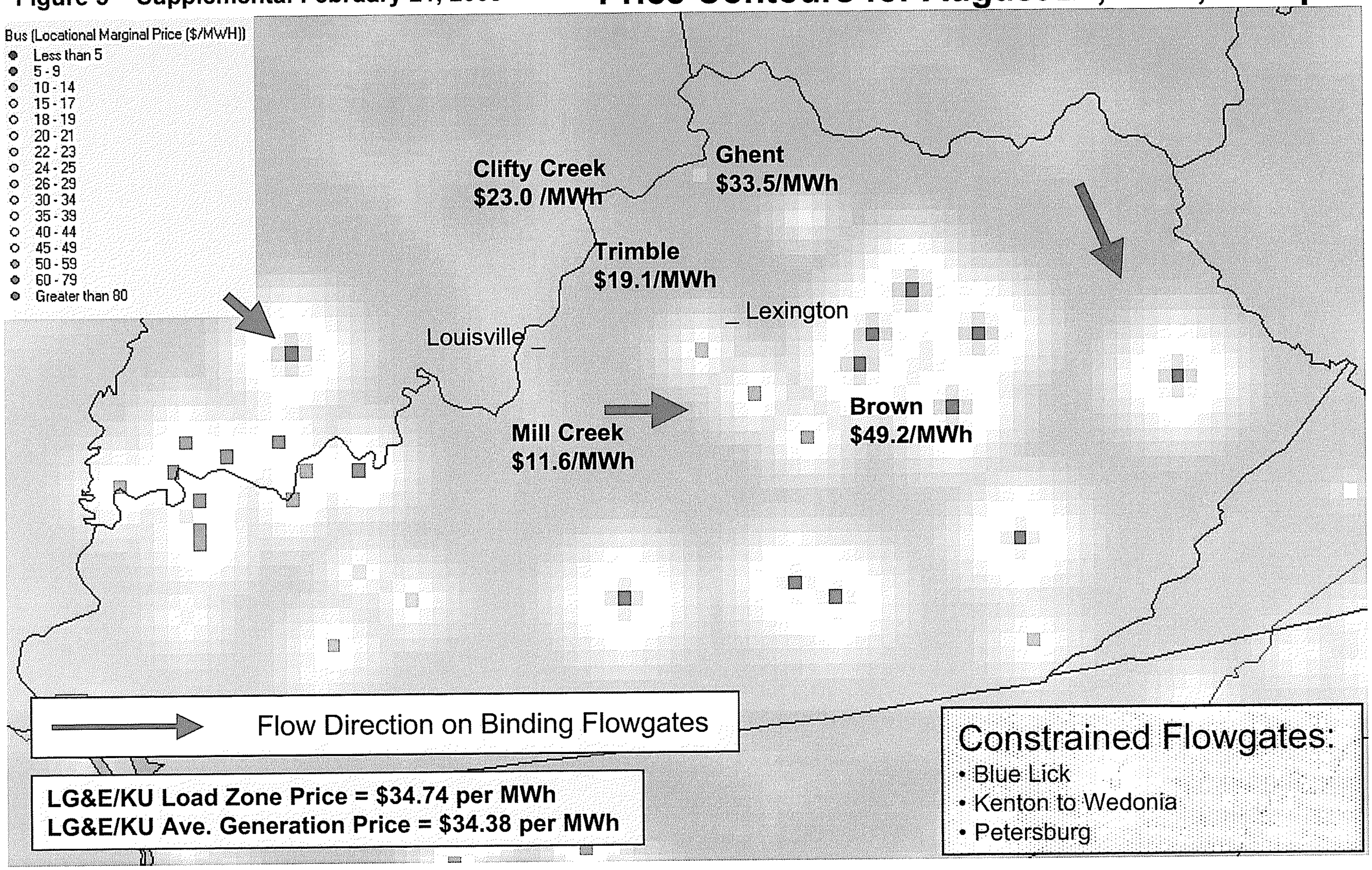
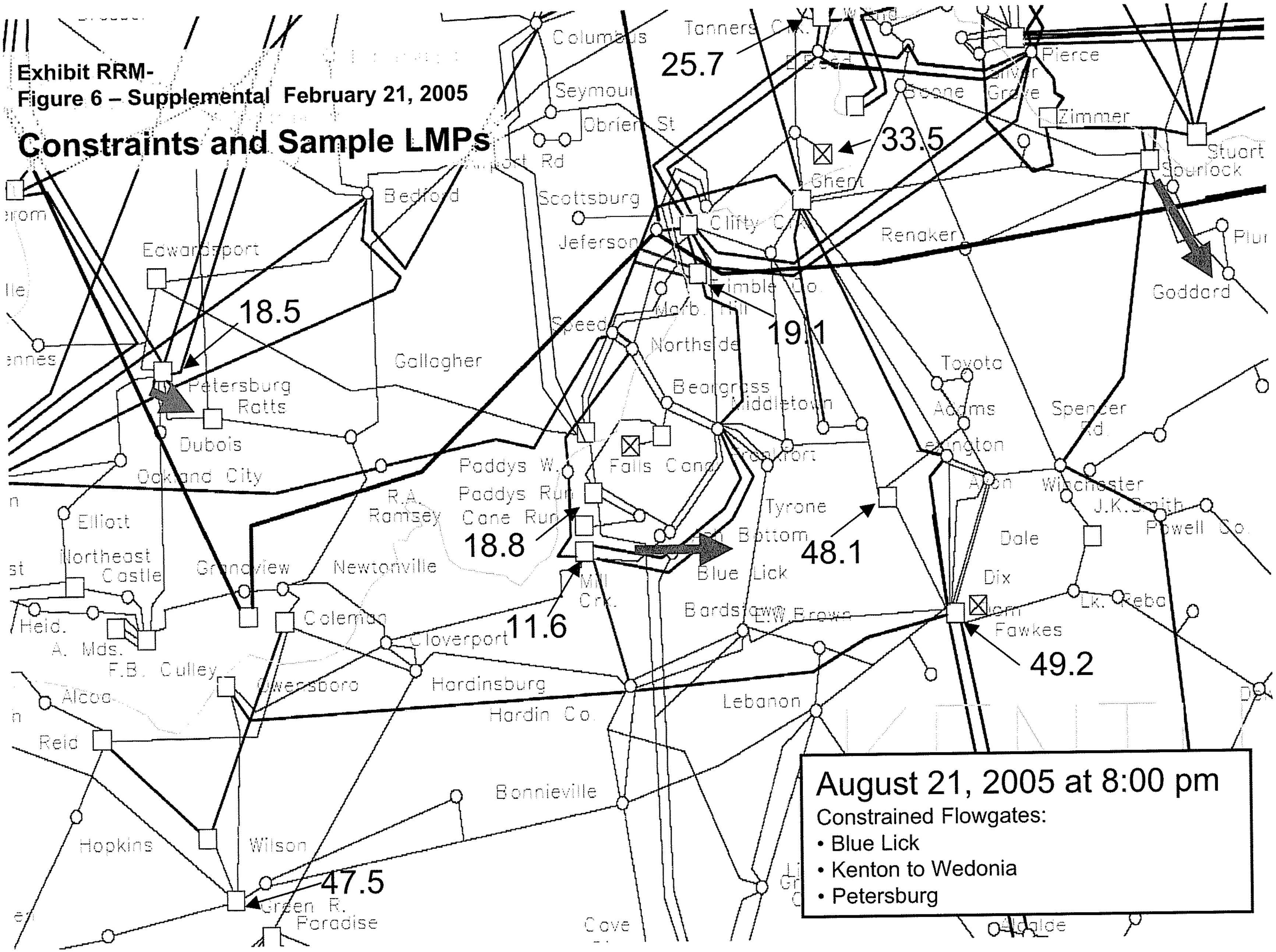


Exhibit RRM-
Figure 6 – Supplemental February 21, 2005

Constraints and Sample LMPs



August 21, 2005 at 8:00 pm

Constrained Flowgates:

- Blue Lick
- Kenton to Wedonia
- Petersburg

ˋ005	Rebuttal Testimony (as Updated) – January 20, 2005			Direct Testimony – December 29, 2003	
Page ˋence	Findings	Basis of Change	Page Reference	Findings	Page Reference
	... if the Companies withdraw to pursue the Transmission Owner – ˋliability Coordinator ˋRC") option, LG&E/KU ıeir customers can ɔt a net annual ase in their costs of ɔe, after deducting the for the TEMT mentation, of $47.7 ı per year.	Analysis was updated to: • Reflect FERC's approval of TEMT and quantify impacts of FERC orders; • Incorporate enhanced power flow model for 2005, replacing 2004 power flow used in Direct Testimony; • Analyze first 2 tiers of actual, supplemented by Tiers 3 and 4 of April 2004 illustrative, FTR allocations; • Expand analysis of TLR events to cover all 2003; • Analyze a broad range of sensitivity cases; and • Incorporate other additional updates.	Page 4, line 18; See also: Page 54, line 6; Page 62, Line 5; Page 63, Lines 5 and 8; Page 64, Line 6	... continued membership [in the Midwest ISO] ... yields on-going net benefits of approximately $12 million per year.	Page 4, Lines 17 – 20.

ry 21, 2005	Rebuttal Testimony (as Updated) – January 20, 2005			Direct Testimony – December 29, 2003	
Page Reference	Findings	Basis of Change	Page Reference	Findings	Page Reference
Page 4, e 7	… the additional exit fee of $40.2 million ….	LG&E / KU no longer able to exit before December 31, 2005 resulting in changes to Exit Fee calculation.	Page 4, Line 19	… the current cost of exiting would be approximately $38.2 million (assuming a withdrawal effective as of December 31, 2004).	Page 4, Lines 16 - 17
	he present value of these term economic cts is $283.3 million.	Reflects net present value of higher annual recurring costs of withdrawing from the Midwest ISO.	Page 4, Line 24; See also: Page 54, Line 12	For the study period (2005 – 2010), the cumulative net benefits accruing to LG&E/KU are estimated to be approximately $95 million.	Page 2, Lines 7 – 9.
	above.	See above.	See above.	See above.	See above.
	bove.	See above.	See above.	See above.	See above.

uary 20, 2005		Direct Testimony – December 29, 2003	
nge	Page Reference	Findings	Page Reference
ty ot been ct ime filing of Adjusts ario for nbership ssion ect no net enue end f base lue based s of actual and Tiers 3 April 2004 allocation.	Page 65, Lines 12 – 21.	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.	Page 6, Lines 5 – 7.

nuary 20, 2005		Direct Testimony – December 29, 2003	
nge	Page Reference	Findings	Page Reference
f final r 2005 le. The he timated 2004 on. al Tier 1 nor the ocations company e at the	Page 64, Line 14 to Page 65, Line 5	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.	Exhibit RRM-1, at Page 12 – 13.

LG&E ENERGY

LG&E Energy LLC
220 West Main Street (40202)
P.O. Box 32030
Louisville, Kentucky 40232

May 28, 2004

Federal Energy Regulatory Commission
Form No. 714
Room 83-14
888 First Street, N. E.
Washington, D. C. 20426

RE: FERC Form 714

Dear Commissioners:

Louisville Gas and Electric Company and Kentucky Utilities Company herein jointly file

ad Planning Area Report
December 31, 2003

cation and Certification

3. Respondent Mailing Address:
Louisville Gas & Electric Co.
P.O. Box 32020
Louisville, KY 40232

4. Contact Person:

Name: Elaine C. Welsh
Title: Interchange Transactions Analyst
E-mail address: Elaine.Welsh@LGEEnergy.com
Telephone #: 502.627.3578 Ext.

5. Certifying Official:

Name: Mark S. Johnson
Title: Director, Transmission

Signature: Date: 5/25/04

JUN 30 2004

nd Planning Area Report
December 31, 2003

Please Type:
Utility Code
Utility Name

s Included In Reporting Control Area
sheets if needed)

d or for which the required information is otherwise available to control area operators and (2) dynamically scheduled plants or
r standby status. Provide totals for columns (d) and (e) as a last line. The total in column (d) should equal the value in column
r the month of the annual peak demand. Any differences must be explained in a note. For specific guidelines, please refer to the

Plant Available Capability at the Hour of the Annual Peak Demand Based on Net Energy for Load (MW) (d)	Integrated Net Load on the Plant at the Hour of the Annual Peak Demand Based on Net Energy for Load (MW) (e)
566	551
1479	1470
36	36
193	118
833	773
22	22
14	0
1910	1854
1546	970
207	54
129	71
36	0
0 0 0	0 0 0
414	405
7385	6324

nd Planning Area Report
December 31, 2003

Please Type:
Utility Code
Utility Name

apabilities at Time of Monthly Peak Demand

lease first read the instructions, then complete this Schedule. The value in column (c) for the month of the annual peak demand

ak Demand, Based on Control Area Net Energy For Load (NEL)

	External to the Control Area Net Unit or Firm Capability (MW)		
Total (c + d + e + f) (MW) (g)	Available (MW) (h)	Not Available (MW) (i)	Total Capability (g + h + i) (MW) (j)
7325	200	0	7525
7002	167	33	7202
6287	167	33	6487
7110	167	33	7310
7349	152	48	7549
7442	200	0	7642
7186	200	0	7386
7408	200	0	7608
7203	60	140	7403
7446	45	155	7646
7449	100	100	7649
7378	200	0	7578

ak:

nd Planning Area Report
December 31, 2003

Please Type:
Utility Code
Utility Name

or Load and Peak Demand Sources by Month

ternally including control area losses. The total in column (d) should equal the difference in the
demand should equal the total in column (e) in Schedule 1. Any differences must be explained in
ges 19 and 20.

Load Sources at Time of Control Area Monthly Peak Demand, Based on Net Energy For Load (NEL)					
of Plants	Unit or Firm Purchases (MW) (g)	Unit or Firm Sales (MW) (h)	Net Non-Firm & Inadvertent (MW) (i)	Monthly Peak Demand (MW) (f+g-h+i) (j)	Monthly Minimum Demand (MW) (k)
	602	746	-122	5706	2491
	1377	584	-173	5026	2876
	967	556	-158	4700	2417
	1183	879	-142	4382	3704
	851	524	-130	4647	2147
	1315	1260	-220	5727	2246
	1176	1104	-248	6032	2655
	1334	1055	-210	6393	2761
	632	1300	-146	5224	2326
	1135	1929	-129	4100	2341
	1598	1815	-88	4585	2326
	1255	1383	-140	4960	2800

Planning Area Report
ember 31, 2003

Please Type:
Utility Code:
Utility Name:

trol Area Interconnections

area is interconnected in column (b), all the interconnection line
n (d). See Schedule 4 instructions on page 20 and 21.

Control Area Interconnection Line or Bus Names (C)	Line or Bus Voltage (kV) (d)
- 3816	138KV
- 4542	345KV
t - Line 3850	138KV
k - Line 1682	138KV
t - 3852 & 3854	138KV
- Line 6658	69KV
m - Line - 6601	69KV
m Sub - LaGrange 6686-6687	69KV
ville - Louisville 3882	138KV
- Line 3881	138KV
Run - Gallagher 3827	138KV
t - Line 3853	138KV
5401	161KV
r RECC - 6667 - 6662	69KV

lanning Area Report
ember 31, 2003

Please Type:
Utility Code:
Utility Name:

trol Area Interconnections

area is interconnected in column (b), all the interconnection line
n (d). See Schedule 4 instructions on page 20 and 21.

Control Area Interconnection Line or Bus Names (C)	Line or Bus Voltage (kV) (d)
Hillsboro	138KV
o Morehead	69KV
er to Wilson	161KV
rg to Hardinsburg	138KV
o Beattyville/Powell County	161KV
o Tyner	161KV
ooper	161KV
o Marion County	161KV
to Delvinta/Powell County	161/69 KV
to Laurel County/Tyner	161/69
unty to Green County/Marion County	161/69
Fawkes	138
Gallatin County	138KV
to Goddard	138
Spurlock	138KV
Spurlock	138
venue to Avon	138KV
to Skaggs	138
n/Etown to Nelson County	138/69
e to Bonnieville	138/69
ro North to Avon/Dale	138/69
ott County to Owen County	138/69
Penn	69KV

Please Type:
Utility Code:
Utility Name:

lanning Area Report
mber 31, 2003

trol Area Interconnections

area is interconnected in column (b), all the interconnection line
n (d). See Schedule 4 instructions on page 20 and 21.

Control Area Interconnection Line or Bus Names (C)	Line or Bus Voltage (kV) (d)
to Beattyville	69
Industrial to East Bardstown	69
l to North Springfield	69
Owen County	69
to Bracken County	69
to Hunters Bottom	69
ge to Clay Village	69
Switching to Renaker	69
to Stephensburg	69
own to kargle	69
own to Tharp	69
South Corbin	69
Hickory Plain	69
South to Somerset	69
rg to Green County	69
le to Hodgenville	69
to Laurel County	69
Murphysville	69
n to Hodgenville	69
le to Vne Grove	69
Murphysville	69
Bracken County	69
t South to Somerset	69
d to North Springfield	69
derwear to Sewellton	69
ott County to Owen County	138/69
Penn	69KV

Planning Area Report
ember 31, 2003

Please Type:
Utility Code:
Utility Name:

trol Area Interconnections

area is interconnected in column (b), all the interconnection line
in (d). See Schedule 4 instructions on page 20 and 21.

Control Area Interconnection Line or Bus Names (C)	Line or Bus Voltage (kV) (d)
er Steel to Cloverport	138
rg to Cloverport	138
Simpsonville to Middletown	69
lle to Eastwood	69
to Clifty Creek	138
rth to Phipps Bend	500
County to Calvert City	161
County to Kentucky Dam	161
Switching to Pineville	161
o Pineville	161/69
South to Kentucky Dam	69
South/Princeton to Kentucky Dam	69

5C

nd Planning Area Report
December 31, 2003

Please Type:
Utility Code
Utility Name

hedule 5.
and Actual Interchange

umn (b); the total annual megawatthours (MWh) of the scheduled interchange that were received by the respondent control area
a, in column (d); the MWh of total annual actual interchange received and delivered within each adjacent control area, in columns
umn (d) on Schedule 3. Any difference must be explained in a note. See Schedule 5 Instructions on page 21.

Scheduled Interchange Between Control Areas (MWh)		Actual Interchange Between Adjacent Control Areas (MWh)	
Received (c)	Delivered (d)	Received (e)	Delivered (f)
		2940	657073
		2157147	516884
		2478006	2909390
		724943	3050
		839923	1670145
		173310	12828
		898684	1985903
		6192515	7351104
11294280	9678769	0	0
11294280	9678769	13467468	15086377

Electric System Report ecember 31, 2003	Please Type: Utility Code Utility Name

Area System Lambda Data

Provide, as a note in Part IV, an explanation describing the reason for the unavailability of system lambda information and a definite plan for reporting the information with a target date. The Commission expects that all Energy Management Systems, with proper instructions, can record the system lambda being used for economic dispatch of the control area's thermal units.

Respondents should be able to report system lambda, along with the other information reported on a control area basis, that describe the operation of such areas from information that should be readily available. The Commission is not requesting Respondents to develop incremental or marginal cost (either short or long term) according to any formula. Nor is the Commission requesting "avoided cost rates" that, pursuant to PURPA 210, electric utilities file with state commissions or otherwise make available for prospective qualified facilities.

Description of Economic Dispatch. Also, provide in writing a detailed description of how Respondent calculates system lambda. For those systems that do not use an economic dispatch algorithm and do not have a system lambda, provide in writing a detailed description of how control area resources are efficiently dispatched.

ts that they consider "dispatchable." Therefore the costs to be minimized could

to operate at the same incremental fuel cost as the other units and, thus, those

nd Planning Area Report
December 31, 2003

Please Type:
Utility Code
Utility Name

s That Compose the Planning Area
sheets if needed)

port is being prepared and their coincident summer and winter peak demands in megawatts.

	Electric Utility Coincident Peak Demand (MW)	
	Summer (c)	Winter (d)
	2583	1823
	3810	3889

nd Planning Area Report
December 31, 2003

Please Type:
Utility Code
Utility Name

hedule 2.
l Winter Peak Demand and Annual Net Energy for Load

Respondents must submit on a 3.5 inch diskette or CD formatted for he DOS operating system the following data file in ASCII format: the lanning area's actual hourly demand, in megawatts, for each hour of he year starting with 1 a.m, January 1, 2003. Indicate the time zone nd the period for which daylight savings time was used. The file hould have 8760 records (8784 for leap years). For hours when this nformation is not available, enter "NA."

PLANNING AREA FORECAST SUMMER AND WINTER PEAK DEMAND

Provide on the diskette a file containing the planning area's forecast ummer and winter peak demand, in megawatts, and annual net nergy for load, in megawatthours, for the next ten years.

PLANNING AREA FORECAST SUMMER AND WINTER PEAK DEMAND
Part III - Schedule 2

	Summer Peak		Winter Peak		Net Energy for Load	
	LGE	KU	LGE	KU	LGE	KU
2003	2,807	4,180	1,879	3,967	11,992,000	20,212,000
2004	2,865	4,300	1,910	4,091	12,168,000	20,716,000
2005	2,925	4,384	1,940	4,160	12,368,000	21,092,000
2006	2,985	4,471	1,971	4,254	12,578,000	21,496,000
2007	3,044	4,543	2,001	4,324	13,015,000	21,931,000
2008	3,103	4,609	2,031	4,417	13,235,000	22,366,000
2009	3,162	4,698	2,061	4,521	13,468,000	22,804,000
2010	3,221	4,807	2,091	4,628	14,460,000	23,259,000
2011	3,279	4,903	2,120	4,692	14,705,820	23,654,403
2012	3,336	4,983	2,148	4,798	14,950,453	24,103,837

Each value of system lambda, i.e. the incremental cost of delivered power, in the file labeled LAMBDA.DAT on the enclosed diskette is calculated by the electric load dispatch computer for those units which are under economic dispatch and control and is based on the average cost of all fuel (including transportation and handling) of each type (coal, gas, or oil) purchased during the preceding month.

The values of system lambda do not include incremental operation and maintenance expenses.

ECAR Data Release Authorization

FERC Form 714
Annual Electric Control and Planning Area Report
Part III, Schedule 2

Respondent **LGEE (Louisville Gas & Electric and Kentucky Utilities)**
is a Member of the East Central Area Reliability Coordination Agreement (ECAR).
ECAR, on behalf of the respondent, will release the historical hourly load data to FERC to satify the hourly load data reporting requirements of FERC Form 714, Part III, Schedule 2. The respondent's hourly load data will also be included in an aggregation of ECAR hourly load which will be available for release to the public.

Requests for hourly load data should be forwarded to ECAR for disposition. Requests for individual company hourly load data by non-ECAR entities will be fulfilled upon receipt of a written request and payment of processing fees. Requests for individual company hourly load data by ECAR members only, and any request for ECAR aggregate load data, will be fulfilled electronically for free.

Please complete the bottom section of this authorization form

	2006	2007	2008	2009	2010
50,839	$14,150,839	$14,150,839	$14,150,839	$14,150,839	$14,150,839
81,398	$34,481,398	$34,481,398	$34,481,398	$34,481,398	$34,481,398
57,096	$1,957,096	$1,957,096	$1,957,096	$1,957,096	$1,957,096
20,000	$2,620,000	$2,620,000	$2,620,000	$2,620,000	$2,620,000
9,333	***$53,209,333***	***$53,209,333***	***$53,209,333***	***$53,209,333***	***$53,209,333***
39,034					
40,000	$1,840,000	$1,840,000	$1,840,000	$1,840,000	$1,840,000
91,984	$9,991,984	$9,991,984	$9,991,984	$9,991,984	$9,991,984
03,326	$15,903,326	$15,903,326	$15,903,326	$15,903,326	$15,903,326
98,312	$14,498,312	$14,498,312	$14,498,312	$14,498,312	$14,498,312
12,553	$67,912,553	$67,912,553	$67,912,553	$67,912,553	$67,912,553
5,209	***$110,146,175***	***$110,146,175***	***$110,146,175***	***$110,146,175***	***$110,146,175***
75,875	**$56,936,841**	**$56,936,841**	**$56,936,841**	**$56,936,841**	**$56,936,841**
75,875	**$154,112,717**	**$211,049,558**	**$267,986,400**	**$324,923,241**	**$381,860,083**
5,875	**$53,212,001**	**$49,730,842**	**$46,477,423**	**$43,436,844**	**$40,595,181**
5,875	**$150,387,877**	**$200,118,719**	**$246,596,142**	**$290,032,986**	**$330,628,167**

Exhibit RRM -
Table 2B
Summary of Near Term Annual Recurring Benefits and Costs - Companies' Resources - February 21, 2005

Category	Base Case LG&E / KU in MISO	LG&E / KU Out of MISO TORC Option	Cost of TORC Option Compared to Remaining in MISO
Costs			
RTO Administrative Costs			
Schedule 10, 16, and 17 Charges	$14,150,839	-	
Subtotal	***$14,150,839***	***$0***	***-$14,150,839***
Generation & Purchased Power Costs			
Native Load			
Fuel Costs	$412,727,180	$420,533,873	
Fixed O&M Costs	$152,327,658	$152,894,398	
Variable O&M Costs	$32,138,445	$32,171,000	
Emissions Costs	$115,585,961	$118,304,262	
Purchased Power Costs	$89,077,366	$87,945,061	
Subtotal	***$801,856,610***	***$811,848,594***	***$9,991,984***
Off-System Sales			
Fuel Costs	$113,954,078	$77,400,610	
Fixed O&M Costs	$1,239,720	$806,620	
Variable O&M Costs	$7,844,903	$5,275,458	
Emissions Costs	$35,317,416	$22,633,059	
Purchased Power Costs	-$509,126	-$579,375	
Subtotal	***$157,846,991***	***$105,536,372***	***-$52,310,619***
Transmission Usage Costs			
Transmission Payments on Off-System Sales	presented Net of Transmission Payments		
Transmission Congestion Costs	$34,481,398	-	
Subtotal	***$34,481,398***	***$0***	***-$34,481,398***