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8. RESOURCE ASSESSMENT AND ACQUISITION PLAN.

8.(1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.

A principal criterion in the development of this resource plan was to maintain flexibility, be able to respond to changing conditions and adequately provide for a reliable system now and in the future. The plan, shown year-by-year in Section 5.(4), provides dates for specific resource acquisitions. Resource planning is an ongoing process, and changes in assumptions, technology, market conditions, and the needs of our customers are inevitable. This Integrated Resource Plan ("IRP") is part of an ongoing process involving continuous assessment of resource options in the context of changing utility needs and new information.

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs. This process involves: 1) establishment of a target reserve margin criterion, 2) assessment of the adequacy of existing generating units and existing purchase power agreements, 3) assessment of potential purchase power suppliers, 4) assessment of demand-side options, 5) assessment of supply-side options, and 6) development of an economic plan from the available resource options.

A study was performed to determine an optimal reserve margin criterion to be used by the Companies. This study indicated that an optimal target reserve margin in the range of 12% to 14% would provide an adequate and reliable system to meet customers' demand under a wide range of sensitivities to key assumptions. In the development of the optimal IRP, the Companies maintained a reserve margin target of 14%. Additional detail on the development of this criterion is contained in the report titled *2005 Analysis of Reserve Margin Planning Criterion* (January 2005) contained in Volume III, Technical Appendix.

Existing capacity resources are composed of KU- and LG&E-owned generating units and three purchase power agreements: Electric Energy Incorporated ("EEInc."), Owensboro Municipal Utilities ("OMU"), and Ohio Valley Electric Corporation ("OVEC"). Further discussion of the future changes to the percent sponsorship of OVEC units is covered in Section 6 under OVEC. The Companies' self-owned generation fleet has expanded to include four new jointly owned combustion turbines: two units were commissioned on June 1, 2004 as Trimble County Units 7 and 8, and the other two units were commissioned on July 1, 2004 as Trimble County Units 9 and 10 (Case No. 2002-00381).

As part of this IRP, the technological status, construction aspects, operating costs, and environmental features of various generation plant construction options were reviewed. After screening many technologies, six generation plant construction options were evaluated using resource planning computer models. Along with these supply-side options, the five DSM programs that passed the screening analysis were included in the integrated analysis. The optimal IRP recommends the construction of a second coal unit at Trimble County, six Greenfield combustion turbines, the Purchase Power Agreement ("PPA") with W.V. Hydro, Inc. ("WV Hydro"), and one supercritical Greenfield coal unit. Also, there is the implementation of five new DSM programs targeting both residential and commercial entities, which ramp up to a combined amount of 28.8 MW annually in 2011. Section 8.(5)(c) summarizes the study in more detail.

Pending Legislation

Uncertainty remains constant in reference to the U.S. energy policy legislation. The Senate is planning a last attempt at a comprehensive energy bill to be worked on early in the Congressional session in 2005. Regarding energy efficiency and Demand Side Management, both versions of the bill include reauthorizing the Energy Star program, and both support energy-related tax credits. The impact on the plan due to the legislation discussed above is unclear. The Companies will continue to monitor the progress of the proposed legislation.

Following the August 14, 2003 blackout in the Northeast, the North American Electric Reliability Council ("NERC") established actions a year later to be taken in both the U.S. and in Canada. As one of the action items identified by the Task Force, readiness audits have been conducted at some of the largest utilities, including KU and LG&E utilities.

Some of the future challenges for NERC as a result of the Task Force findings include enactment of reliability legislation by the U.S. Congress, completion of revision of NERC's existing standards, reform of the roles/responsibilities/boundaries for regional councils, and other enhancements. Hence, this alludes to further legislation not currently even listed as pending.

FERC released the Policy Statement on Matters Related to Bulk Power System Reliability On April 19, 2004 (Docket No. RM04-2-000), the latest regulatory initiative designed to promote reliable transmission service in interstate commerce, as a direct result of the Final Blackout Reports issued by the Task Force. This Statement includes clarifying FERC policy with regard to the following: the need to expeditiously modify existing bulk power system reliability standards—to translate them into clear and enforceable requirements, to ensure public utility compliance with industry reliability standards and possible FERC action to address specific bulk power system reliability issues, the cost recovery of prudent bulk power system reliability expenditures, consideration of reliability in FERC decision-making, and limitations on liability. Additionally, in that Statement, FERC strongly supports legislative reform to provide a clear Federal framework for developing and enforcing mandatory reliability rules. Until such legislature is established, FERC is taking steps within its existing authority to promote greater reliability of the U.S. bulk power system and its operation, and supports industrial efforts to improve the current voluntary industry-based approach.

8.(2) The utility shall describe and discuss all options considered for inclusion in the plan including:

The Companies' strategy to acquire additional resources was developed after a thorough evaluation of both demand and supply-side alternatives. This section contains a description and discussion of the options considered during the development of the Companies' optimal IRP.

8.(2)(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;

Generation

Maintenance Schedules

The Companies continue to evaluate potential improvements (economic and otherwise) through routine maintenance of their generation fleet. Maintenance schedules are coordinated across the combined KU and LG&E generation system such that the outages will have the least economic impact to the customers and the Companies.

With two exceptions, the Companies' continue to plan three-week boiler outages each year to keep their units running efficiently through the year. The exceptions apply to the Trimble County and Mill Creek units, which are now subject to biennial four-week outages. Additionally, the Mill Creek units are scheduled off for one week in the year between the years with the four-week outages. The target seven-year cycle for performing major maintenance continues to be successful for the Companies. As inspections reveal potential problems, various boiler and turbine components are repaired or replaced. If equipment enhancements are available they are analyzed and installed when found to be the prudent option.

Outages for shared units, namely Trimble County Unit 1 and OMU's Smith Units 1 and 2, are compiled by the Companies and shared with the respective owners involved. With Trimble County Unit 1 being 75% owned by LG&E, LG&E is given preference as to when Trimble County Unit 1 outage is scheduled. Joint owners IMEA and IMPA (12.12% and 12.88% ownership) are informed of any schedule changes. On the other hand, OMU informs the Companies as to the duration of outage needed on Smith Units 1 and 2, as well as the frequency of major overhauls. Then, the Smith unit outages are optimized together with the Companies' unit outages and schedules are checked with OMU prior to the schedule becoming the approved budget schedule.

Efficiency Improvements

Since the Companies 2002 Joint IRP, the Companies have proceeded with several activities that have improved generation efficiencies. These have included the latest controls technologies, boiler tube replacements, pulverizer rebuilds, boiler chemical cleans, precipitator rebuilds, and cooling tower rebuilds.

Technologically advanced controls continue to be added in the fleet. State-of-the-art process control technology application has been, and will continue to be, the main efficiency improvement of the generating stations. New control technologies allow for tighter control of key operating parameters and provide for optimization of integrated systems not previously available with analog controls. New distributive control systems ("DCS") have been added to or improved on Trimble County Unit 1 boiler, Brown Unit 1 boiler, Green River Units 3 and 4, and Mill Creek Unit 3. Transistor controlled voltage regulator cabinets have replaced rheostat controlled voltage regulator cabinets at Ghent, Green River, Mill Creek, and Cane Run stations.

Several state-of-the-art actuators have replaced pneumatic actuators on dampers and pump speed controls. These improvements give much tighter control and provide more operational information, resulting in faster response and higher efficiency.

The largest contributor to the fleet's equivalent forced outage rate ("EFOR") has been boiler tube failures. As native load has increased, so has the demand upon boiler load. Though equipment is aging, units are still required to run at peak capacity. To insure maximum availability, boiler tube studies and inspections have been conducted, using the latest technology, to identify boiler sections which need replacement. All units across the fleet have scheduled boiler outages to replace boiler tube sections. These efforts will insure maximum boiler availability and reliability. Several unit boilers have had chemical cleans to remove the potential of having tube ruptures due to overheating. Specifically, Ghent Units 1, 2, and 3 were cleaned in 2003; Mill Creek Unit 4 was cleaned in 2004; and Cane Run Units 4 and 5 were chemically cleaned in 2004. The policy is to clean boilers when their deposit weight density (a measure of the amount of scale on the inside of a boiler tube) exceeds 20 grams per square foot; this policy is in line with guidelines of Electric Power Research Institute ("EPRI").

The changes in coal supply and coal burner modifications to reduce gaseous emissions have negatively impacted precipitator performance. To insure compliance to particulate emission standards, a number of units have had precipitator rebuilds (either partial or complete): Cane Run Unit 5, Mill Creek Unit 3, Brown Unit 3, and Brown Unit 1. Other units have improved and modernized precipitator controls: Mill Creek Unit 2 and Trimble County Unit 1. These modifications have reduced incidences of load restriction initiated to maintain opacity emission compliance.

Other efforts to increase efficiency and reduce derates have been pulverizer rebuilds performed through the fleet, the wet stack conversion projects on the Mill Creek Units (as mentioned previously in the Companies 2002 Joint IRP), and air heater basket replacement. Aging cooling towers have been rebuilt using modern polymer technology and fill design to insure availability and improve heat transfer. The rebuilds have included Brown Units 1 and 3, Mill Creek Unit 1, and Ghent Units 1 and 4. Cane Run, Mill Creek, Green River and Ghent ash pond dikes have been raised to accommodate more waste material. A combination of creative selling of byproducts and the vertical extension of pond dikes will extend the life of the ponds, thereby assisting in the effort to control generation costs. Replacement of air heater baskets on Brown Unit 3 and Cane Run Unit 5 has improved heat transfer and reduced the risk of forced outages. Inspection of these units had revealed age-related corrosion of air heater baskets.

Additionally, there have been several environmentally related projects which have helped maintain the integrity and accuracy of data. The flow meters have been changed and standardized at all the stations to an ultrasonic type in order to provide more accurate data results. Secondly, the SO_2 and NO_x monitors on every unit's continuous emissions monitoring system ("CEMS") have been changed. Lastly, the CO_2 monitors were also replaced on the CEMS of every unit. All these monitors were of 1990's vintage, which is close to their expected useful life of ten years of service. The newer monitors include more diagnostic features as well.

Rehabilitation of Ohio Falls

The Companies have evaluated and will continue to evaluate the sustainable long-term generation and modernization needs and opportunities for the Ohio Falls Hydro generation facility. This evaluation considered several economic options and has been an ongoing process.

The 2002 IRP identified that LG&E had filed the formal "Notice of Intent" to relicense the facility with the Federal Energy Regulatory Commission ("FERC") in November of 2000. Currently, the Ohio Falls Station has a 30-year license (granted by the FERC) that will expire in November of 2005. LG&E filed an Application for License Renewal with FERC on October 7, 2003. The relicensing process is underway with the current relicensing schedule anticipating a FERC decision in October 2005. On March 5, 2005, LG&E officially requested the new license from FERC have a term of 40 years.

The current evaluation of the Ohio Falls Station shows that the most economical decision at this time is to plan to rehabilitate each of the eight hydro units, one per year, beginning in 2005 subject to FERC approval. Therefore, the base assumption for modeling the Ohio Falls generation is that the rehabilitation will take place. The Companies continually evaluate resources available to meet load obligations, including the options at the Ohio Falls station. Hence, the current plans will be reevaluated prior to each unit being rehabilitated and as the Companies learn from the condition of the units as the rehabilitation progresses one unit at a time. Further details on this project have been discussed in Section 6 in a subsection titled Rehabilitation of Ohio Falls.

Transmission

The primary purpose of the Companies' (KU and LG&E) transmission system is to reliably transmit electrical energy from Company-owned generating sources to native load customers. The transmission system is designed to deliver Company-owned generator output and emergency generation to meet projected customer demands and to provide contracted long-term firm transmission services. Interconnections have been established with other utilities to increase the reliability of the transmission system and to provide potential access to other economic and emergency generating sources for native load customers. The transmission system is planned to withstand simultaneous forced outages of a generator and a transmission facility during peak conditions.

The Companies routinely identify transmission construction projects and upgrades required to maintain the adequacy of its transmission system to meet projected customer demands. The construction projects currently identified are included in Volume III, Technical Appendix under the section labeled *Transmission Projects*.

Distribution

Distribution Planning standards and guidelines are developed and maintained by the Distribution System Analysis and Planning Group of Distribution Operations' Asset Management Organization. Common guidelines and standards are in use for both the LG&E and KU service areas.

KU and LG&E have continued to install capacitors on the distribution system to provide more efficient use of substation transformer capacity, provide power factor correction in support of the transmission system, and reduce system losses. KU and LG&E plan to continue this practice as studies identify where power factor correction would most benefit the system, taking into account the cost of installation and the resulting savings in capacity and energy. A major project began in 2004 to purchase and install approximately 110,000 kvar of capacitors on the KU distribution system.

Continued productivity enhancements are expected as the GEMINI project is completed by 2005. GEMINI will implement a standard work management, outage management, design tool, and mapping system for both KU and LG&E. These applications will enable streamlined business processes and data integration between critical Distribution Operation systems. Outage Management will allow Distribution Operations to efficiently manage crews during a storm and provide better communications back to the customer. Also, improved design tools will help standardize the design process resulting in efficiency gains in the new business project planning and construction processes.

Substation Construction and Maintenance has fully implemented a Reliability Centered Maintenance ("RCM") program. This philosophy has resulted in a lower cost maintenance program, with the emphasis on condition based preventive maintenance and test policies, and the elimination of routine, time-based equipment overhauls and intrusive diagnostic tests.

The distribution system has been enhanced over the past three years through new substation construction, existing substation expansion, and system reconstruction driven by customer load growth and reliability improvement initiatives. Use of computer-based planning tools and system models allow for analysis of various enhancement opportunities and selection of the best value option for new construction and system enhancements.

Future plans include similar work as recommended by the Electric Distribution Analysis and Planning and the Distribution Operations groups. All recommendations are reviewed and discussed annually by an Investment Plan Review Committee to ensure economical resolution of identified problems requiring minimum practical revenue from the customers.

8.(2)(b) Conservation and load management or other demand-side programs not already in place;

The IRP for the Companies includes five DSM program as options for meeting future customer demand. Two of the potential programs are load management in nature. Setback Thermostats are viewed as a complimentary addition to the existing Demand Conservation program. Smart Thermostats (with TOU rates) may be implemented as a pilot program to support the planned "Real Time" rate pilot program that was approved in the Commission order in Case 2003-00433 . As with many DSM programs there are uncertainties surrounding implementation of the programs. Additional detail on this DSM alternative considered for inclusion in the plan is contained in the report titled *Screening of Demand-Side Management (DSM) Options* (April 2005) contained in Volume III, Technical Appendix.

8.(2)(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and

The economics and practicality of supply-side options were carefully examined to develop an IRP to meet the Companies' customer's expected needs. Various supply-side options, including both mature and emerging technologies, were evaluated as part of the integrated resource planning process. Table 8.(2)(c) contains unit data for each supply-side option reviewed. Additional detail on this process is contained in the report titled *Analysis of Supply-Side Technology Alternatives* (November 2004) contained in Volume III, Technical Appendix.

An assessment of economic opportunities for coordination with other utilities in constructing and operating new units was provided to the Commission on June 28, 2002, in response to the Commission's December 20, 2001 Order in Administrative Case No. 387. The Companies, in a joint response with the other major jurisdictional utilities in the Commonwealth, addressed issues relating to the coordination of maintenance schedules and to joint ownership of baseload generating units. The filed response indicated that the two proposed alternatives did not represent a practicable means of achieving the Commission's goals. At this time, the Companies' position mirrors the earlier conclusion that there is not a current need for coordination of maintenance schedules beyond that in place at ECAR.

LG&E owns a 75% undivided interest in Trimble County Unit 1. Of the remaining 25% of the unit, Illinois Municipal Electric Agency ("IMEA") purchased a 12.12% undivided interest in the unit on February 28, 1991 and Indiana Municipal Power Agency ("IMPA") purchased a 12.88% undivided interest on February 1, 1993. Each of these companies, IMEA and IMPA, had Right of First Refusal on ownership for Trimble County Unit 2. Both opted to retain their percentages for Trimble County Unit 2. The Companies have joint ownership with IMPA and IMEA, for Trimble County Unit 2 as contained in the plan. The Companies own 75% of the unit (60.75% KU and 14.25% LG&E) with IMPA and IMEA owning the remaining 25% (12.88% and 12.12%, respectively).

Table 8.(2)(c)
Generating Technology Option Summary
2004 $

Unit Type	Fuel Type	Size MW	Cost $/KW	F O&M ($/KW)	V O&M ($/MWH)	Heat Rate (Btu/KWH)	Comm Avail.	Tech. Rating
Combustion Turbine								
Simple Cycle GE LM6000 CT - 31 MW	Gas	31	[redacted]	$54	$3	10,329	Yes	Mature
Simple Cycle GE 7EA CT - 73 MW	Gas	73	[redacted]	$40	$7	12,420	Yes	Mature
Simple Cycle GE 7FA CT - 148 MW	Gas	148	[redacted]	$33	$13	11,132	Yes	Mature
Combined Cycle GE 7EA CT - 119 MW	Gas	119	[redacted]	$40	$4	7,772	Yes	Mature
Combined Cycle GE 7FA CT - 235 MW	Gas	235	[redacted]	$35	$4	7,032	Yes	Mature
Combined Cycle 2x1 GE 7FA CT - 484 MW	Gas	484	[redacted]	$32	$4	6,974	Yes	Mature
W 501F CC CT - 258 MW	Gas	258	[redacted]	$33	$4	7,337	Yes	Mature
Humid Air Turbine Cycle CT - 450 MW	Gas	450	[redacted]	$28	$3	6,500	No	Development
Kalina Cycle CC CT - 275 MW	Gas	275	[redacted]	$28	$3	6,700	No	Development
Cheng Cycle CT - 140 MW	Gas	140	[redacted]	$30	$3	8,500	No	Development
Peaking Microturbine - 0.03 MW	Gas	0.0	[redacted]	$0	$15	12,700	Yes	Commercial
Baseload Microturbine - 0.03 MW	Gas	0.0	[redacted]	$0	$15	12,000	Yes	Commercial
Pulverized Coal								
Supercritical Pulverized Coal - 500 MW	Coal	500	[redacted]	$22	$3	9,590	Yes	Mature
Supercritical Pulverized Coal, High Sulfur - 500 MW	Coal	500	[redacted]	$24	$4	9,398	Yes	Mature
Supercritical Pulverized Coal - 750 MW	Coal	750	[redacted]	$19	$3	9,383	Yes	Mature
Subcritical Pulverized Coal - 250 MW	Coal	250	[redacted]	$30	$3	9,976	Yes	Mature
Subcritical Pulverized Coal - 500 MW	Coal	500	[redacted]	$23	$2	9,756	Yes	Mature
Subcritical Pulverized Coal, High Sulfur - 500 MW	Coal	500	[redacted]	$24	$4	9,560	Yes	Mature
Supercritical Pulverized Coal, High Sulfur - 750 MW	Coal	750	[redacted]	$21	$4	9,195	Yes	Mature
Circulating Fluidized Bed - 250 MW	Coal	250	[redacted]	$33	$3	10,034	Yes	Mature
Circulating Fluidized Bed - 500 MW	Coal	500	[redacted]	$22	$3	9,812	Yes	Mature
TC2 732 MW Supercritical Pulverized Coal	Coal	732	[redacted]	$10	$1	8,900	Yes	Mature
Pressurized Fluid. Bed Combust. Coal								
Pressurized Fluidized Bed Combustion - 250 MW	Gas	250	[redacted]	$29	$5	8,500	No	Development
Integrated Gasification Combined Cycle								
IGCC - 267 MW	Coal Gasification	267	[redacted]	$47	$6	8,500	Yes	Mature
IGCC - 534 MW	Coal Gasification	534	[redacted]	$32	$6	8,500	Yes	Mature
Energy Storage								
Pumped Hydro Energy Storage - 500 MW	Charging Only	500	[redacted]	$9	$4	0	Yes	Commercial
Lead-Acid Battery Energy Storage - 5 MW	Charging Only	5	[redacted]	$14	$80	0	Yes	Commercial
Compressed Air Energy Storage - 500 MW	Gas and Charging	500	[redacted]	$16	$6	4,175	Yes	Commercial
Renewable Energy								
Wind Energy Conversion - 50 MW	No Fuel	50	[redacted]	$30	$0	0	Yes	N/A
Geothermal - 30 MW	Renew	30	[redacted]	$250	$0	0	Yes	Commercial
Solar Photovoltaic								
Solar Photovoltaic - 50 kW	No Fuel	0.1	[redacted]	$20	$23	0	Yes	Commercial
Solar Thermal								
Solar Thermal, Parabolic Trough - 100 MW	No Fuel	100	[redacted]	$0	$28	0	Yes	N/A
Solar Thermal, Parabolic Dish - 1.2 MW	No Fuel	1	[redacted]	$0	$15	0	Yes	N/A
Solar Thermal, Central Receiver - 50 MW	No Fuel	50	[redacted]	$0	$15	0	No	N/A
Solar Thermal, Solar Chimney - 200 MW	No Fuel	200	[redacted]	$0	$15	0	No	N/A
Waste Energy								
MSW Mass Burn - 7 MW	MSW	7	[redacted]	$300	$75	17,500	Yes	Commercial
RDF Stoker-Fired - 7 MW	RDF	7	[redacted]	$500	$80	19,300	Yes	Commercial
Landfill Gas IC Engine - 5 MW	Landfill Gas	5	[redacted]	$0	$15	9,500	Yes	Commercial
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	Tires	50	[redacted]	$58	$5	12,700	Yes	Early Commercial
Sewage Sludge & Anaerobic Digestion - .085 MW	No Fuel	0	[redacted]	$0	$15	0	No	Development
Bio Mass								
Biomass (Co-Fire) - 27.5MW	Renew	28	[redacted]	$60	$8	14,500	Yes	Commercial
Hydroelectric Power								
Hydroelectric - New - 30 MW	No Fuel	30	[redacted]	$15	$4	0	Yes	Mature
WV Hydro	No Fuel	181	[redacted]	[redacted]	[redacted]	[redacted]	Yes	Mature
Ohio Falls 9 and 10	No Fuel	34	[redacted]	$10	$0	0	Yes	Mature
Other								
Spark Ignition Engine - 5 MW	Gas	5	[redacted]	$0	$25	9,700	Yes	Commercial
Compression Ignition Engine - 10 MW	Gas	10	[redacted]	$0	$25	7,800	Yes	Commercial
Fuel Cell - 0.2 MW	Gas	0	[redacted]	$600	$8	8,250	Yes	Commercial

8.(2)(d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.

A Siting Board has been established to oversee proposed generation and transmission that formerly had not been subject to the jurisdiction of the Kentucky Public Service Commission. An example of how the Siting Board rulings have affected the Companies is in the 1,500 MW plant proposed by Thoroughbred Generating Company near Central City, KY. In December 2003, the Board granted a conditional permit to ensure that Kentucky ratepayers pay no share of the costs necessary for Thoroughbred to transmit electricity. In order to sell their unregulated power, lines owned by KU or Big Rivers would have to be upgraded.

Such impact on nonutility generators has contributed to fewer investors of new generation. This lack of viable investors in speculative development of new generation has diminished competition in new generation and thus influences future wholesale market price trends for power. Further details of the wholesale power market have been covered under that subsection of Section 6 of this IRP.

Nevertheless, the Companies continue to rely on Request for Proposal ("RFP") responses for purchased power in the future to ascertain the availability of long-term supply from non-utility generation, just as in the RFP process that the Companies completed in December 2004 as part of the CCN filing for Trimble County Unit 2 (Case No. 2004-00507). This RFP was for the purpose of evaluating options of the Companies purchasing power versus having ownership in units from other utilities. The RFP was necessary to meet the baseload capacity need in year 2008 identified in the Companies' 2002 IRP. The Companies also continue to use their participation in the wholesale market as a primary means of collecting data on purchased power availability and price for limited term supply of several years. A further discussion of this RFP process is detailed in the Resource Optimization portion of Section 8.(5)(c).

The Companies do receive inquiries from Independent Power Producers ("IPP"). The IPPs typically have an interest in projects based on combined-cycle or baseload technology. The Companies have evaluated and will continue to evaluate all bid proposals received with the goal of determining least-cost generation resources. Each proposal received will be evaluated on a case-by-case basis and if appropriate will be incorporated into the Companies' list of supply-side options for future evaluations. As discussed in the supply-side screening analysis included in the report titled *Analysis of Supply-Side Technology Alternatives* (November 2004) contained in Volume III, Technical Appendix, the Companies received a proposal from WV Hydro for a PPA. This WV Hydro project involves building three new hydro units on the Ohio River, known as Smithland, Cannelton, and Meldahl. These three plants were originally planned as merchant projects. WV Hydro will own the facilities and the Companies will purchase power from WV Hydro.

The Companies continue to evaluate purchases through the RFP process.

8.(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.

8.(3)(a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.

A map of the Companies' existing transmission system and generating facilities is included as Exhibit 8.(3)(a). The type of generating plants is indicated in the upper left-hand legend. The voltage rating of the various transmission lines and the symbol for interconnection points are indicated in the lower legend. All free-flowing interconnections with other utilities are listed in Table 8.(3)(a).

North-to-south transfers impact the flows on the Companies' system. The ability to dispatch generation economically within the Companies' control area may be limited under these conditions.

GENERATION STATIONS

1.	E.W. BROWN.......	697	STEAM
2.	BROWN CT........	947	COMBUSTION TURBINE
3.	DIX DAM..........	24	HYDRO
4.	GHENT............	1945	STEAM
5.	GREEN RIVER......	163	STEAM
6.	HAEFLING.........	36	COMBUSTION TURBINE
7.	LOCK SEVEN.......	0	RUN OF RIVER
8.	TYRONE...........	129	STEAM
9.	TRIMBLE CO.....	383	STEAM
10.	TRIMBLE CT....	960	COMBUSTION TURBINE
11.	MILL CREEK....	1472	STEAM
12.	CANE RUN.......	563	STEAM
	CANE RUN CT....	14	COMBUSTION TURBINE
13.	PADDYS RUN......	193	COMBUSTION TURBINE
14.	OHIO FALLS......	48	HYDRO
15.	WATERSIDE.......	22	COMBUSTION TURBINE
16.	ZORN............	14	COMBUSTION TURBINE

N

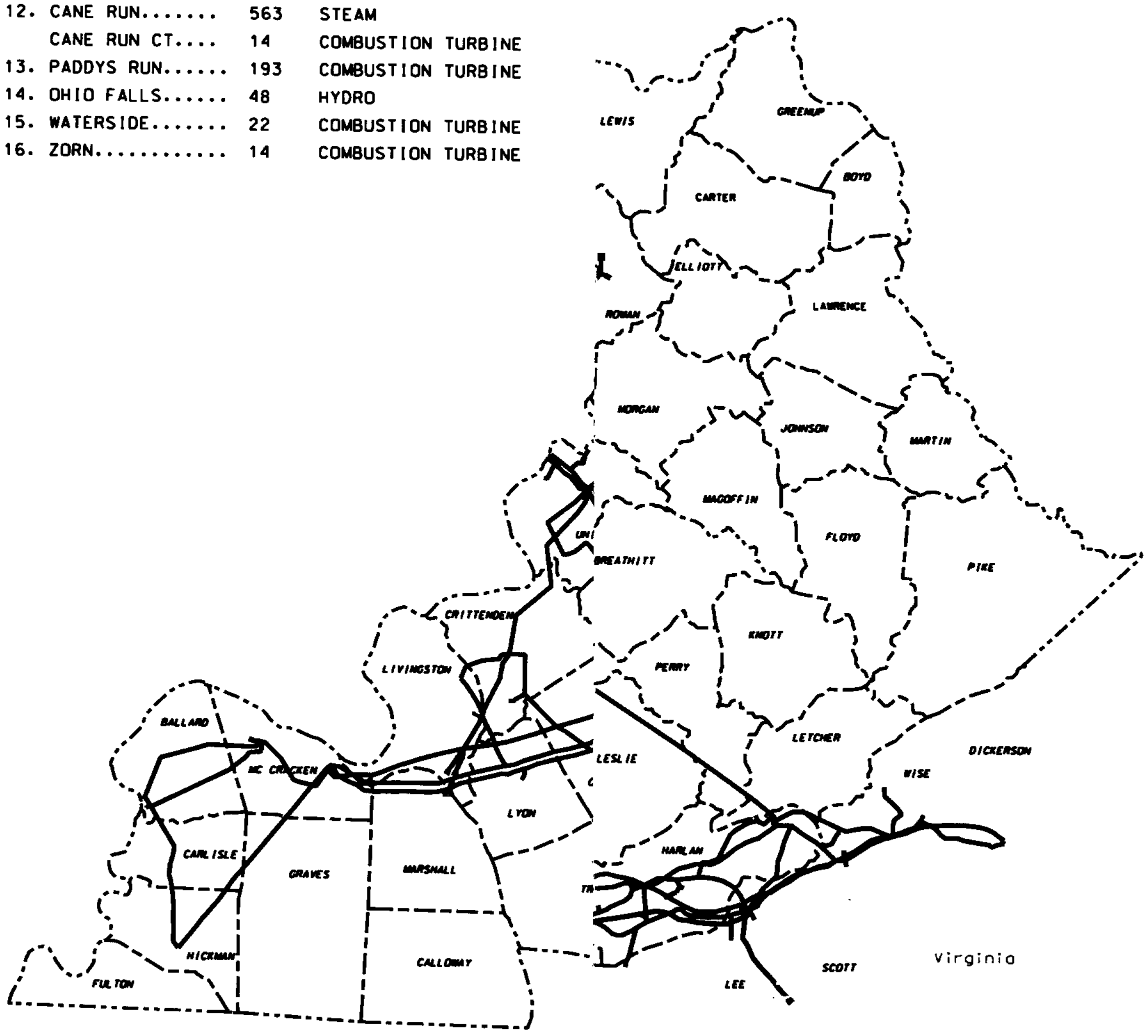

Table 8.(3)(a)
LG&E Energy LLC
Interconnections with Other Companies
September 10, 2004

Interconnection	KV	Limiting Company	Rating (MVA) Summer Normal	Summer Emergency	Winter Normal	Winter Emergency	By Letter Dated
AEP							
Kenton to Hillsboro	138	KU	164	191	191	191	9/20/93
Rodburn to Morehead	69	KU	33	38	33	43	3/27/96
			197	229	224	234	
BRECC							
Green River to Wilson	161	KU	529	558	558	558	5/24/00
Cloverport to Hardinsburg*	138	BREC	191	191	191	191	8/4/04
Hardinsburg to Hardinsburg*	138	BREC	191	191	191	191	8/4/04
*The net flow on these two interconnections is limited to 224/224 MVA.			911	940	940	940	
CINERGY							
Ghent to Batesville	345	KU & CIN	598	790	598	896	8/14/00
Ghent to Speed	345	KU	598	896	598	896	8/14/00
Beargrass/Northside to Jeffersonville	138	CIN	300	300	300	300	11/21/00
Ghent to Fairview	138	KU & CIN	227	382	304	382	4/23/87
Northside to Speed	138	CIN	287	287	287	287	8/14/00
Paddys West to Gallagher	138	CIN	382	382	382	382	8/14/00
			2392	3037	2469	3143	
DOE							
Grahamville to C-33A	161	KU & DOE	307	335	335	335	11/16/87
			307	335	335	335	
EKPC							
Blue Lick to Bullitt County	161	LG&E	235	235	279	313	6/6/02
Delvinta to Beattyville/Powell County	161	KU	167	167	167	167	8/21/00
Delvinta to Green Hall	161	KU	167	184	167	201	8/21/00
Elihu to Cooper	161	KU	239	289	279	305	6/6/02
Lebanon to Marion County	161/138	EKPC	135	167	167	167	2/26/87
Beattyville to Delvinta/Powell County	161/69	KU	56	64	67	72	6/6/02
Pittsburg to Laurel County/Tyner	161/69	KU	112	120	120	120	6/6/02
Taylor County to Green County/Marion County	161/69	KU	56	64	67	72	6/6/02
Fawkes to Fawkes	138	KU& EKPC	259	287	287	287	6/6/02
Fawkes/Lake Reba to Fawkes	138	EKPC	251	287	287	287	6/6/02
Ghent to Gallatin County	138	KU& EKPC	227	280	287	287	3/06/90
Goddard to Goddard/Plumville	138	KU	143	215	143	215	6/6/02
Kenton (91-744) to Spurlock	138	KU& EKPC	227	280	287	287	6/6/02

Table 8.(3)(a) – Continued
LG&E Energy LLC
Interconnections with Other Companies
September 10, 2004

Interconnection	KV	Limiting Company	Rating (MVA) Summer Normal	Summer Emergency	Winter Normal	Winter Emergency	By Letter Dated
Kenton (91-754) to Spurlock	138	KU& EKPC	227	280	287	287	6/6/02
Lake Reba Tap to Union City	138	KU	239	303	239	371	6/6/02
Loudon Avenue to Avon	138	KU& EKPC	224	277	287	287	6/6/02
Rodburn to Rowan County	138	KU	143	191	143	191	8/21/00
Bardstown/Etown to Nelson County	138/69	EKPC	143	143	143	143	2/26/87
Bonnieville to Bonnieville	138/69	EKPC	44	59	55	68	5/12/92
Boonesboro North to Avon/Dale	138/69	KU	93	107	96	117	6/6/02
Brown North/Higby Mill to Baker Lane	138/69	EKPC	96	129	119	143	6/6/02
Ghent/Scott County to Owen County	138/69	EKPC	143	143	143	143	2/26/87
Scott County to Penn	69	KU& EKPC	31	35	43	46	6/6/02
Beattyville to Beattyville	69	EKPC	72	79	72	86	6/6/02
Bardstown Industrial to East Bardstown	69	EKPC	54	54	54	54	8/21/00
Bonds Mill to Mill Junction	69	KU& EKPC	72	72	72	72	6/6/02
Bromley to Owen County	69	KU	56	56	72	86	6/6/02
Carntown to Bracken County	69	KU	41	41	66	66	6/6/02
Carrollton to Hunters Bottom	69	KU& EKPC	45	54	60	68	6/6/02
Clay Village to Clay Village	69	EKPC	36	36	36	36	10/17/89
Cynthiana Switching to Renaker	69	KU& EKPC	57	57	72	72	3/07/96
Eastview to Stephensburg	69	KU& EKPC	41	41	54	54	6/6/02
Elizabethtown to Kargle	69	KU& EKPC	57	69	72	86	5/12/92
Elizabethtown to Tharp	69	KU& EKPC	72	86	72	93	8/18/04
Farley to South Corbin	69	KU& EKPC	53	53	72	72	2/26/87
Fawkes to Crooksville	69	KU& EKPC	72	79	72	86	6/6/02
Ferguson South to Somerset*	69	KU& EKPC	82	82	101	101	6/6/02
Finchville/Shelbyville to Shelby County	69	EKPC	72	72	72	72	8/24/00
Greensburg to Green County	69	EKPC	54	54	54	54	3/31/92
Hodgenville to Hodgenville	69	KU	39	39	78	78	6/6/02
Hopewell to Laurel County	69	KU& EKPC	72	89	96	96	6/6/02
Kenton to Murphysville	69	KU& EKPC	72	72	72	72	10/05/87
New Haven to Hodgenville	69	KU	44	44	72	80	6/6/02
Rogersville to Vine Grove	69	EKPC	72	79	72	86	6/6/02
Sardis to Murphysville	69	KU	41	50	55	61	6/6/02
Sharon to Bracken County	69	KU	27	27	48	57	6/6/02
Somerset South to Somerset*	69	KU	56	56	75	75	6/6/02
Springfield to North Springfield	69	KU& EKPC	31	31	36	36	6/6/02
Union Underwear to Sewellton	69	KU	41	41	66	66	6/6/02
*The net flow on these two interconnections is limited to 96 MVA.			5088	5819	5902	6441	
OMU							
Hardin County to Smith	345	OMU	308	308	308	320	2/5/04
Green River Steel to Smith	138	KU & OMU	241	241	287	287	10/05/87
Green River Steel to Smith	69	KU	72	86	72	100	10/05/87
			621	635	667	707	

Table 8.(3)(a) – Continued
LG&E Energy LLC
Interconnections with Other Companies
September 10, 2004

Interconnection	KV	Limiting Company	Rating (MVA)				By Letter Dated
			Summer		Winter		
			Normal	Emergency	Normal	Emergency	
OVEC							
Trimble County to Clifty Creek	345	LG&E & OVEC	1147	1195	1147	1195	7/25/01
Carrollton to Clifty Creek	138	KU&OVEC	181	210	191	210	7/25/01
Northside to Clifty Creek	138	LG&E	113	113	162	162	5/16/01
			1441	1518	1500	1567	
SIGE							
Cloverport to Newtonville	138	LG&E	239	275	287	287	6/16/04
			239	275	287	287	
TVA							
Pocket North to Phipps Bend	500	KU	693	693	693	693	2/11/87
Livingston County to Calvert City	161	TVA	223	223	263	263	2/22/93
Livingston County to Kentucky Dam	161	KU & TVA	290	298	335	335	2/22/93
Paddys Run to Summershade	161	LG&E & TVA	223	239	223	263	11/21/00
Pineville Switching to Pineville	161	KU	239	242	319	335	11/8/00
Paducah South to Kentucky Dam	69	KU & TVA	27	27	36	42	11/21/00
Paducah South/Princeton to Kentucky Dam	69	KU & TVA	54	54	72	72	3/27/96
			1749	1776	1941	2003	

8.(3)(b) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility:

1. **Plant name;**
2. **Unit number(s);**
3. **Existing or proposed location;**
4. **Status (existing, planned, under construction, etc.);**
5. **Actual or projected commercial operation date;**
6. **Type of facility;**
7. **Net dependable capability, summer and winter;**
8. **Entitlement if jointly owned or unit purchase;**
9. **Primary and secondary fuel types, by unit;**
10. **Fuel storage capacity;**
11. **Scheduled upgrades, deratings, and retirement dates;**
12. **Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars.**
    a. **Capacity and availability factors;**
    b. **Anticipated annual average heat rate;**
    c. **Costs of fuel(s) per millions of British thermal units (MMBtu);**
    d. **Estimate of capital costs for planned units (total and per kilowatt of rated capacity);**
    e. **Variable and fixed operating and maintenance costs;**
    f. **Capital and operating and maintenance cost escalation factors;**
    g. **Projected average variable and total electricity production costs (in cents per kilowatt-hour).**

The requested information can be found in the tables on the following pages.

Table 8.(3)(b)

Kentucky Utilities Company / Louisville Gas & Electric Company

Existing and Planned Electric Generating Facilities

1	2	3	4	5	6	7		8		9	10	11
Plant Name	Unit No.	Location in Kentucky	Status	Operation Date	Facility Type	Net Capability (MW) Winter	Summer	Entitlement KU	LGE	Fuel Type	Fuel Storage Cap/SO2 Content	Scheduled Upgrades Derates, Retirements
Cane Run	4	Louisville	Existing	1962	Steam	155	155		100%	Coal (Rail)	250,000 Tons (6.0# SO2)	None
	5			1966		168	168					
	6			1969		240	240					
	11			1968	Turbine	14	14			Gas/Oil	100,000 Gals	
Dix Dam	1-3	Burgin	Existing	1925	Hydro	24	24	100%		Water	None	None
E. W. Brown Coal	1	Burgin	Existing	1957	Steam	102	101	100%		Coal (Rail)	360,000 Tons (~2.2# SO2)	FGD Derate - 2009
	2			1963		169	167					
	3			1971		433	429					
E.W. Brown-ABB 11N2	5			2001	Turbine	143	135	47%	53%	Gas	2,200,000 Gals	None
E.W. Brown-ABB GT24	6			1999		168	154	62%	38%	Gas/Oil		None
	7			1999		168	154					
E.W. Brown-ABB 11N2	8			1995		140	126	100%				None
	9			1994		140	126					
	10			1995		140	126					
	11			1996		140	126					
Ghent	1	Ghent	Existing	1974	Steam	468	475	100%		Coal (Barge)	310,000 Tons (6# SO2)	None
	2			1977		466	484				1,000,000 Tons (1.1# SO2 & PRB)	FGD Derate - 2008
	3			1981		495	493					FGD Derate - 2007
	4			1984		495	493					FGD Derate - 2009
Green River	3	Central City	Existing	1954	Steam	71	68	100%		Coal	170,000 Tons	None
	4			1959		102	95					
Haefling	1	Lexington	Existing	1970	Turbine	14	12	100%		Gas/Oil	630,000 Gals	None
	2			1970		14	12					
	3			1970		14	12					
Lock 7	1-3	Burgin	Existing	1927	Hydro	Run of River Plant		Lease		Water	None	None
Mill Creek	1	Louisville	Existing	1972	Steam	303	303		100%	Coal (Barge & Rail)	750,000 Tons	None
	2			1974		299	301					
	3			1978		397	391					
	4			1982		492	477					
Ohio Falls	1-8	Louisville	Existing	1928	Hydro	Run of River Plant (32/48)			100%	Water	None	Rehab begins Fall 2005
Paddy's Run	11	Louisville	Existing	1968	Turbine	13	12		100%	Gas	None	None
	12			1968		28	23					
Paddys Run-Siem/West V84.3a	13			2001		175	158	47%	53%		Unknown at this time	
Tyrone	1	Versailles	Existing	1947	Steam	30	27	100%		Oil (Truck)	514,000 Gals	None
	2			1948		33	31					
	3			1953		73	71			Coal (Trk)	30,000 Tons (1.4# SO2)	
Trimble County Coal (75%)	1	Near Bedford	Existing	1990	Steam	514 (386)	511 (383)	0%	75%	Coal (Barge)	500,000 Tons (6.0# SO2)	None
Trimble County-GE7FA	5			2002	Turbine	180	160	71%	29%	Gas		
	6			2002		180	160					
	7			2004		180	160	63%	37%			
	8			2004		180	160					
	9			2004		180	160					
	10			2004		180	160					
Waterside	7	Louisville	Existing	1964	Turbine	13	11		100%	Gas	None	None
	8			1964		13	11					
Zorn	1	Louisville	Existing	1969	Turbine	16	14		100%	Gas	None	None
Future Units												
Trimble County Coal (75%)	2	Near Bedford	Proposed	2010	Steam	750 (563)	732 (549)	61%	14%	Coal	Unknown at this time	None
Greenfield CT	1	Unknown	Planned	2013	Turbine	181	148	Unknown		Gas	None	None
	2			2015		181	148					
	3			2015		181	148					
	4			2016		181	148					
	5			2017		181	148					
	6			2018		181	148					
W.V. Hydro (PPA)		Smithland/Cannelton	Proposed	2014	Hydro	99	181	Unknown		Water	None	None
Greenfield Coal Unit	1	Unknown	Proposed	2019	Steam	750	750	Unknown		Coal	Unknown at this time	None

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	64.1	56.1	50.5	57.1	58.0	62.3	60.6	60.4	60.7	54.8	61.3	61.7	61.8	62.8	63.0	62.7
	Availability Factor (%)	90.1	90.6	81.4	90.6	90.6	94.3	90.6	90.6	90.6	81.4	90.6	90.6	90.6	90.6	90.6	90.6
b	**Average Heat Rate (Btu/kWh)**	11,034	10,842	10,844	10,850	10,858	10,858	10,845	10,843	10,846	10,849	10,850	10,853	10,854	10,862	10,862	10,860
c	**Cost of Fuel ($/MBTU)**	1.60	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 2

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	66.2	62.7	64.2	66.2	54.8	72.8	74.3	72.0	72.8	68.5	64.1	56.0	62.5	68.1	69.0	69.7
	Availability Factor (%)	90.3	90.4	90.4	90.4	81.2	88.6	90.5	90.5	90.5	90.5	90.5	81.2	90.5	90.5	90.5	90.5
b	**Average Heat Rate (Btu/kWh)**	10,259	10,113	10,084	10,038	10,162	9,933	9,933	9,978	9,963	10,049	10,155	10,198	10,195	10,060	10,041	10,024
c	**Cost of Fuel ($/MBTU)**	1.59	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 3

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	59.6	39.5	44.3	45.8	46.7	51.0	47.3	46.7	42.2	48.4	48.2	49.2	49.4	51.3	51.4	44.0
	Availability Factor (%)	85.9	80.7	89.9	89.9	88.0	89.9	89.9	89.9	80.7	89.9	89.9	89.9	89.9	89.9	89.9	80.7
b	**Average Heat Rate (Btu/kWh)**	10,534	10,670	10,666	10,649	10,628	10,606	10,644	10,651	10,647	10,631	10,634	10,623	10,621	10,602	10,602	10,625
c	**Cost of Fuel ($/MBTU)**	1.62	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 5

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	0.0	0.4	0.3	0.2	0.3	0.6	0.1	0.2	0.4	0.5	0.5	0.8	2.4	4.0	4.3	1.1
	Availability Factor (%)	99.0	86.8	86.8	86.8	86.8	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	Average Heat Rate (Btu/kWh)	0	12,618	12,619	12,666	12,629	12,570	12,663	12,612	12,576	12,548	12,550	12,509	13,812	14,008	13,828	12,501
c	Cost of Fuel ($/MBTU)	6.82	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 6

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	0.8	1.1	1.0	0.7	1.0	3.1	0.4	0.6	0.9	2.9	2.9	4.8	6.8	7.2	9.1	6.8
	Availability Factor (%)	79.7	76.4	86.8	86.8	79.9	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	Average Heat Rate (Btu/kWh)	15,050	10,462	10,462	10,466	10,461	10,566	10,468	10,462	10,458	10,576	10,577	10,595	10,602	10,588	10,594	10,585
c	Cost of Fuel ($/MBTU)	7.02	[redacted]														

Notes: 2004 numbers are actuals. Unit ran on oil only in 2001.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 7

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	1.5	0.7	0.6	0.4	0.6	0.9	0.2	0.3	0.6	0.8	0.8	2.8	3.2	6.8	7.0	3.0
	Availability Factor (%)	94.7	76.4	86.8	79.9	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	Average Heat Rate (Btu/kWh)	12,830	10,467	10,467	10,472	10,467	10,461	10,471	10,466	10,462	10,459	10,460	10,579	10,563	10,601	10,590	10,542
c	Cost of Fuel ($/MBTU)	6.90	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 8

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	0.0	0.2	0.2	0.1	0.2	0.4	0.1	0.1	0.2	0.3	0.3	0.6	0.8	2.6	4.3	0.8
	Availability Factor (%)	83.1	90.3	90.3	85.1	90.3	76.4	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	Average Heat Rate (Btu/kWh)	0	12,580	12,578	12,603	12,583	12,557	12,606	12,574	12,552	12,541	12,548	12,524	12,509	13,176	13,278	12,483
c	Cost of Fuel ($/MBTU)	6.09	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 9

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	0.0	0.1	0.1	0.1	0.1	0.2	0.0	0.1	0.1	0.2	0.2	0.4	0.6	0.9	2.7	0.5
	Availability Factor (%)	99.9	86.8	90.3	85.1	90.3	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	Average Heat Rate (Btu/kWh)	0	12,602	12,586	12,597	12,602	12,574	12,611	12,583	12,573	12,559	12,561	12,537	12,520	12,506	13,145	12,497
c	Cost of Fuel ($/MBTU)	6.93	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 10

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.1	0.1	0.1	0.0	0.1	0.1	0.0	0.0	0.1	0.1	0.1	0.2	0.4	0.6	1.0	0.3
	Availability Factor (%)	99.0	90.3	85.1	86.8	90.3	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	**Average Heat Rate (Btu/kWh)**	19,995	12,616	12,606	12,617	12,596	12,590	12,604	12,589	12,590	12,569	12,576	12,553	12,535	12,517	12,499	12,513
c	**Cost of Fuel ($/MBTU)**	6.15	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

E.W. Brown 11

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.1	0.0	0.0	0.0	0.0	0.1	0.0	0.0	0.0	0.1	0.1	0.2	0.3	0.4	0.7	0.2
	Availability Factor (%)	99.1	92.0	84.9	88.5	88.5	92.0	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5	88.5
b	**Average Heat Rate (Btu/kWh)**	43,580	12,626	12,581	12,605	12,635	12,597	12,575	12,587	12,608	12,589	12,599	12,564	12,551	12,530	12,508	12,530
c	**Cost of Fuel ($/MBTU)**	5.95	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Cane Run 4

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	59.8	67.6	69.6	67.8	62.6	56.8	53.4	47.8	53.8	55.2	55.5	55.9	56.1	61.1	55.6	63.2
	Availability Factor (%)	77.0	87.9	88.2	88.2	88.2	88.2	88.2	79.2	88.2	88.2	88.2	88.2	88.2	88.2	79.2	88.2
b	**Average Heat Rate (Btu/kWh)**	11,092	11,145	11,092	11,146	11,325	11,553	11,715	11,720	11,698	11,631	11,614	11,595	11,588	11,377	11,347	11,301
c	**Cost of Fuel ($/MBTU)**	1.22	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Cane Run 5

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	60.8	59.7	62.2	60.9	49.9	52.9	49.1	48.5	48.7	50.4	50.0	45.7	51.4	53.7	53.5	51.5
	Availability Factor (%)	76.0	87.3	87.6	87.6	78.6	87.6	87.6	87.6	87.6	87.6	87.6	78.6	87.6	87.6	87.6	87.6
b	**Average Heat Rate (Btu/kWh)**	10,853	10,975	10,953	10,965	11,024	11,057	11,110	11,120	11,117	11,091	11,098	11,084	11,078	11,046	11,048	11,076
c	**Cost of Fuel ($/MBTU)**	1.22	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Cane Run 6

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	71.8	65.4	68.0	71.8	70.2	60.4	60.3	58.4	59.6	62.6	61.2	63.9	57.5	70.2	71.4	70.8
	Availability Factor (%)	89.9	87.4	87.7	87.7	87.7	78.7	87.7	87.7	87.7	87.7	87.7	87.7	78.7	87.7	87.7	87.7
b	**Average Heat Rate (Btu/kWh)**	10,349	10,741	10,655	10,536	10,584	10,682	10,951	11,040	10,986	10,859	10,918	10,806	10,800	10,583	10,548	10,566
c	**Cost of Fuel ($/MBTU)**	1.18	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Cane Run 11

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	96.5	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	**Average Heat Rate (Btu/kWh)**	34,727	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	**Cost of Fuel ($/MBTU)**	7.25	[redacted]														

Notes: 2004 numbers are actuals.

Capacity Factor (%) based on net summer unit rating. Unit Runs less than 1% capacity factor.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ghent 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	79.2	72.0	78.7	70.8	71.9	71.0	63.7	60.2	62.3	64.2	57.9	67.2	67.0	69.9	70.0	63.6
	Availability Factor (%)	84.7	90.1	90.1	79.1	88.3	90.1	90.1	90.1	90.1	90.1	80.9	90.1	90.1	90.1	90.1	90.1
b	**Average Heat Rate (Btu/kWh)**	10,369	10,321	10,332	10,336	10,324	10,319	10,303	10,295	10,300	10,304	10,305	10,311	10,311	10,317	10,317	10,303
c	**Cost of Fuel ($/MBTU)**	1.17	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ghent 2

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	66.9	38.6	45.3	45.8	64.0	70.3	64.2	63.1	57.1	66.0	66.2	67.5	67.3	64.7	64.9	56.6
	Availability Factor (%)	92.8	80.0	89.1	89.1	81.9	87.3	89.1	89.1	80.0	89.1	89.1	89.1	89.1	89.1	89.1	80.0
b	Average Heat Rate (Btu/kWh)	10,021	10,164	10,159	10,160	10,141	10,139	10,144	10,145	10,144	10,143	10,143	10,142	10,142	10,144	10,144	10,145
c	Cost of Fuel ($/MBTU)	1.69	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ghent 3

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	65.3	47.7	48.9	66.0	66.5	62.2	50.1	52.4	53.9	55.4	55.4	56.4	56.9	51.8	59.6	56.7
	Availability Factor (%)	89.0	89.9	89.9	82.5	88.0	89.9	80.7	89.9	89.9	89.9	89.9	89.9	89.9	80.7	89.9	89.9
b	**Average Heat Rate (Btu/kWh)**	10,763	10,872	10,867	10,805	10,814	10,827	10,846	10,858	10,852	10,847	10,848	10,844	10,842	10,840	10,834	10,843
c	**Cost of Fuel ($/MBTU)**	1.70	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Ghent 4

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	71.3	52.8	53.9	50.9	50.1	60.0	62.2	57.8	59.7	60.7	62.2	64.9	58.7	65.3	66.4	62.0
	Availability Factor (%)	94.1	89.8	88.0	89.8	89.8	78.8	89.8	89.8	89.8	89.8	89.8	89.8	80.7	89.8	89.8	89.8
b	**Average Heat Rate (Btu/kWh)**	10,875	10,810	10,799	10,822	10,827	10,745	10,769	10,790	10,780	10,776	10,769	10,758	10,756	10,756	10,752	10,770
c	**Cost of Fuel ($/MBTU)**	1.69	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Green River 3

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	56.1	48.0	47.9	48.6	49.3	45.2	48.1	48.1	48.5	49.5	49.1	49.8	45.0	51.6	51.7	50.6
	Availability Factor (%)	88.3	88.1	87.6	87.6	87.6	78.7	87.6	87.6	87.6	87.6	87.6	87.6	78.7	87.6	87.6	87.6
b	Average Heat Rate (Btu/kWh)	13,032	13,227	13,226	13,219	13,213	13,203	13,223	13,224	13,220	13,211	13,214	13,208	13,206	13,194	13,193	13,201
c	Cost of Fuel ($/MBTU)	1.39	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Green River 4

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	55.8	49.5	50.6	50.6	51.5	52.9	45.5	50.1	50.6	51.3	51.3	52.1	52.1	47.6	53.9	53.6
	Availability Factor (%)	80.8	87.9	87.5	87.5	87.5	87.5	78.5	87.5	87.5	87.5	87.5	87.5	87.5	78.5	87.5	87.5
b	Average Heat Rate (Btu/kWh)	11,880	12,382	12,336	12,335	12,306	12,263	12,334	12,353	12,336	12,314	12,312	12,287	12,288	12,261	12,232	12,239
c	Cost of Fuel ($/MBTU)	1.39	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating. Unit Runs less than 1% capacity factor.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Haefling 1,2,3

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.1	6.5	7.0	8.2	9.5	9.2	13.7	13.4	13.6	13.8	12.1	12.4	11.4	12.5	12.3	12.2
	Availability Factor (%)	100.0	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8	33.8
b	**Average Heat Rate (Btu/kWh)**	0	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021	17,021
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating. Unit Runs less than 1% capacity factor.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Mill Creek 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	69.4	80.7	76.3	79.3	74.5	78.5	70.8	79.4	69.6	81.6	69.9	76.8	72.2	84.2	79.7	81.8
	Availability Factor (%)	84.5	91.3	88.1	91.7	86.3	91.7	86.3	91.7	79.1	91.7	86.3	91.7	86.3	91.7	86.3	91.7
b	Average Heat Rate (Btu/kWh)	10,471	10,546	10,569	10,571	10,571	10,582	10,633	10,567	10,550	10,536	10,649	10,607	10,609	10,502	10,496	10,535
c	Cost of Fuel ($/MBTU)	1.21	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Mill Creek 2

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	76.4	78.2	83.1	78.2	84.3	82.1	85.3	73.0	85.3	81.4	85.5	81.0	86.9	81.9	88.2	72.9
	Availability Factor (%)	92.5	86.0	91.8	86.4	91.8	86.4	91.8	79.2	91.8	86.4	91.8	86.4	91.8	86.4	91.8	79.2
b	**Average Heat Rate (Btu/kWh)**	10,586	11,002	11,013	11,011	10,983	10,915	10,958	10,974	10,961	10,932	10,953	10,941	10,922	10,920	10,893	10,977
c	**Cost of Fuel ($/MBTU)**	1.19	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Mill Creek 3

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	66.9	88.9	87.8	85.2	90.7	85.9	88.1	82.1	87.6	76.1	87.6	83.5	89.3	85.1	90.9	83.8
	Availability Factor (%)	73.0	89.9	90.3	86.7	92.1	86.7	92.1	86.7	92.1	79.5	92.1	86.7	92.1	86.7	92.1	86.7
b	**Average Heat Rate (Btu/kWh)**	10,515	10,487	10,513	10,496	10,491	10,484	10,538	10,552	10,545	10,534	10,545	10,527	10,515	10,497	10,488	10,520
c	**Cost of Fuel ($/MBTU)**	1.25	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Mill Creek 4

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	81.7	85.5	70.4	83.0	81.1	87.6	76.6	80.7	76.3	84.1	70.4	84.1	78.7	87.7	82.7	85.7
	Availability Factor (%)	90.4	91.5	79.3	92.2	86.8	92.2	86.8	92.2	86.8	92.2	79.5	92.2	86.8	92.2	86.8	92.2
b	**Average Heat Rate (Btu/kWh)**	10,523	10,606	10,642	10,632	10,606	10,595	10,645	10,653	10,649	10,623	10,644	10,623	10,627	10,593	10,592	10,610
c	**Cost of Fuel ($/MBTU)**	1.22	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Paddy's Run 11

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	99.9	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	Average Heat Rate (Btu/kWh)	0	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Paddy's Run 12

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	99.3	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	**Average Heat Rate (Btu/kWh)**	0	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Paddy's Run 13

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	2.3	11.6	9.9	12.0	12.2	13.1	11.8	10.5	11.9	12.4	13.3	11.9	14.8	18.0	13.3	15.5
	Availability Factor (%)	92.3	88.6	88.6	88.6	88.6	88.6	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	**Average Heat Rate (Btu/kWh)**	10,694	11,793	11,745	11,633	11,602	11,391	11,657	11,614	11,602	11,552	11,602	11,401	11,521	11,603	11,315	11,624
c	**Cost of Fuel ($/MBTU)**	6.61	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	92.2	76.8	87.4	79.6	87.6	72.5	86.1	77.8	86.1	78.3	85.2	78.3	85.5	69.9	85.6	75.9
	Availability Factor (%)	98.4	88.2	95.5	88.2	95.5	80.8	95.5	88.2	95.5	88.2	95.5	88.2	95.5	80.8	95.5	88.2
b	**Average Heat Rate (Btu/kWh)**	10,360	10,128	10,101	10,100	10,100	10,099	10,112	10,118	10,112	10,113	10,120	10,113	10,118	10,126	10,116	10,137
c	**Cost of Fuel ($/MBTU)**	1.16	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 5

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	1.5	8.0	8.9	13.5	19.0	22.6	15.0	10.0	13.9	17.2	19.9	21.6	24.1	26.2	23.9	24.6
	Availability Factor (%)	96.6	90.3	90.3	86.8	90.3	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	Average Heat Rate (Btu/kWh)	0	11,063	11,070	11,083	11,088	11,051	11,103	10,960	11,035	11,021	11,085	11,060	11,077	10,971	10,941	10,981
c	Cost of Fuel ($/MBTU)	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 6

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	1.6	6.4	8.2	9.1	11.4	16.1	11.8	9.0	10.7	13.3	14.5	17.6	19.6	23.9	21.2	20.4
	Availability Factor (%)	96.2	90.3	90.3	86.8	90.3	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	Average Heat Rate (Btu/kWh)	0	11,139	11,161	11,048	10,996	11,026	11,124	11,063	11,043	11,025	11,058	11,078	11,086	11,033	10,992	10,993
c	Cost of Fuel ($/MBTU)	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 7

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	2.2	3.0	4.5	8.4	9.1	11.4	6.8	6.8	9.9	10.9	11.0	12.7	16.4	19.9	16.3	19.3
	Availability Factor (%)	92.2	90.3	90.3	90.3	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	**Average Heat Rate (Btu/kWh)**	0	10,937	11,083	11,142	11,051	11,011	11,026	11,068	11,129	11,063	11,063	11,055	11,110	11,054	10,979	11,071
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals. Unit was run for an insignificant (<20 hours) amount of time.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 8

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	1.5	0.0	2.7	6.2	8.4	10.4	3.4	4.7	8.2	7.2	7.2	9.2	9.6	13.3	15.3	16.0
	Availability Factor (%)	91.3	100.0	90.3	90.3	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	**Average Heat Rate (Btu/kWh)**	0	0	10,991	11,175	11,149	11,110	10,852	11,049	11,158	11,005	11,008	11,044	10,985	10,984	11,061	11,088
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals. Unit was run for an insignificant (<20 hours) amount of time.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 9

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	1.8	0.0	0.0	2.8	4.5	6.8	1.2	2.8	4.7	6.5	6.6	8.4	8.8	12.3	12.5	14.5
	Availability Factor (%)	90.0	100.0	100.0	90.3	90.3	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	**Average Heat Rate (Btu/kWh)**	0	0	0	10,966	11,087	11,060	10,352	10,962	11,044	11,102	11,106	11,135	11,074	11,075	11,074	11,143
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County CT 10

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	0.9	0.0	0.0	0.9	2.7	4.5	0.7	0.9	2.8	4.6	4.6	6.4	8.3	9.0	9.0	8.6
	Availability Factor (%)	83.9	100.0	100.0	90.3	90.3	90.3	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8	86.8
b	Average Heat Rate (Btu/kWh)	0	0	0	10,363	10,995	11,080	10,375	10,349	10,954	11,080	11,088	11,133	11,150	11,065	11,028	11,036
c	Cost of Fuel ($/MBTU)	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Tyrone 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	100.0	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1	94.1
b	**Average Heat Rate (Btu/kWh)**	0	14,189	14,189	14,188	14,189	14,189	14,189	14,188	14,189	14,189	14,189	14,189	14,189	14,189	14,188	14,189
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals. Unit was not operated in 2001.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Tyrone 2

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	100.0	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5	95.5
b	**Average Heat Rate (Btu/kWh)**	0	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,189	14,188	14,189	14,189	14,189	14,189	14,189
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Tyrone 3

		2001	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016
a	**Capacity Factor (%)**	38.2	12.2	12.5	17.6	22.7	27.3	17.3	16.5	19.2	25.7	24.4	26.2	28.1	31.0	28.9	27.1
	Availability Factor (%)	74.8	89.0	88.5	88.5	88.5	88.5	79.5	88.5	88.5	88.5	88.5	88.5	88.5	79.5	88.5	88.5
b	**Average Heat Rate (Btu/kWh)**	13,384	12,990	12,986	12,980	12,979	12,962	12,976	12,968	12,966	12,989	12,979	12,975	12,974	12,953	12,943	12,956
c	**Cost of Fuel ($/MBTU)**	2.27	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Waterside 7

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	100.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	**Average Heat Rate (Btu/kWh)**	0	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Waterside 8

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	100.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	**Average Heat Rate (Btu/kWh)**	0	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000	17,000
c	**Cost of Fuel ($/MBTU)**	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Zorn 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)	98.7	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0	50.0
b	Average Heat Rate (Btu/kWh)	0	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000	18,000
c	Cost of Fuel ($/MBTU)	0.00	[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Trimble County 2 (75%)

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**							52.6	88.0	88.3	88.4	88.2	88.3	88.4	88.5	88.6	88.6
	Availability Factor (%)							87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6	87.6
b	**Average Heat Rate (Btu/kWh)**							8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865	8,865
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 2004 numbers are actuals.

Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Greenfield CT 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**										0.0	0.0	0.0	0.0	0.0	0.0	0.0
	Availability Factor (%)										91.3	91.3	91.3	91.3	91.3	91.3	91.3
b	**Average Heat Rate (Btu/kWh)**										12,375	12,358	12,263	12,316	12,372	12,349	12,084
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Greenfield CT 2

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**												0.0	0.0	0.0	0.1	0.0
	Availability Factor (%)												91.3	91.3	91.3	91.3	91.3
b	**Average Heat Rate (Btu/kWh)**												12,363	12,278	12,321	12,342	12,241
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

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Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Greenfield CT 3

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)												0.1	0.1	0.1	0.1	0.0
	Availability Factor (%)												91.3	91.3	91.3	91.3	91.3
b	Average Heat Rate (Btu/kWh)												12,306	12,311	12,301	12,260	12,297
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Greenfield CT 4

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)													0.2	0.2	0.2	0.0
	Availability Factor (%)													91.3	91.3	91.3	91.3
b	Average Heat Rate (Btu/kWh)													12,248	12,242	12,235	12,337
c	Cost of Fuel ($/MBTU)		[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.

Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Greenfield CT 5

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**														0.3	0.3	0.1
	Availability Factor (%)														91.3	91.3	91.3
b	**Average Heat Rate (Btu/kWh)**														12,197	12,182	12,254
c	**Cost of Fuel ($/MBTU)**		[redacted]														

Notes: 2004 numbers are actuals.
Capacity Factor (%) based on net summer unit rating.