LG&E KU

SUBSIDIARIES OF
LG&E ENERGY

2005–2019 Energy Requirements and Demand Forecast

April 2005

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ENERGY REQUIREMENTS AND DEMAND FORECAST, 2005–2019

Introduction

Kentucky Utilities Company (KU) provides electrical service to customers in seventy-seven counties throughout Kentucky, and to customers in five counties in Southwestern Virginia through its Old Dominion Power operating unit. In addition, the Company sells electricity to 11 municipally-owned utilities in Kentucky.

Louisville Gas and Electric Company (LG&E) provides electrical service to customers in Jefferson County and eight surrounding counties in Kentucky. Together, the Companies serve a diverse range of retail customers in the Residential, Commercial, Industrial, Coal Mining and Street Lighting sectors.

Forecasting future energy requirements and demand is a prerequisite for prudent planning and control of the Company's operations. The forecast becomes the basis for decisions regarding construction of facilities, such as power plants, transmission and distribution lines, and substations, all of which are vital to providing reliable service. The desired outcome of the forecasting process is a robust and reasonable estimate against which investment strategies and performance goals can be appraised on an objective basis so that the Company's mission of providing adequate and reliable electric service to its customers at the lowest reasonable cost can be attained. Different forecasting approaches are continuously evaluated to maintain the reliability of the process.

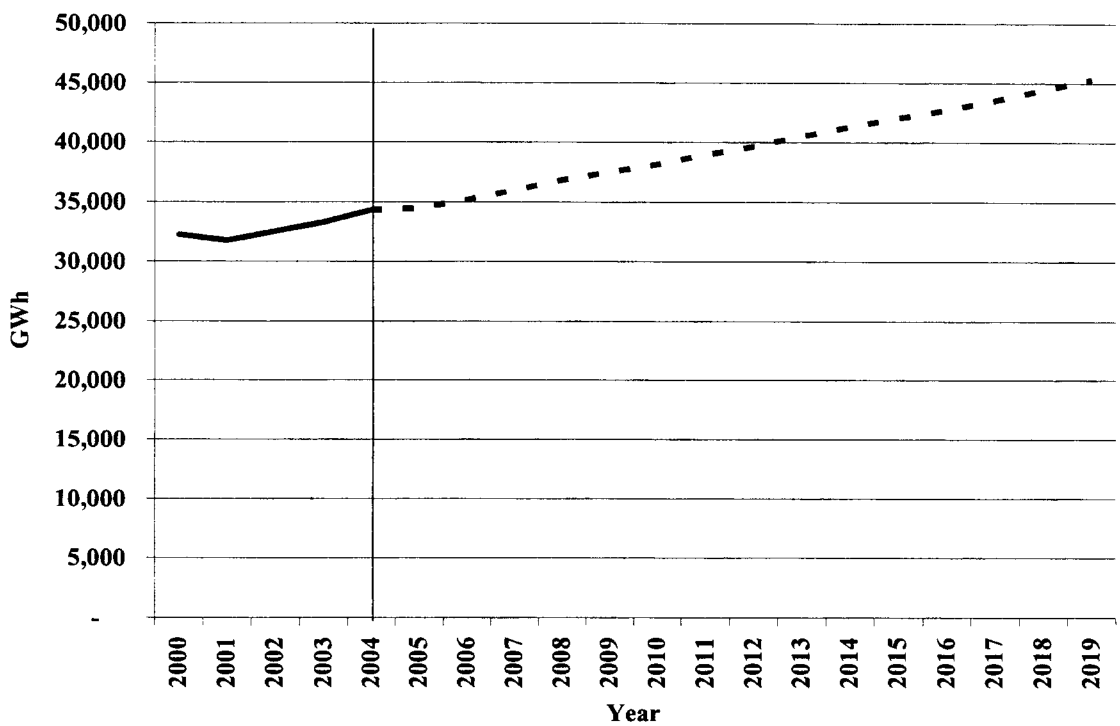
The 2005-2019 hourly demand forecasts for KU and LG&E were developed from the energy requirements forecasts and representative monthly load shapes for the two companies. The utility demand forecasts include the effects of the KU Curtailable Service Rider (CSR) and the LG&E Interruptible Service, respectively. The hourly demand forecasts do not include the effects of existing or planned DSM programs.

Combined Companies

Energy Requirements

Graph CC-1 shows the Combined Companies' weather-normalized historic annual energy requirements and forecast. The combined energy requirements grew from 32,059 GWh in 2000 to 34,316 GWh in 2004 (weather-normalized), an increase of 2,257 GWh. The combined energy requirements are forecast to grow from 34,468 GWh in 2005 to 37,462 GWh in 2009, an average annual growth rate of 2.1 percent. This growth adds 2,993 GWh to the requirements over the period, or an average annual growth of 748 GWh. Over the long term (2005 to 2019), energy requirements are forecast to grow to 45,306 GWh, which is an average annual rate of 2.0 percent.

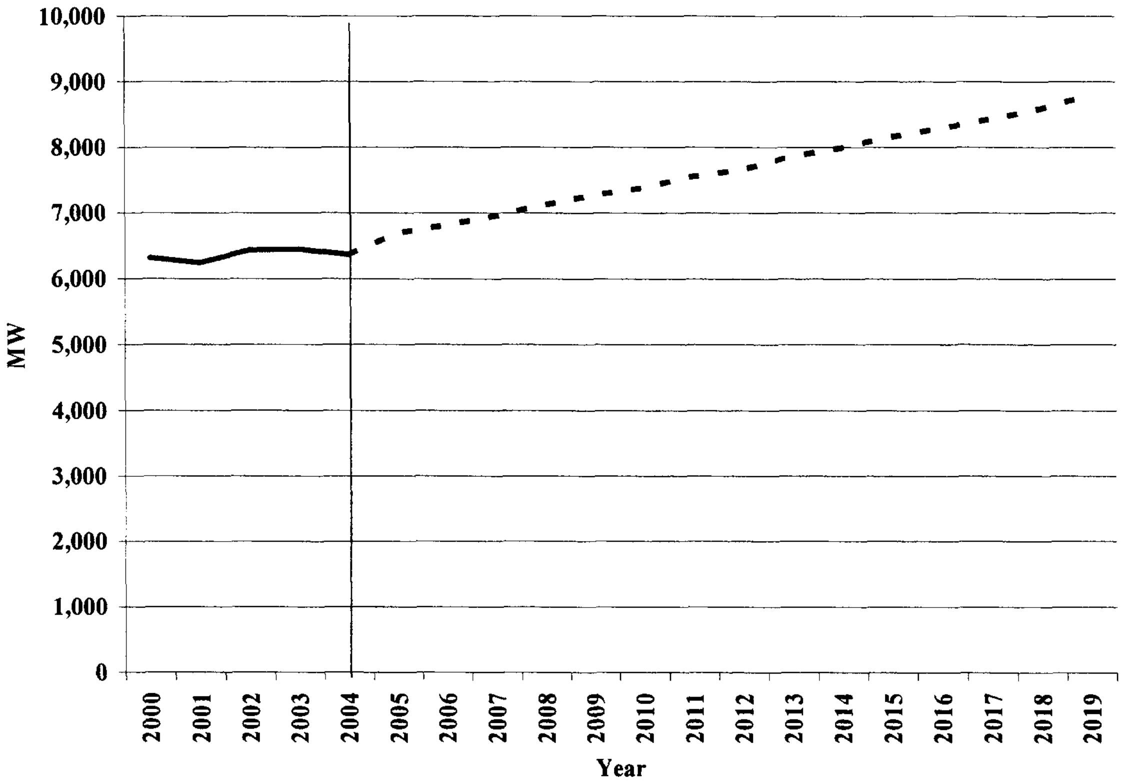
GRAPH: CC-1
COMBINED COMPANY ENERGY REQUIREMENTS
HISTORY & FORECAST (GWh)



Demand Forecast

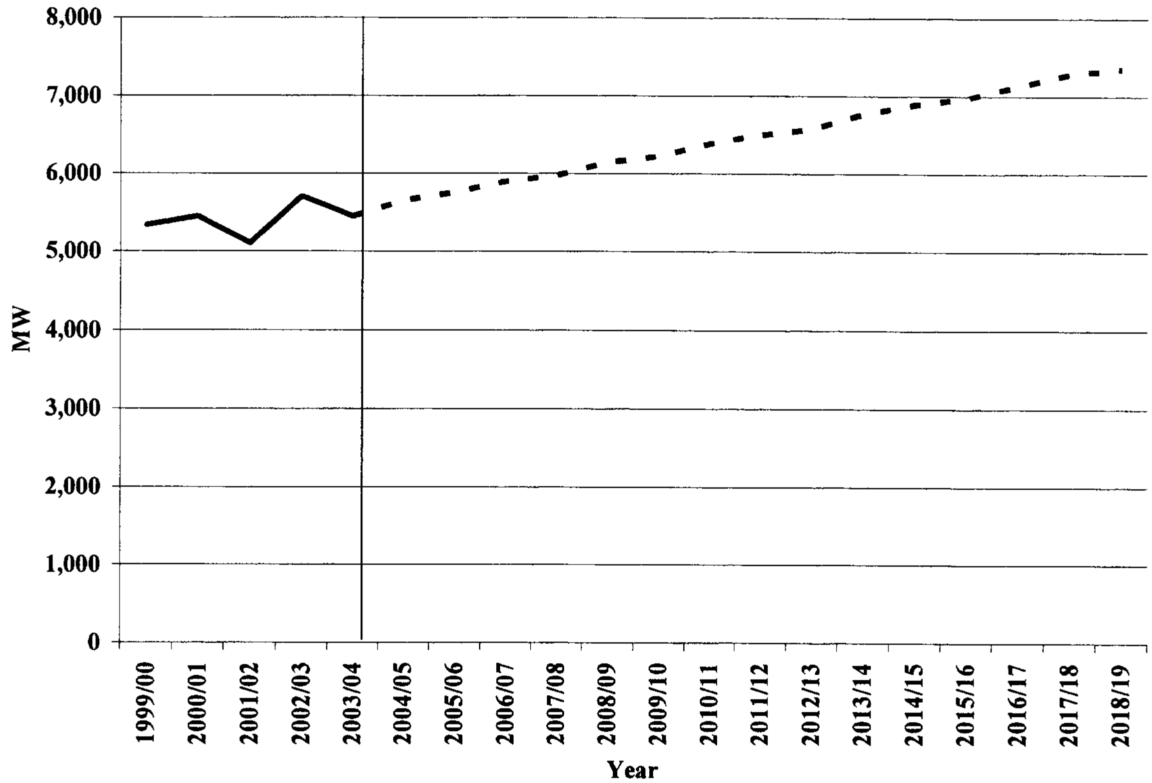
Graph CC-2 shows the combined companies' historic weather-normalized summer peak demand and forecast after the projected Curtailable Service Rider and Interruptible reductions. Curtailable and Interruptible reductions are forecast to be 100 MW. The Combined Companies' summer peak demand is forecast to increase at an average annual rate of 2.0 percent from 6,696 MW in 2005 to 8,794 MW in 2019, adding 2,098 MW over the period at an average of 150 MW per year. Between 2005 and 2009, summer peak demand is forecast to increase from 6,696 MW to 7,272 MW, an average annual rate of 2.1 percent, adding 576 MW over the period at an average of 144 MW per year. For the 2005-2019 period, summer peak demand is forecast to increase at an average annual rate of 2.0 percent from 7,272 MW to 8,794 MW, adding 1,522 MW over the period at an average of 152 MW per year.

GRAPH: CC-2
COMBINED COMPANY SUMMER PEAK DEMAND
HISTORY & FORECAST(MW)



Graph CC-3 shows the Combined Companies' winter peak demand. Winter peak demand is forecast to increase at an average annual rate of 1.9 percent from 5,647 MW in 2004/05 to 7,355 MW in 2018/19 period, adding 1,708 MW over the period at an average of 122 MW per year. Between 2004/05 and 2008/09, the winter peak demand is forecast to increase from 5,647 MW to 6,142 MW, an average annual rate of 2.1 percent, adding 495 MW over the period at an average of 124 MW per year.

GRAPH CC-3
COMBINED COMPANY WINTER PEAK DEMAND HISTORY & FORECAST(MW)



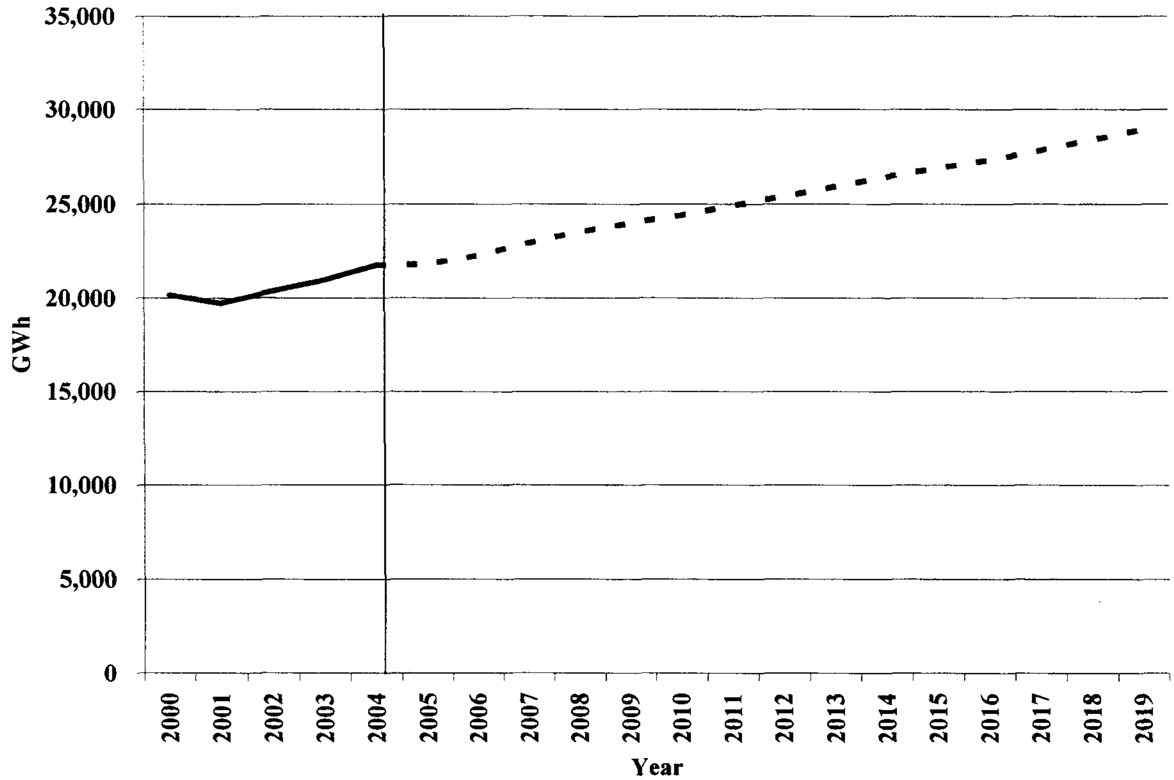
Kentucky Utilities

Energy Requirements

Graph KU-1 shows the weather-normalized historic annual energy requirements and forecast. KU's weather-normalized energy requirements decrease from 20,178 GWh in 2000 to 19,711 GWh in 2001 due in part to the recession in that year. From 2000 to 2004, energy requirements grew 1,586 GWh to 21,764 GWh. KU's energy requirements are forecast to grow from 21,812 GWh in 2005 to 23,983 GWh in 2009, an average annual rate of 2.4 percent. This growth adds 2,171 GWh to the requirements over the period, or an average annual growth of 543 GWh. Between 2009 and 2019, energy requirements are forecast to grow from 23,983 GWh to

28,933 GWh, an increase of 4,950 GWh, at an average annual growth rate of 1.9 percent. This growth represents an annual growth of 495 GWh.

GRAPH KU-1
KU ENERGY REQUIREMENTS
HISTORY & FORECAST(GWh)



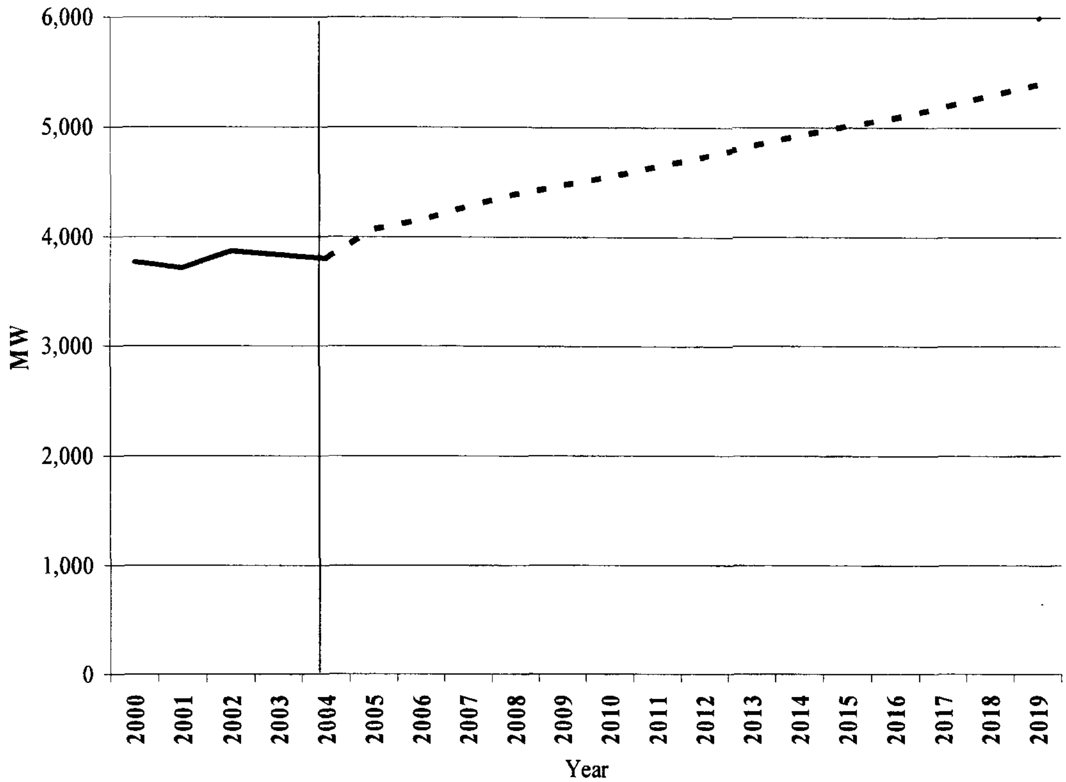
Demand Forecast

Graph KU-2 shows KU's historic weather-normalized summer peak demand and forecast after the projected CSR reductions. CSR reductions are forecast to be 51 MW in the summer.

KU's recorded summer peak demand grew from 3,775 MW in 2000 to 3,899 MW in 2002, before declining to 3,744 MW in 2004. On a weather-normalized basis, the summer peak demand increased from 3,772 MW in 2000 to 3,870 MW in 2002 before declining to 3,800 MW in 2004. The increase between 2000 and 2004 was 28 MW.

KU summer peak demand is forecast to increase at an average annual rate of 1.9 percent from 4,067 MW in 2005 to 5,393 MW in 2019 period, adding 1,326 MW over the period at an average of 95 MW per year. Between 2005 and 2009, the summer peak demand is forecast to increase from 4,067 MW to 4,472 MW, an average annual rate of 2.4 percent, adding 405 MW over the period at an average of 101 MW per year. For the 2009 to 2019 period, the summer peak demand is forecast to increase at an average annual rate of 1.9 percent from 4,472 MW to 5,393 MW, adding 921 MW over the period at an average of 92 MW per year.

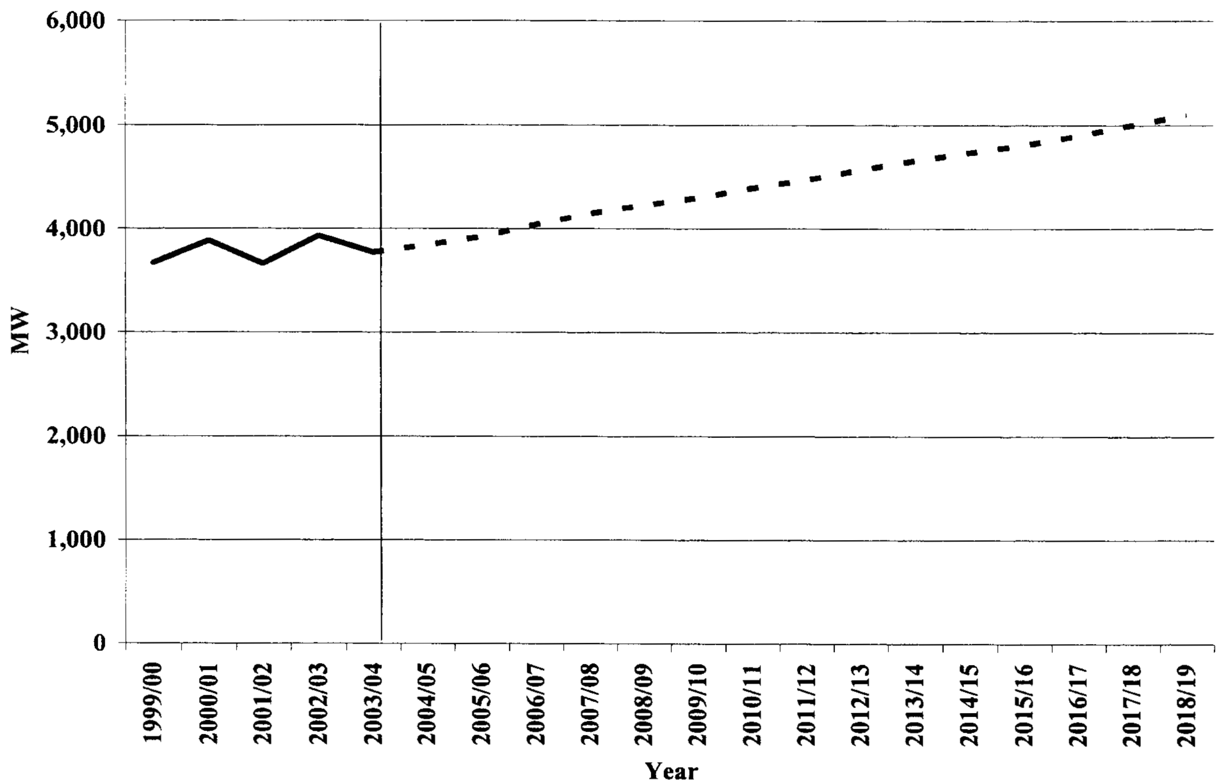
GRAPH KU-2
KU SUMMER PEAK DEMAND
HISTORY & FORECAST(MW)



Graph KU-3 shows KU's weather-normalized historical winter peak demand and forecast after projected CSR reduction of 38 MW. KU winter peak demand grew from 3,665 MW in 1999/2000 to 3,768 MW in 2003/04, a 103 MW increase over the period. On a weather-normalized basis, the winter peak decreased from 3,925 MW in 1999/2000 to 3,771 MW in 2003/04, a decrease of 154 MW over the period, or an annual decrease of 39 MW.

KU winter peak demand is forecast to increase at an annual rate of 2.0 percent from 3,842 MW in 2004/05 to 5,097 MW in 2018/19 period, adding 1,255 MW. Between 2004/05 and 2008/09, the winter peak demand is forecast to increase from 3,842 MW to 4,225 MW, an average annual growth rate of 2.4 percent, adding 383 MW over the period at an average of 96 MW per year.

GRAPH KU-3
KU WINTER PEAK DEMAND
HISTORY & FORECAST(MW)

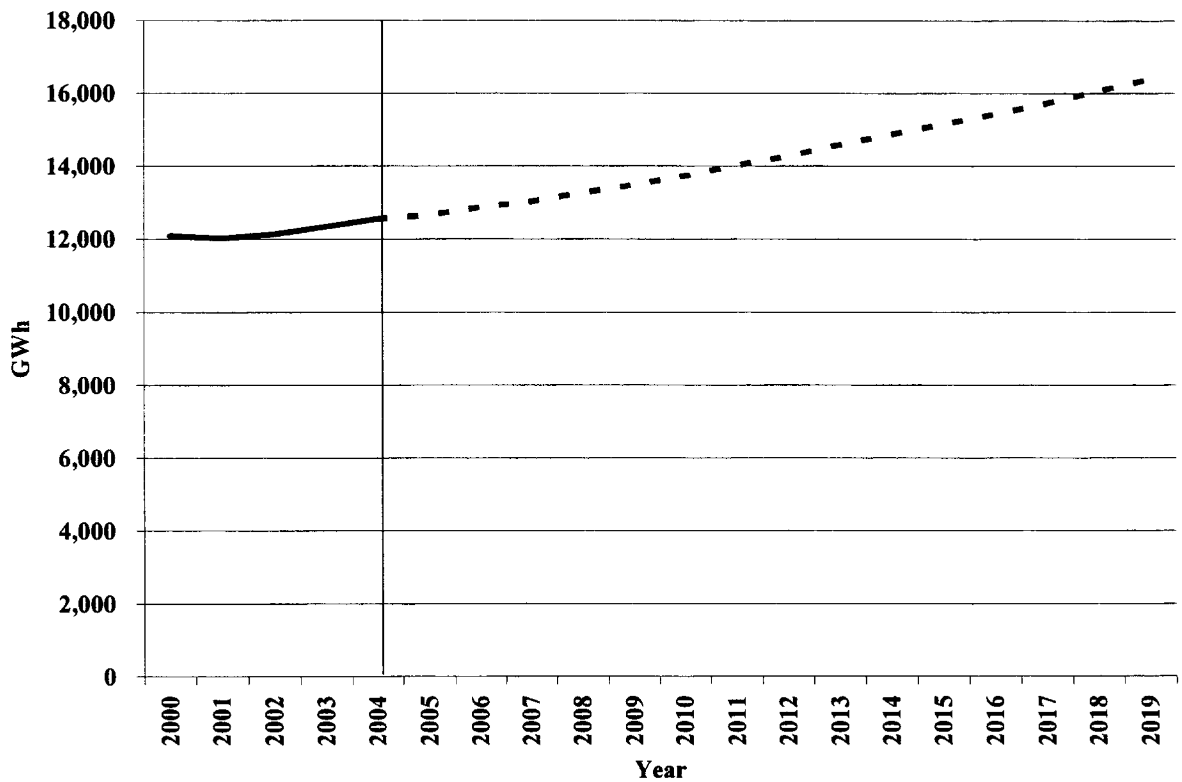


Louisville Gas & Electric

Energy Requirements

Graph LG&E-1 shows LG&E's weather-normalized historic annual energy requirements and forecast. LG&E's energy requirements fluctuated from 12,083 GWh in 2000 to 12,129 GWh in 2002 and then increased to 12,335 GWh in 2003 and to 12,552 GWh in 2004 (weather-normalized). LG&E's energy requirements are forecast to grow from 12,657 GWh in 2005 to 13,478 GWh in 2009, an average annual rate of 1.6%. This growth adds 821 GWh to the energy requirements over this period, at an average annual growth of 205 GWh. Between 2005 and 2019, energy requirements are forecast to reach 16,374 GWh, an annual average increase of 1.9 percent.

GRAPH LG&E-1
LG&E ENERGY REQUIREMENTS
HISTORY & FORECAST(GWh)



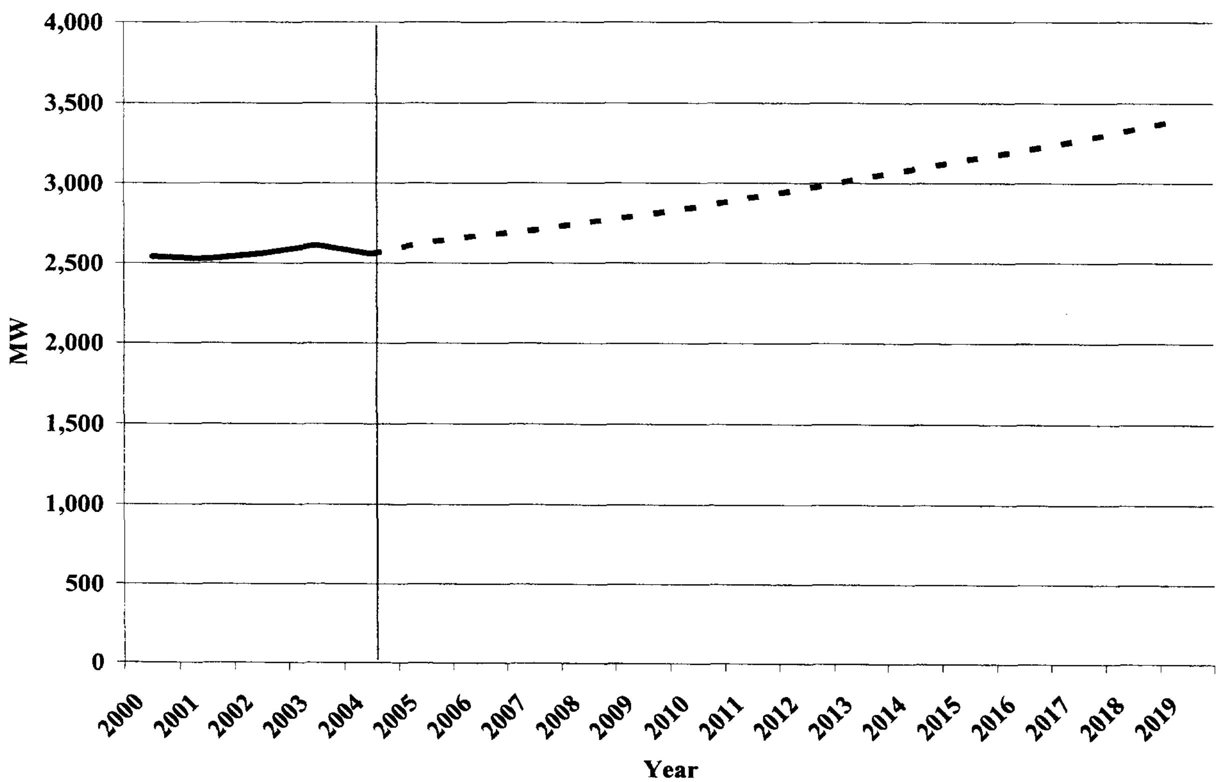
Demand Forecast

Graph LG&E-2 shows LG&E's weather-normalized historic summer peak demand and forecast after the projected Interruptible reductions. Interruptible reductions are forecasted to be 49 MW.

LG&E's summer peak demand grew from 2,542 MW in 2000 to 2,623 MW in 2002 before declining to 2,485 MW in 2004. On a weather-normalized basis, summer peak increased from 2,542 MW in 2000 to 2,562 MW in 2004, an increase of 20 MW representing an average annual growth rate of 0.2 per cent.

The LG&E summer peak demand forecast increases at an average annual rate of 1.9 percent from 2,629 MW in 2005 to 3,401 MW in 2019, adding 772 MW over the period at an average of 55 MW per year. Between 2005 and 2009, summer peak demand is forecast to increase from 2,629 MW to 2,800 MW, an average annual rate of 1.6 percent, adding 171 MW over the period at an average of 43 MW per year.

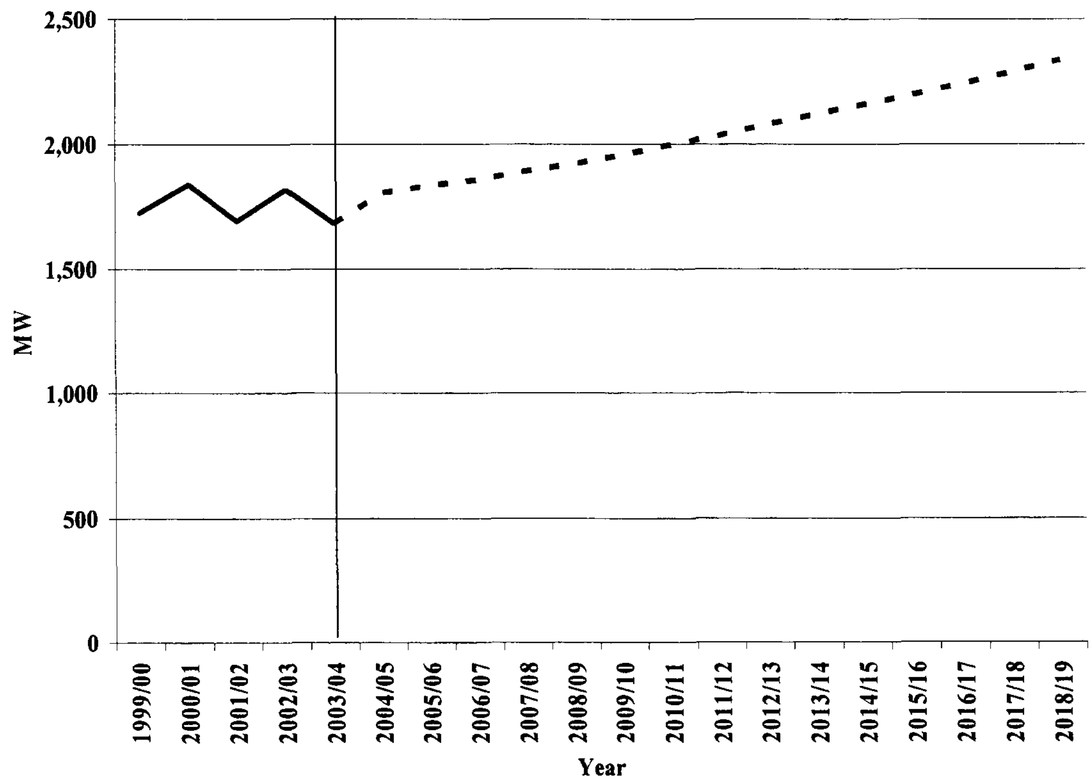
GRAPH LG&E-2
LG&E SUMMER PEAK DEMAND
HISTORY & FORECAST(MW)



Graph LG&E-3 shows LG&E's weather-normalized historic winter peak demand and forecast. The winter peak demand grew from 1,670 MW in 1999/2000 to 1,750 MW in 2003/04. On a weather-normalized basis, there was a decline of 41 MW over the period, with a decline in the winter peak from 1,724 MW in 1999/2000 to 1,683 MW in 2003/04, a decrease of 41 MW.

The LG&E winter peak demand is forecast to increase at an average annual rate of 1.9 percent from 1,805 MW in 2004/05 to 2,335 MW in 2018/19 period, adding 530 MW over the period at an average of 38 MW per year. Between 2004/05 and 2008/09, the winter peak demand is forecasted to increase from 1,805 MW to 1,922 MW, an average annual growth rate of 1.6 percent, adding 117 MW over the period at an average of 29 MW per year.

GRAPH LG&E-3
LG&E WINTER PEAK DEMAND
HISTORY & FORECAST(MW)



DEMAND FORECAST METHODOLOGY

Change to the utilities' demand forecasts since the 2002 IRP reflects changes in the KU and LG&E energy forecasts and certain changes in peak demand forecasting methodology. In addition, the uncurtailed peak is impacted by changes in the assumed level of curtailable and interruptible contracts. Review of the energy forecast changes can be found in *Technical Appendix 1, the 2005-2019 KU Energy Forecast Report* and in *Technical Appendix* 2, the *2005-2019 LG&E Energy Forecast Report.* The following section outlines changes in the peak forecasting methodology in the 2005 IRP forecast.

Changes in Peak Demand Forecasting Methodology

The process of forecasting peak demand in the 2005 IRP forecast incorporates two methodological changes from the previous IRP. These changes relate to the processes of:

i. converting the forecast of energy sales from a billing cycle basis to a calendar month basis; and
ii. translating the forecast of (calendar) monthly energy sales to a projection of hourly load (and hence peak demand).

Conversion of Monthly Sales Forecast from Billed to Calendar Basis

Since the detailed history of energy sales -- by company and by customer class – is available only on a billing-cycle basis (i.e. customer records reflect sales billed in each month rather than energy delivered), the energy forecasting process produces a projection of sales which, in its initial formulation, is likewise expressed on a billing-cycle basis. To develop a projection of peak demand that reflects the pattern of energy *delivered* in each month rather than the pattern of energy *billed*, the forecast of billed sales is first converted to a calendar month basis.

At the time of the 2002 IRP, predicted daily utility loads were used to apportion energy to calendar months from billing periods. The results were allocation factors that summed to one for a given billing period. A given factor times the corresponding billing month's energy forecast would result in the expected calendar month energy.

In the 2005 IRP, the annual forecast of billed sales is converted to a calendar-year basis by adding an estimate of net unbilled sales to total billed sales for the year. Net unbilled sales for the year represent the difference between gross unbilled sales at the end of the current year and gross unbilled sales at the end of the prior year. Gross unbilled sales at the end of the current year are estimated by application of the ratio of unbilled to billed sales from the previous December.

The resulting annual calendar sales are then allocated to months using monthly to annual ratios that are based on twenty-year average ratios of January to December monthly energy requirements to total annual energy requirements. Losses are added to calendar monthly energy sales to complete the forecast of energy requirements for each month. The loss factors used are from a line loss study undertaken for the Utilities by Management Application Consultants (also used in the Companies' 2004 Rate Case). Average losses are estimated at 5.9% for KU and at 5.3% for LG&E (both expressed as a percentage of energy sent out).

This change in the methodology to convert the energy forecast from a billed basis to a calendar basis was adopted to remove the influence of billing cycle forecasts on the predicted daily loads. Billing cycle forecasts depend on meter reading days which in turn are governed by different rules for each of the utilities.

Translation of energy sales to hourly load profile

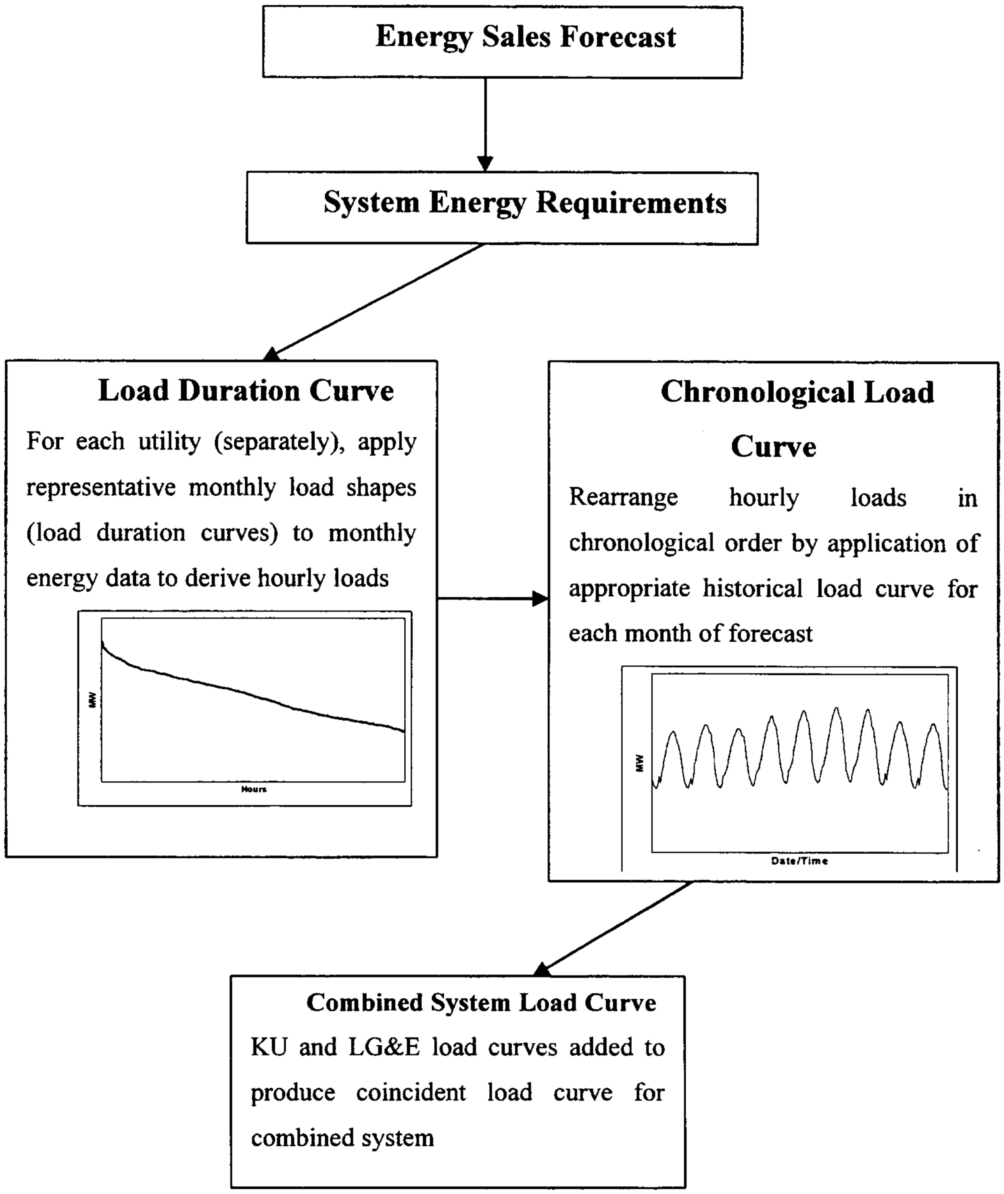
Figure 1 illustrates how the Companies' monthly energy forecast is converted into a chronological projection of hourly system loads which determines the Companies' annual peak demand. Since system peak demand is measured at the generator bus bar, the forecast of energy sales to customers is adjusted for transmission and distribution system losses. The monthly energy requirement forecast (including losses) is then converted into an hourly load duration curve using a representative curve reflecting the historical average hourly load pattern for the same month. In the 2002 IRP forecast, the 'representative' monthly load curve was that of a single month – from a 20-year record – in which conditions most closely matched the normal (average daily) temperature for that month over the historical record.[1] In the 2005 IRP forecast, the duration curve represents an averaged normalized curve compiled from the records for the

1 The selection was constrained to the extent that the same historic month was used as the reference for both utilities to preserve the appropriate degree of peak coincidence between the two systems.

relevant month over the last ten years. The use of an averaged load duration curve removes the risk – inherent in the application of any single historical year – of replicating an anomalous pattern over the forecast period, and also results in a more consistent relationship between monthly peak demands.

As before, the resultant monthly load duration curves in the 2005 IRP forecast are converted to chronological load curves (*i.e.*, the hourly loads are re-arranged in chronological order rather than by order of magnitude) by application of an appropriate historical load curve which: (a) captures the calendar attributes of the forecast month in question (*i.e.*, the pattern of weekdays and weekends over the month); and (b) maintains the historic relationship of (approximate) peak coincidence between the two utilities. This latter condition of peak coincidence is particularly important for selection of the chronological curve for the peak month (July). Note that the selected historic load curve is used only to achieve a chronological sort of the ordinates from the load duration curve. At this point the chronological load curves of KU and LG&E are combined to create the total coincident load for the combined system. The hourly load forecast reflects the impact of interruptible loads.

FIGURE 1



Changes in Curtailable/Interruptible Loads

The historical record of energy sales and peak demand – the basis on which forward projections are developed – incorporates the effects of curtailment and interruption of supply by the utilities in accordance with the terms of existing curtailable (CSR) contracts. Thus, the projections of sales and peak demand include a component of 'embedded' load curtailment. To determine the level of uncurtailed demand, the aggregate of interruptible demands must be added to the curtailed forecast. (Note that this forecast of uncurtailed demand is used for reference purposes only and is not the benchmark forecast used for capacity planning purposes. The curtailed forecast is used for capacity planning.)

For the uncurtailed forecast, an adjustment is made for the amount of load assumed to be curtailable or interruptible (based on existing contracts) after native load demand is determined. Table CC-1 shows the changes in the assumed curtailable/interruptible loads from the 2002 IRP to the 2005 Forecast.

The KU CSR forecast called for 72 MW in the 2002 IRP. The CSR forecast has decreased by 21 MW for a total CSR load of 51 MW in the 2005 IRP. Although one new customer was added, the reduction in other customers' demand caused an overall decline. The LG&E interruptible forecast was 59 MW in the 2002 IRP but was reduced to 49 MW in the 2005 IRP.

TABLE CC-1
CURTAILABLE LOADS

	KU	**LG&E**	**Combined**
2002	**72**	**59**	**131**
Customers leaving	0	2	2
CSR/Int. reductions	21	11	32
New Customers	0	1	1
CSR/Int. additions	0	2	2
Net Change	**-21**	**-10**	**-31**
2005	**51**	**49**	**100**

UNCERTAINTY ANALYSIS

High and low hourly demand forecasts are developed based on the high and low sales forecast outlined in Appendix 1, the *2005-2019 KU Energy Forecast* report and in Appendix 2, the *2005-2019 LG&E Energy Forecast* report. The high and low peak demands assume the same load factor as the base load forecast.

Combined Companies

Table CC-2 compares the high and low peak demands with the base case.

TABLE CC-2
COMBINED COMPANY BASE, HIGH, AND LOW PEAK DEMAND FORECASTS
(MW)

Year	Base Peak	High Peak	Low Peak
2005	6,696	6,748	6,623
2006	6,811	6,898	6,703
2007	6,951	7,074	6,803
2008	7,125	7,288	6,935
2009	7,272	7,471	7,044
2010	7,383	7,618	7,122
2011	7,556	7,831	7,250
2012	7,662	7,974	7,321
2013	7,859	8,215	7,470
2014	7,993	8,390	7,565
2015	8,159	8,597	7,689
2016	8,292	8,768	7,785
2017	8,430	8,947	7,882
2018	8,587	9,148	7,991
2019	8,794	9,402	8,149

Kentucky Utilities

Table KU-1 compares the high and low peak demands with the base case.

TABLE KU-1
BASE, HIGH, AND LOW PEAK DEMAND FORECASTS (MW)

Year	Base Peak	High Peak	Low Peak
2005	4,067	4,093	4,017
2006	4,153	4,198	4,081
2007	4,275	4,347	4,173
2008	4,387	4,481	4,258
2009	4,472	4,586	4,321
2010	4,549	4,681	4,379
2011	4,646	4,798	4,451
2012	4,731	4,901	4,515
2013	4,830	5,022	4,590
2014	4,925	5,137	4,662
2015	5,012	5,244	4,727
2016	5,089	5,338	4,784
2017	5,184	5,454	4,856
2018	5,290	5,582	4,936
2019	5,393	5,708	5,014

Louisville Gas & Electric

Table LG&E-1 Base compares the high and low peak demands with the base case.

TABLE LG&E-1
BASE, HIGH, AND LOW PEAK DEMAND FORECASTS (MW)

Year	Base Peak	High Peak	Low Peak
2005	2,629	2,655	2,606
2006	2,673	2,715	2,636
2007	2,705	2,757	2,659
2008	2,756	2,825	2,694
2009	2,800	2,885	2,723
2010	2,850	2,953	2,759
2011	2,910	3,033	2,799
2012	2,964	3,106	2,836
2013	3,029	3,193	2,880
2014	3,088	3,273	2,921
2015	3,147	3,353	2,962
2016	3,203	3,430	3,001
2017	3,264	3,512	3,043
2018	3,333	3,604	3,089
2019	3,401	3,694	3,135