Table of Contents

6. SIGNIFICANT CHANGES

All integrated resource plans shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.

The plan most recently filed is the 2002 Joint IRP of LG&E and KU. Several significant changes have taken place since that filing, as reviewed in this section. Some changes were initiated in response to the PSC *Staff Report on the 2002 Joint Integrated Resource Plan of the Louisville Gas and Electric Company and Kentucky Utilities Company* dated December 2003. The major changes in the 2005 IRP from the 2002 plan are described in the sections that follow.

Resource Assessment and Acquisition Plan

The resource assessment and acquisition plan is developed based on the Companies' combined integrated electric system. The 2002 plan recommended the completion of four 148 MW combustion turbines at the Trimble County station in 2004-2006 (two in 2004, one in 2005, and one in 2006), with two additional 148 MW Greenfield combustion turbines in 2007, 75% of a 732 MW supercritical coal unit at Trimble County station in 2008, four more 148 MW Greenfield combustion turbines in years 2012-2014 (two in 2012, one in 2013, and one in 2014), and finally the installation of a phased-construction combined cycle combustion turbine of 474 MW size in 2016.

Since the 2002 IRP, the Companies have installed four 160 MW combustion turbines at Trimble County. Units 7 and 8 commenced commercial operation in June 2004 and Units 9 and 10 in July 2004.

The 2005 IRP continues the trend of adding additional combustion turbines to the system. However, as indicated in Table 5.(4) and discussed in detail in Section 8.(4), the supercritical coal unit at Trimble County is currently recommended for installation in 2010. After adding 2,065 MW of peaking combustion turbine capacity to the system since the last baseload plant was installed in 1990, additional baseload generation is required to economically and reliably serve native load customers. Since the 2002 IRP the Companies' continuous resource planning process has monitored the resource plans and in most recent evaluations a coal unit was being identified in the least-cost expansion plan.

OVEC

The Ohio Valley Electric Corporation ("OVEC") was formed for the purpose of providing electric power requirements projected for the uranium enrichment complex being built near Portsmouth, Ohio. In 1993, the United States Enrichment Corporation ("USEC") was formed to lease the uranium enrichment facilities from the Department of Energy ("DOE") and assume the responsibility for uranium enrichment services for the USA. DOE gave notice of reductions in its contract demand for electricity, with power and energy no longer requested after August 31, 2001. The power and energy thus released from the plants became available to the Sponsoring Companies under the Inter-Company Power Agreement ("ICPA"). OVEC's Kyger Creek Plant at Cheshire, Ohio and IKEC's Clifty Creek Plant at Madison, Indiana have generating capacities of 1,075 MW and 1,290 MW, respectively.

Upon formation of OVEC, LG&E sponsored 7.0% and KU sponsored 2.5% of the power participation benefits in the OVEC project. This equates to a combined 9.5% capacity and energy share for the Companies, or roughly 225 MW of the total gross capacity. However, for planning purposes, the Companies rely upon 209 MW net during the summer peak and varying capacity during the remaining months due to unit maintenance schedules on the OVEC system.

The 15 sponsors of OVEC entered the ICPA at the formation of OVEC. Under the ICPA, each sponsoring company undertook certain obligations, including the contractual obligation to make up power shortages to the Portsmouth facility, and had the contractual right to "surplus" OVEC power, all in accordance with each sponsor's Power Participation Ratio ("PPR"). This ICPA will expire March 12, 2006.

When the ICPA expires in 2006, KU will retain its 2.5% ownership. Beginning in April 2006, LG&E's portion of the power participation benefits will become 5.63% pursuant to the Amended and Restated ICPA dated as of March 13, 2006 filed with and approved by the Commission in Case No. 2004-00396. Hence, beginning April 2006, the anticipated summer peak the Companies will rely upon from OVEC is 179 MW net, with varying capacity during the remaining months due to unit maintenance schedules on the OVEC system.

LOAD FORECAST

The following discussion presents the changes in the energy and demand forecasts for the Combined Companies, and for Kentucky Utilities and Louisville Gas & Electric.

Summary of Forecast Changes

Combined Company

Compared to the 2002 IRP, the current Combined Companies' energy forecast for the 2005-2009 period has been reduced by approximately 1,100 GWh per year (or 3.0 percent), although the average growth rate remains about the same (2.1 percent). Through 2019, the reduction is slightly greater (1,150 GWh), but the growth rate remains virtually the same at 2.0

percent for both forecasts. The magnitude of reduction for each year is shown in Table 6.(1)-1 and in Graph 6.(1)-1. The revised forecast reflects, in part, the impact on energy sales of the economic slowdown that began in 2001, and the weakness of the recovery.

Table 6.(1)-1

Comparison of Combined Companies' 2005 and 2002 IRP Energy and Demand Forecasts

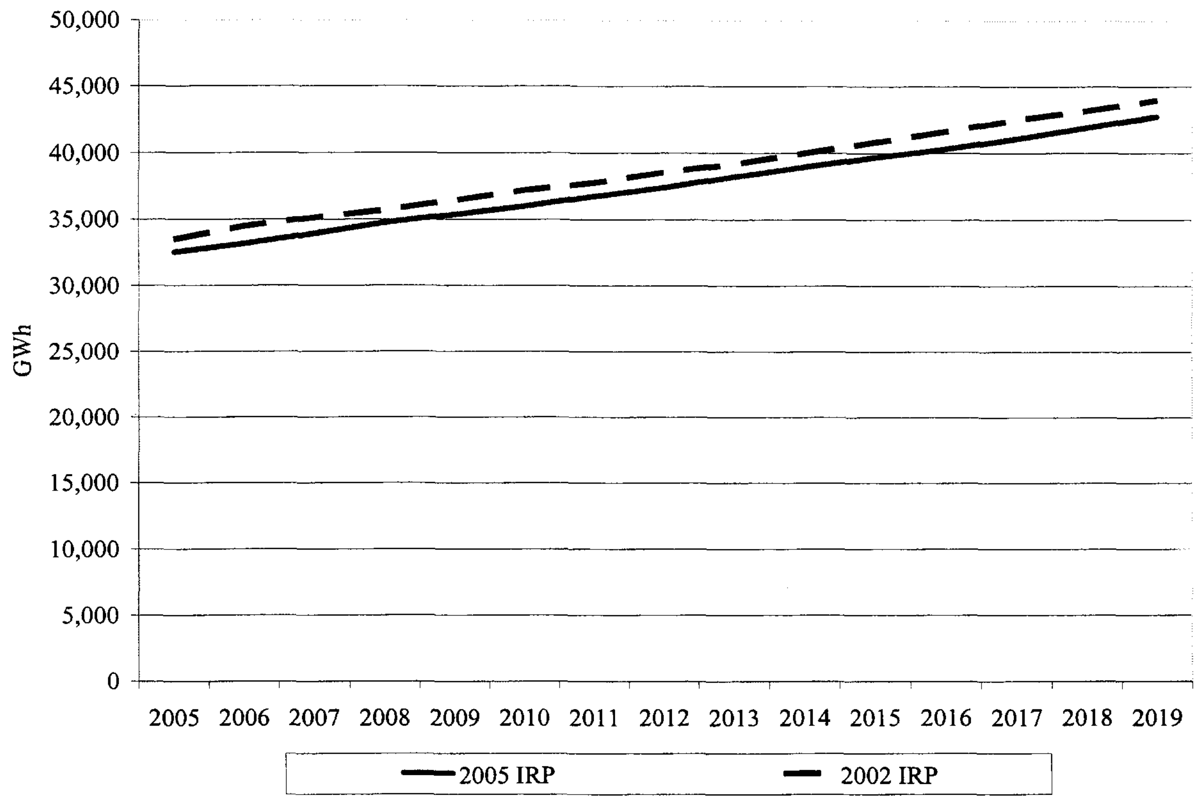
Year	Combined Companies' Energy Sales (GWh) [1]			
	2005 IRP	2002 IRP	Change	% Change
2005	32,522	33,501	-979	-2.9%
2006	33,160	34,455	-1,295	-3.8%
2007	33,922	35,105	-1,183	-3.4%
2008	34,716	35,674	-958	-2.7%
2009	35,343	36,439	-1,096	-3.0%
2010	35,966	37,181	-1,215	-3.3%
2011	36,728	37,753	-1,025	-2.7%
2012	37,401	38,543	-1,142	-3.0%
2013	38,200	39,167	-967	-2.5%
2014	38,948	39,987	-1,039	-2.6%
2015	39,653	40,806	-1,153	-2.8%
2016	40,300	41,606	-1,306	-3.1%
2017	41,059	42,504	-1,445	-3.4%
2018	41,907	43,162	-1,255	-2.9%
2019	42,739	43,986	-1,247	-2.8%
2005-2009 AVG	2.1%	2.1%	-1,102	-3.2%
2005-2019 AVG	2.0%	2.0%	-1,154	-3.0%
Year	**Combined Companies' Peak Demand (MW) [2]**			
	2005 IRP	**2002 IRP**	**Change**	**% Change**
2005	6,696	7,078	-382	-5.4%
2006	6,811	7,274	-463	-6.4%
2007	6,951	7,488	-537	-7.2%
2008	7,125	7,604	-479	-6.3%
2009	7,272	7,674	-402	-5.2%
2010	7,383	7,850	-467	-5.9%
2011	7,556	8,011	-455	-5.7%
2012	7,662	8,250	-588	-7.1%
2013	7,859	8,339	-480	-5.8%
2014	7,993	8,494	-501	-5.9%
2015	8,159	8,571	-412	-4.8%
2016	8,292	8,806	-514	-5.8%
2017	8,430	8,994	-564	-6.3%
2018	8,587	9,248	-661	-7.1%
2019	8,794	9,346	-552	-5.9%
2005-2009 AVG	2.1%	2.0%	- 453	-6.1%
2005-2019 AVG	2.0%	2.0%	- 497	-6.1%

[1] Given on a calendar basis

[2] After reduction for Interruptible and Curtailable loads

Graph 6.(1)-1

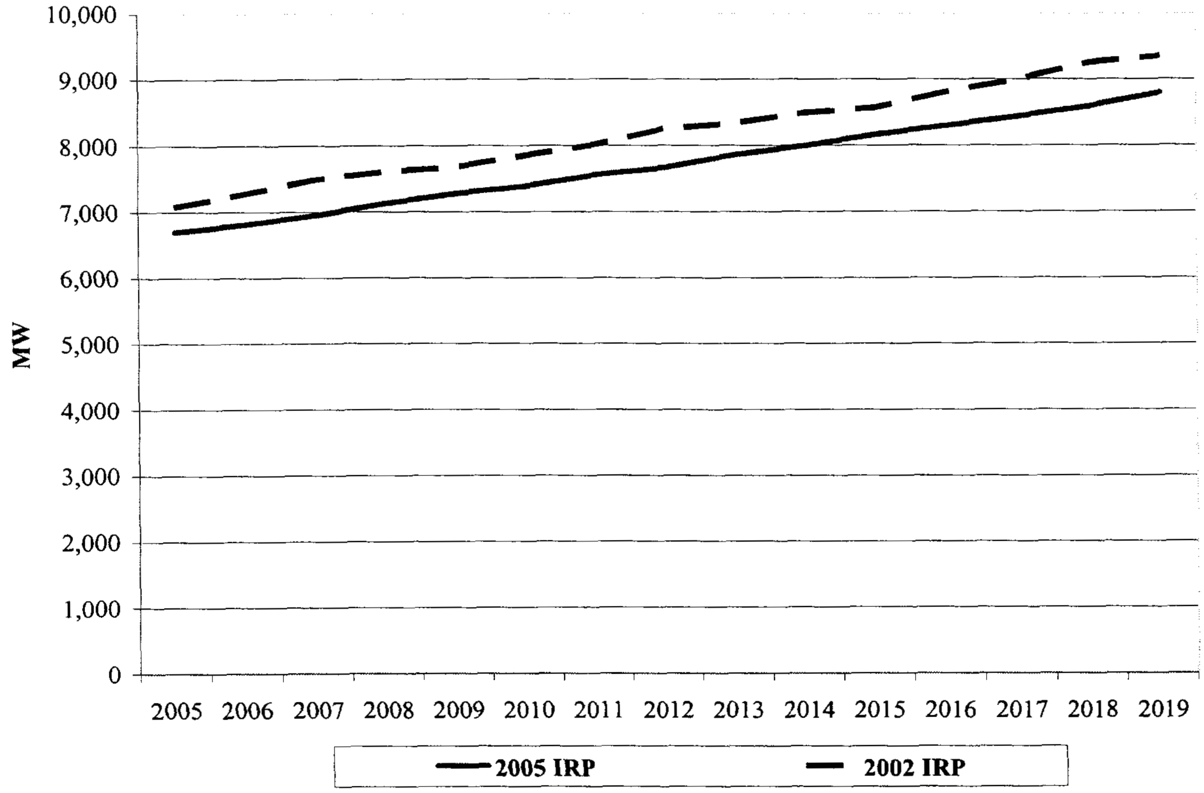
Combined Company Energy Sales - 2002 vs. 2005 IRP Forecasts (GWh)



The Combined Companies' peak demand forecast for the 2005-2009 period has been reduced by an average of 450 MW (or -6.0 percent) per year as compared to the 2002 IRP forecast. However, as in the case of the energy forecast, the growth rates between the two forecasts are similar, at just over 2.0 percent. This is displayed in Graph 6.(1)-2.

Graph 6.(1)-2

Combined Companies' Peak Demand Forecast – 2002 vs. 2005 IRP Forecasts (MW)



Kentucky Utilities

In the 2005 IRP forecast, KU sales in the 2005-2009 period are expected to be 669 GWh (on average) lower (-3.0 percent) each year as compared to the 2002 IRP energy forecast. Over the 2005-2019 time period, the 2005 IRP forecast is 838 GWh lower (-3.3 percent) than the 2002 IRP forecast on an average annual basis. The growth rates for the two forecasts are the same over the medium term and over the long term, 2.4 percent and 2.1 percent respectively. A comparison of the 2002 IRP and 2005 IRP forecasts is shown in Table 6.(1)-2 and in Graphs 6.(1)-3 and 6.(1)-4.

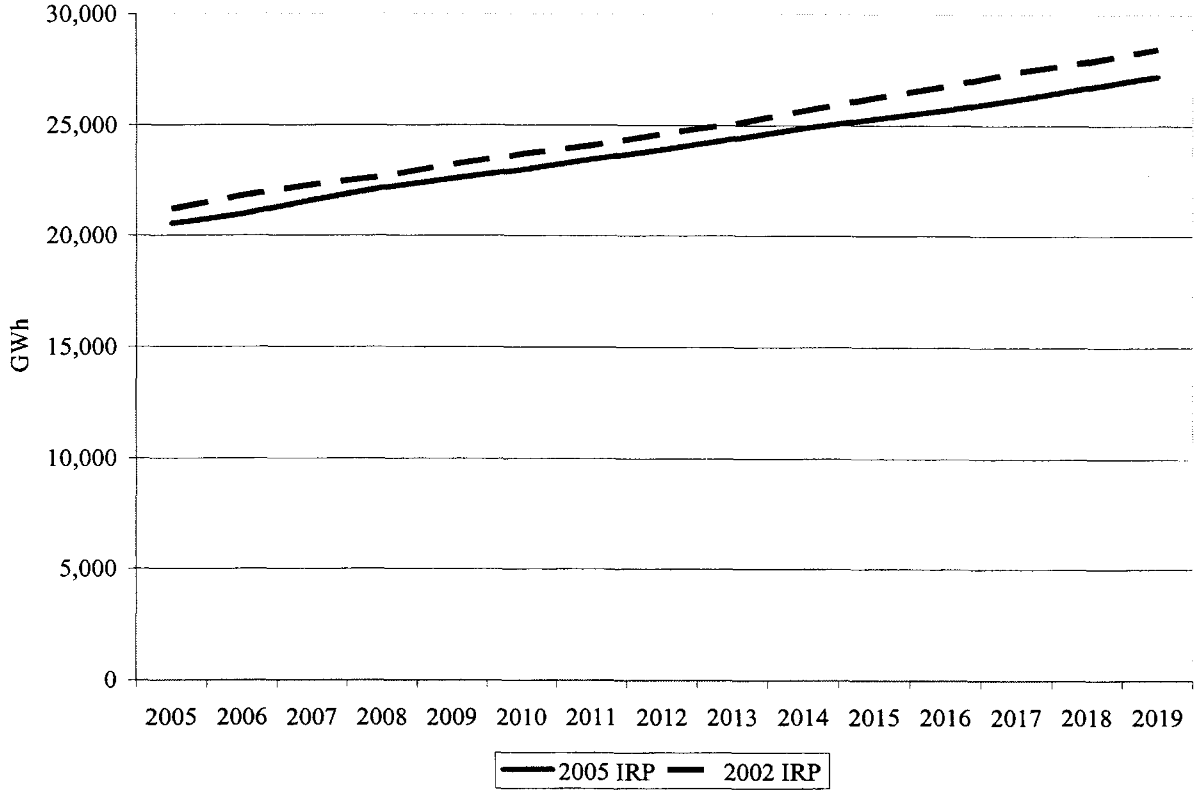
Table 6.(1)-2
Comparison of KU's 2002 IRP and 2005 IRP Energy and Demand Forecasts

Year	KU Total Energy Sales (GWh) 1			
	2005 IRP	2002 IRP	Change	% Change
2005	20,532	21,197	-665	-3.1%
2006	20,967	21,806	-839	-3.8%
2007	21,585	22,283	-698	-3.1%
2008	22,150	22,655	-505	-2.2%
2009	22,577	23,216	-639	-2.8%
2010	22,969	23,684	-715	-3.0%
2011	23,458	24,084	-626	-2.6%
2012	23,887	24,622	-735	-3.0%
2013	24,388	25,067	-679	-2.7%
2014	24,869	25,657	-788	-3.1%
2015	25,305	26,248	-943	-3.6%
2016	25,695	26,772	-1,077	-4.0%
2017	26,178	27,419	-1,242	-4.5%
2018	26,711	27,886	-1,176	-4.2%
2019	27,233	28,474	-1,241	-4.4%
2005-2009 AVG	2.4%	2.3%	- 669	-3.0%
2005-2019 AVG	2.0%	2.1%	- 838	-3.3%
Year	**KU Annual Peak Demand (MW)**			
	2005 IRP [2]	**2002 IRP**	**Change**	**% Change**
2005	4,067	4,309	-242	-5.6%
2006	4,153	4,435	-282	-6.4%
2007	4,275	4,603	-328	-7.1%
2008	4,387	4,651	-264	-5.7%
2009	4,472	4,725	-253	-5.4%
2010	4,549	4,845	-296	-6.1%
2011	4,646	4,941	-295	-6.0%
2012	4,731	5,155	-424	-8.2%
2013	4,830	5,146	-316	-6.1%
2014	4,925	5,253	-328	-6.2%
2015	5,012	5,329	-317	-5.9%
2016	5,089	5,482	-393	-7.2%
2017	5,184	5,620	-436	-7.8%
2018	5,290	5,834	-544	-9.3%
2019	5,393	5,836	-443	-7.6%
2005-2009 AVG	2.4%	2.3%	- 274	-6.0%
2005-2019 AVG	2.0%	2.2%	- 344	-6.7%

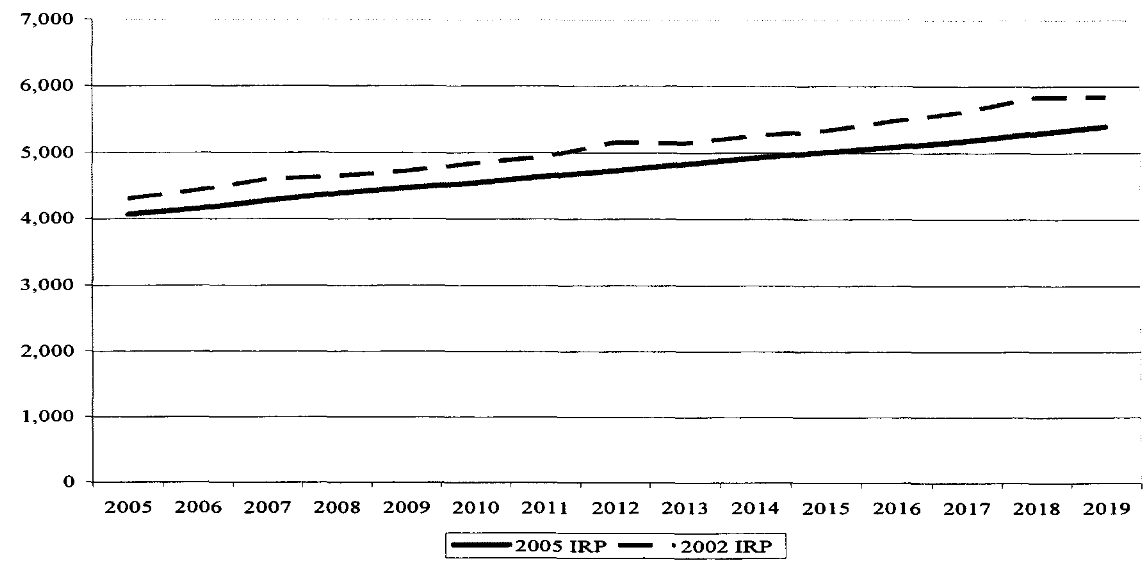
[1] Calendar basis

[2] Includes annual reduction of 51 MW for curtailable loads.

Graph 6.(1)-3
KU 2005 vs. 2002 IRP Energy Sales Forecast Comparison (GWh)



Graph 6.(1)-4
KU 2005 vs. 2002 IRP Peak Demand Forecast Comparison (MW)



Louisville Gas & Electric

The 2005 IRP forecast for LG&E sales in the 2005-2009 time period is 432 GWh lower than the 2002 IRP each year on average (-3.0 percent). Over the 2005-2019 time period, the 2005 IRP forecast is 316 GWh lower than the 2002 IRP on an average annual basis. The growth rates are similar between the two forecasts: in the medium term, the 2005 IRP energy forecast has an average growth of 1.6 percent, compared to the 2002 IRP forecast of 1.8 percent. In the long term, the growth rate for the 2005 IRP forecast is 1.9 percent, compared to 1.7 percent for the 2002 IRP forecast. Compared to the 2002 IRP forecast of peak demand, the 2005 IRP is on the average 227 MW lower per year over the 2005-2019 forecast period. These are shown in Table 6.(1)-3 and Graphs 6.(1)-5 and -6.

Table 6.(1)-3
Comparison of LG&E's 2005 IRP and 2002 IRP Energy and Demand Forecasts

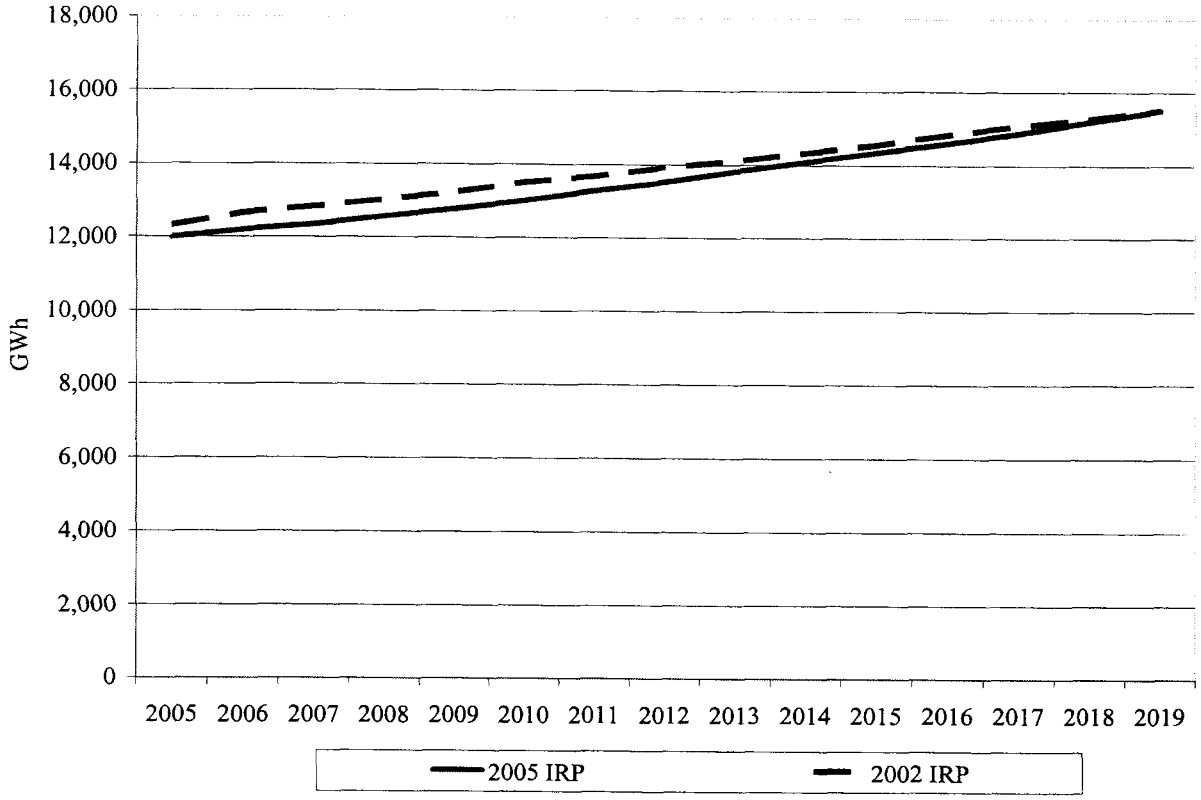
Year	LG&E Total Energy Sales (GWh) [1]			
	2005 IRP	2002 IRP	Change	% Change
2005	11,991	12,304	-313	-2.5%
2006	12,193	12,649	-456	-3.6%
2007	12,337	12,822	-485	-3.8%
2008	12,566	13,019	-453	-3.5%
2009	12,766	13,223	-457	-3.5%
2010	12,997	13,497	-500	-3.7%
2011	13,270	13,669	-399	-2.9%
2012	13,514	13,921	-407	-2.9%
2013	13,812	14,100	-288	-2.0%
2014	14,079	14,330	-252	-1.8%
2015	14,349	14,558	-209	-1.4%
2016	14,605	14,834	-229	-1.5%
2017	14,881	15,084	-203	-1.3%
2018	15,197	15,276	-79	-0.5%
2019	15,506	15,512	-6	0.0%
2005-2009 AVG	1.6%	1.8%	- 433	-3.4%
2005-2019 AVG	1.9%	1.7%	- 316	-2.3%

Year	LG&E Annual Peak Demand (MW)			
	2005 IRP [2]	2002 IRP	Change	% Change
2005	2,629	2,832	-203	-7.2%
2006	2,673	2,904	-231	-8.0%
2007	2,705	2,963	-258	-8.7%
2008	2,756	3,021	-265	-8.8%
2009	2,800	3,056	-256	-8.4%
2010	2,850	3,095	-245	-7.9%
2011	2,910	3,143	-233	-7.4%
2012	2,964	3,205	-241	-7.5%
2013	3,029	3,268	-239	-7.3%
2014	3,088	3,318	-230	-6.9%
2015	3,147	3,363	-216	-6.4%
2016	3,203	3,405	-202	-5.9%
2017	3,264	3,457	-193	-5.6%
2018	3,333	3,528	-195	-5.5%
2019	3,401	3,596	-195	-5.4%
2005-2009 AVG	1.6%	1.9%	- 243	-8.2%
2005-2019 AVG	1.9%	1.7%	- 227	-7.1%

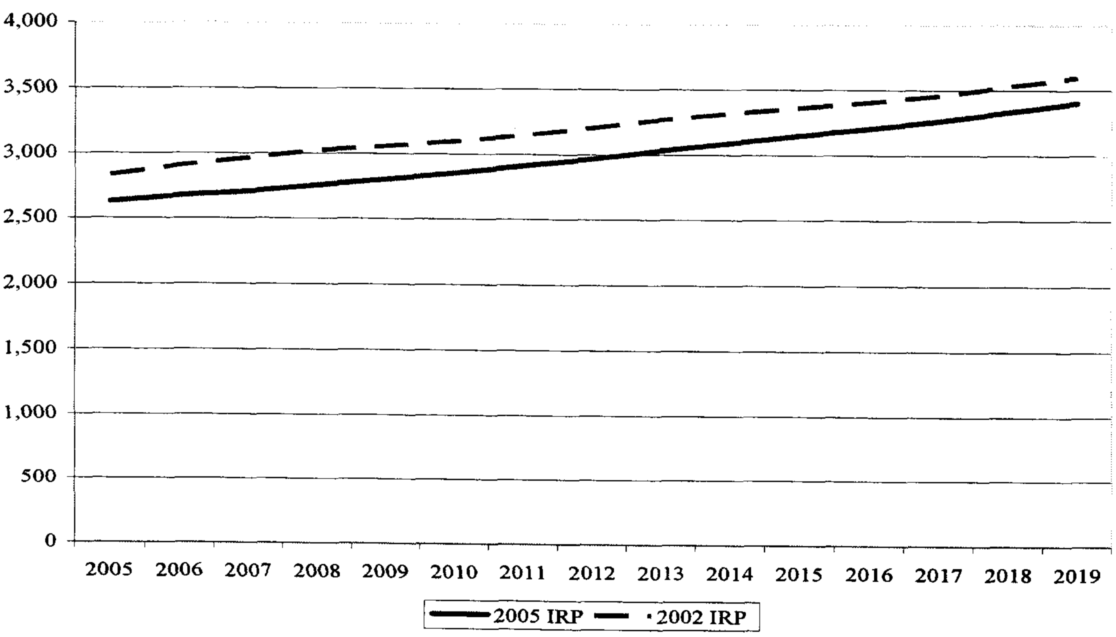
[1] Given on a calendar basis

[2] Includes annual reduction of 49 MW for interruptible loads.

Graph 6.(1)-5
LG&E 2005 vs. 2002 IRP Energy Sales Forecast Comparison (GWh)



Graph 6.(1)-6
LG&E 2005 vs. 2002 IRP Peak Demand Forecast Comparison (MW)



Reason for Forecast Changes

The energy and demand forecasts in the 2005 IRP reflect the following changes from the previous filing:

- incorporation of the recent sales history in the forecasting models;
- changes in the characteristics of the company's load;
- changes in the curtailable/interruptible loads;
- updates to the weather assumptions;
- updates to the economic and demographic assumptions; and
- enhancements to the methodology used to prepare the forecast.

Recent Sales History

Combined Company

Recovery from the economic downturn beginning in 2001 was slower than expected, particularly in the LG&E service territory. The slower growth of sales continued into 2003 and was incorporated into the sales forecast.

On a Combined Company basis, weather-normalized actual sales (Table 6.(1)-4) came in lower than the 2002 IRP forecast in 2002, in 2003, and in 2004.

Table 6.(1)-4

Combined Company Energy Sales (GWh)

Variance to 2002 IRP Forecast

Year	2002 IRP	W/N Actuals	Difference	% Difference
2002	30,630	30,623	-7	0.0%
2003	31,710	31,518	-192	-0.6%
2004	32,780	32,278	-502	-1.5%

Kentucky Utilities

Table 6.(1)-5 compares the KU forecasted sales from the 2002 IRP to the weather-normalized calendar sales for the years 2002-2004. While KU's sales were above forecast in 2002, in both 2003 and 2004 sales came in below forecast.

Table 6.(1)-5
Kentucky Utilities Energy Sales (GWh)
Variance to 2002 IRP Forecast

Year	2002 IRP	W/N Actuals	Difference	% Difference
2002	19,097	19,187	91	0.5%
2003	19,866	19,803	-63	-0.3%
2004	20,669	20,534	-135	-0.7%

Louisville Gas & Electric

Table 6.(1)-6 compares the LG&E forecasted sales from the 2002 IRP to weather-normalized actual sales for the years 2002 through 2004. The weather-normalized actual sales were below the 2002 IRP forecast in 2002, in 2003, and in 2004.

Table 6.(1)-6
Louisville Gas & Electric Energy Sales (GWh)
Variance to 2002 IRP Forecast

Year	2002 IRP	W/N Actuals	Difference	% Difference
2002	11,533	11,436	-97	-0.8%
2003	11,844	11,715	-129	-1.1%
2004	12,111	11,744	-367	-3.0%

Changes in Load Characteristics

While the revision of the outlook for GDP growth resulted in the scaling back of energy forecasts, the key to the significant reduction in the projection of system peak demand is to be found in ongoing changes in the characteristics of the utilities' load.

These changes are complex, and relate to the composition of the market (load structure) and to the time-profile of demand (load shape); collectively, they find expression in the system load factor, which determines the relationship between energy sales over a given period and the peak load for that period. There is evidence that, over an extended period, the load factor of the combined utilities' system has been rising – particularly with respect to the load in the peak month. (See section on Changes in Methodology for further details.)

At the time of the 2002 IRP, the system annual peak demand was estimated by applying the load factor from a single "representative" peak month from a twenty-year reference period. In the current forecast, a ten-year average has been used to capture the upward trend in load factor that has been occurring in more recent history.

In adopting a higher load factor assumption, the current forecast addresses the over-prediction of peak demand in prior forecasts, and generates a projection of system peak which is more closely aligned with recent observations of system peak characteristics.

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 (Curtailable Service Rider, or "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 is added to the curtailed forecast.

After native load demand is determined, it is adjusted for the amount of load assumed to be curtailable or interruptible by either KU or LG&E based on existing contracts. Table 6.(1)-7 shows the changes in the assumed curtailable/interruptible loads from the 2002 IRP to the 2005 Forecast.

In the 2002 IRP, the KU CSR forecast called for 72 MW, which has decreased by 21 MW for a total CSR load of 51 MW in the 2005 IRP. Although one new customer has been added, the reduction in another's interruptible demand caused an overall decline. The LG&E interruptible forecast was 59 MW in the 2002 IRP but has been reduced to 49 MW in the 2005 IRP. This is due to the departure of some customers as well as to reductions in others.

Table 6.(1)-7

Changes in Curtailable/Interruptible Loads (MW)

	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**

Updates to Weather Assumptions

For both KU and LG&E, the most recent twenty-year average of heating degree days ("HDD") and cooling degree days ("CDD") is used to represent the weather conditions that are likely to be experienced on average over the forecast horizon. Twenty-year average weather data is considered to be more representative of recent trends compared to a thirty-year average. Weather data for Louisville and Lexington, Kentucky, as well as Bristol, Tennessee, are gathered from NOAA to represent the weather in the LG&E, KU and ODP service territories, respectively.

For the 2005 IRP forecast, normal weather for the KU service territory incorporates an average of 4,572 HDD as well as 1,240 CDD each year over the forecast period (on a 65-degree base). The normal Lexington weather assumption was 4,562 HDD and 1,224 CDD in the 2002 IRP.

Normal weather for the LG&E service territory is assumed to be 4,147 HDD and 1,553 CDD (also on a 65-degree base). Normal Louisville weather assumption in the 2002 IRP was 4,184 HDD and 1,527 CDD.

Updates to Economic and Demographic Assumptions

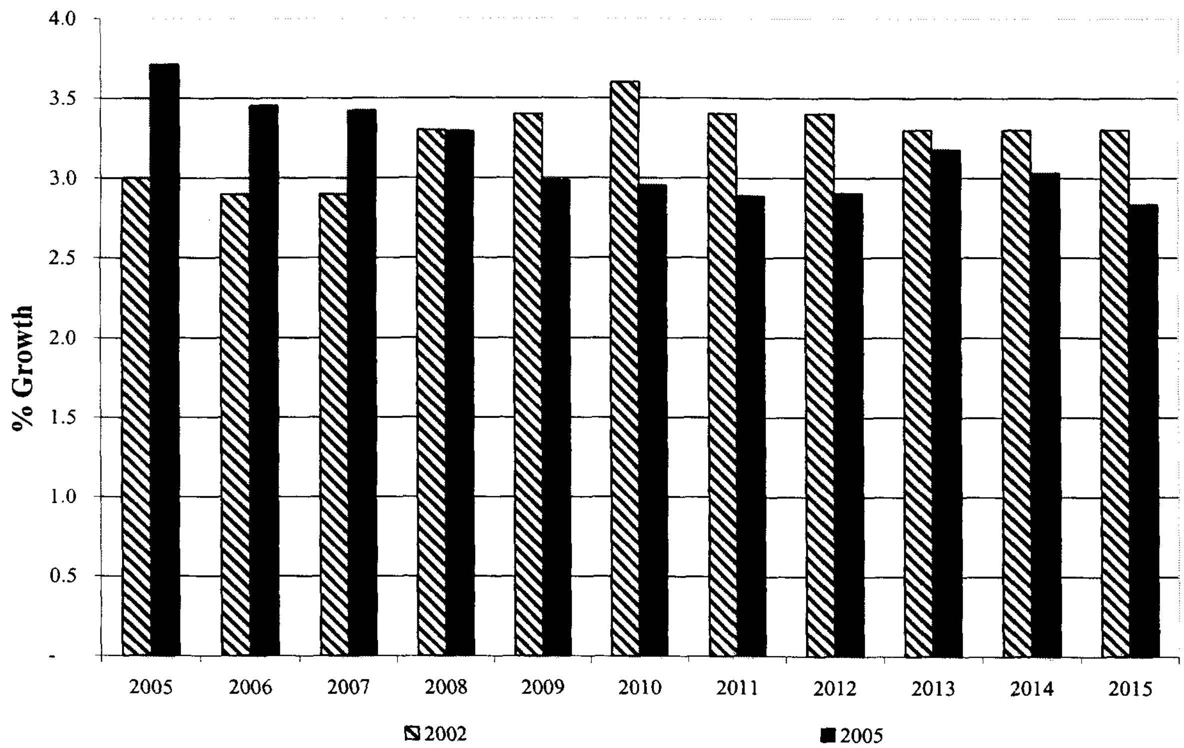
Since the 2002 IRP, the economic and demographic data used for energy forecasting has been updated and revised to reflect the most recent information and outlook. The national macroeconomic outlook used for the 2005 IRP forecast is attached as Appendix 4 in Volume II.

Service Territory Macroeconomic Forecast

Service-territory-level economic and demographic forecasts are developed using an employment-driven model ("STEM") in which forecasts of sector level value-added, employment, income, and population are generated for five regions that correspond to KU's and LG&E's service territories. The national forecast received from Global Insight provides the inputs for the Gatton Center for Business and Economic Research ("CBER") to generate a state forecast. This forecast in turn provides the inputs to the five regional models specific to geographic areas that influence economic activity in the utilities' service areas. These area forecasts are summed to create a total utility service territory forecast for each variable.

U.S. Gross Domestic Product ("GDP") is a primary driver in the STEM. Global Insight's projection of real GDP employed in the current forecast model is slightly below that used in the 2002 IRP forecast model. Over the 2005-2019 forecast horizon, the 2002 IRP forecast assumed an average annual growth rate in GDP of 3.3 percent, whereas the current forecast assumes an average annual GDP growth rate of 3.0 percent. This is displayed in Graph 6.(1)-7.

Graph 6.(1)-7
2005 vs. 2002 IRP Peak U.S. Real GDP Forecast Comparison



Demographic Forecasts

Demographic forecasts of population and households are critical to the accurate forecasting of Residential sales and indirectly contribute to the forecasting of Commercial sales through Residential customers' influence on Commercial customer growth. KU and LG&E utilize the population and household forecasts generated by the STEM model.

Estimates of number of households for the 1990-1999 period were increased for both the KU and LG&E service territories due to revisions in Bureau of Census reported numbers. For the latest forecast, KU service territory households are projected to rise at a 1.2 percent annual rate from 2005 to 2009, and a 1.1 percent average annual rate through the end of the forecast period.

Population estimates drive the household estimates in a given region. In the current energy forecast, LG&E service territory households are projected to rise at an 0.8 percent annual rate from 2005 to 2009 and remain at this rate through the end of the forecast period which is comparable with the 2002 IRP.

Changes in Methodology

There are two significant changes in the methodology employed in the forecast used for the 2005 IRP. These changes take into account, among other things, comments by the PSC in the December 2003 Staff Report on the 2002 IRP. Each will be discussed in turn.

LG&E Residential Sales Forecasting Methodology

For the 2005 IRP forecast, the LG&E Residential energy forecast employs a statistically-adjusted end-use ("SAE") model, the same methodology that is used to produce the KU and ODP Residential use-per-customer forecasts (2005 IRP). The SAE approach combines the advantages of econometric modeling – of the relationship of use-per-customer with weather, seasonal variables, and economic conditions – with key aspects of traditional end-use modeling relating to appliance saturation and efficiency trends. In the KU and LG&E models, monthly consumption per customer is related to heating use, cooling use, miscellaneous use, and seasonal binary variables.

Peak Demand Estimation Methodology

The process of estimating 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 against 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 a twenty-year average ratio of energy requirements in each month 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 by Management Application Consultants) that was used in the Companies' 2004 Rate Case. Average losses for KU (as a percentage of energy sent out) are estimated at 5.9% while LG&E losses are estimated at 5.3%.

Projection of Hourly Load (and Peak Demand)

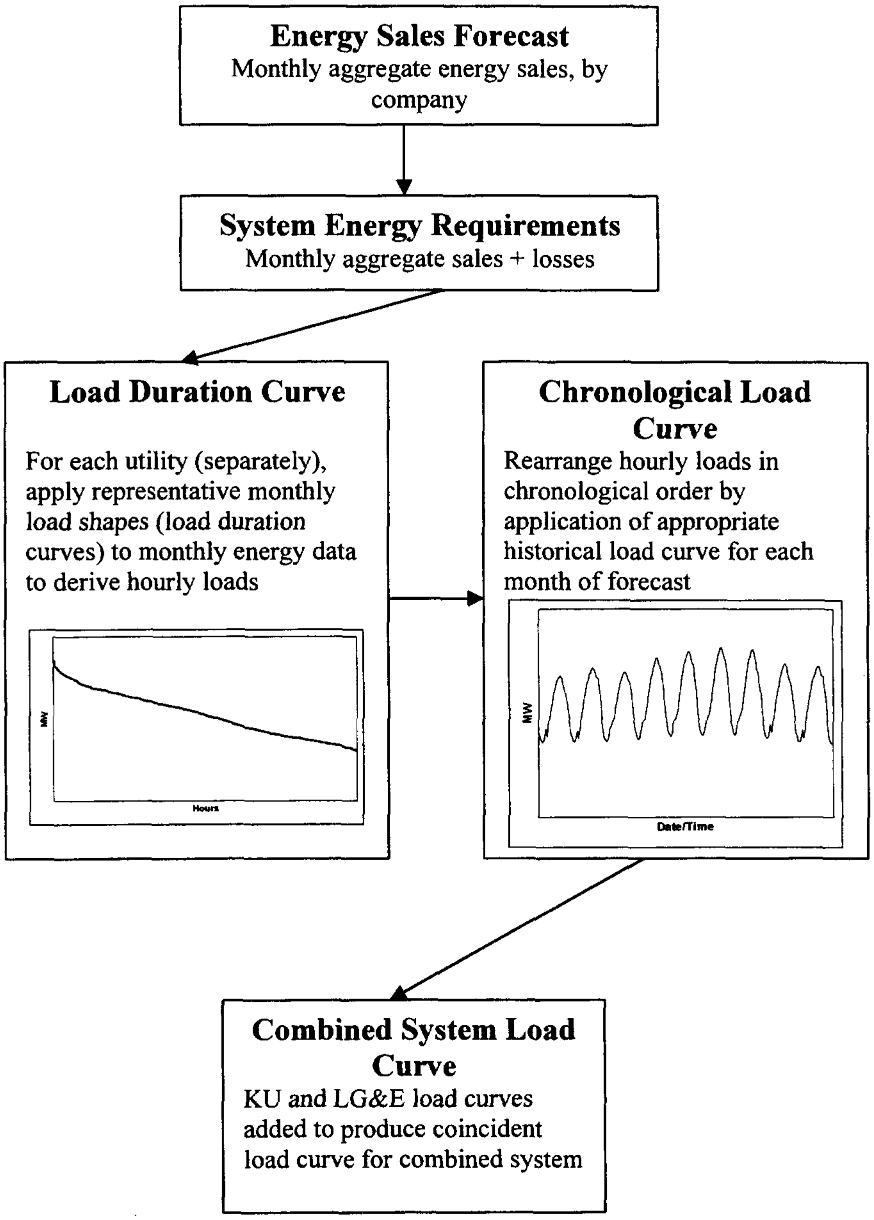
Figure-6.1 illustrates how the Companies' monthly energy forecast is converted into a chronological projection of hourly system loads which determines the Companies' annual peak demand. Since system peak demand is measured at the generator bus bar, the forecast of energy sales to customers is adjusted for transmission and distribution system losses. The forecasted monthly energy requirement (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 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 most significant impact of this change in methodology is the recognition of a higher load factor (and hence a lower peak) applying in the peak month. This result is consistent with historical trends (see Graphs 7.(4)(e)-1) and brings the current peak forecast more closely into alignment with recent observations on system peak. Application of a higher load factor is the principal reason that, over the 2005-2009 period, the 2005 IRP demand forecast is around 6.1 percent lower than the 2002 IRP whereas the projection of energy is only 3.2 percent lower.

[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.

Figure 6.1


Energy Sales Forecast
Monthly aggregate energy sales, by company
System Energy Requirements
Monthly aggregate sales + losses
Load Duration Curve
For each utility (separately), apply representative monthly load shapes (load duration curves) to monthly energy data to derive hourly loads
MW
Hours
Chronological Load Curve
Rearrange hourly loads in chronological order by application of appropriate historical load curve for each month of forecast
MW
Date/Time
Combined System Load Curve
KU and LG&E load curves added to produce coincident load curve for combined system

Demand-Side Management

The screening of DSM options was performed on a joint-company basis. The DSM objectives in the 2005 IRP are similar to the DSM objectives in previous filings, but the DSM alternatives considered did not include programs for industrial customers. After the development of the Companies' 2002 IRP filing, steps were taken to implement the Industrial Lighting Program which had been approved in the DSM filing (Case 2000-459). Industrial customers were provided an explanation of the proposed program and given the opportunity to 'opt out' of participation. Based on the results of this effort, this industrial program was not implemented. The Companies believe that the majority of their industrial customers do not wish to participate in Company-sponsored DSM programs, and are able to implement their own energy efficiency measures more cost effectively. The quantitative screening process utilizes EPRI's DSManager software, which the Companies used in their 2005 IRP.

For more details on the DSM screening see the report titled *Screening of Demand-Side Management (DSM) Options* (April 2005) in Volume III, Technical Appendix.

Reliability Criteria

In the Joint Companies 2002 IRP, the Companies used a combined target reserve margin of 14%, in the recommended range of 13% to 15%. In the current assessment and acquisition study, the Companies continued to use a combined target reserve margin of 14%, in the recommended range of 12% to 14%. A discussion of the reliability criteria is found in the report titled *2005 Analysis of Reserve Margin Planning Criterion* (January 2005) contained in Volume III, Technical Appendix.

Wholesale Power Market

In the years leading up to 2000, the wholesale power market had undergone significant change with the Energy Policy Act of 1992, Federal Energy Regulatory Commission ("FERC") Orders 888 and 889 in April of 1996, and in recent years the establishment of Independent System Operator ("ISOs") and Regional Transmission Organization ("RTOs") pursuant to FERC Order 2000. Since that time, ISOs and RTOs have developed and implemented wholesale energy markets based on locational marginal pricing ("LMP"). The MISO Day 2 Markets ("Day 2") which establish Day Ahead and Real-Time energy markets based on LMPs, will impact the nature of wholesale power market operations in the Midwest. Also in recent years, the influences of supply and demand in both the real-time and long-term energy market and the fuels market (coal, natural gas, and oil) have notably affected prices in the wholesale power market. In the electricity marketplace of the Midwest, the physical forward commodity market activity has declined, allowing for price discovery for the standard market product (for example 50MWs delivered Monday through Friday for 16 peak hours per day – 5X16, Into Cinergy) on a limited short-term basis (next day through the next 24 months). However the traditional Request For Proposal ("RFP") to purchase power serves well to determine market prices for unique products that emulate new generation capacity.

The unprecedented price volatility that started in the Midwest market in June of 1998 has not been repeated due to the increase in supply, e.g. new peaking capacity installed in the region in the past few years. Next-day peak power prices which reached $239/MWh in 1997 and then rose as high as $7,500/MWh in 1998 have steadily dropped to $2000/MWh in 1999, $200/MWh in 2000, $150/MWh in 2001, and only $60/MWh in 2002. However, trends in the last two years have contributed to an increase in next day prices in 2003 and 2004 to as high as

$129/MWh. These market price trends (which are difficult to predict) in addition to other industry trends referenced below, are significant relative to the Companies' need to address native load growth and expansion in a cost effective manner. A review of these industry trends and their significance is discussed below.

First, recent upward pressure in fuel prices, particularly natural gas, has caused power prices in 2003 and 2004 to increase. The notable decline in power prices in 2002 confirmed that the marketplace responded to high prices and price volatility in earlier years by installing more supply in the form of peaking capacity utilizing relatively low priced natural gas. However, recent upward pressure in natural gas prices, from $2.00/Mmbtu in 2002 up to $10.00/Mmbtu in 2003, has caused even the hourly market in the Midwest to consistently fluctuate around the incremental cost of combined cycle generation and peaking generation, up to $150.00/MWh in 2003 and $122.00/MWh in 2004.

Second, even though summer prices have apparently been effectively capped at the incremental production cost of gas peaking generation, there has developed increasing dependence on gas-fired capacity throughout peak periods of each peak day, Monday through Friday. During peak days the hourly market price quickly rises to the incremental production cost of gas-fired units before noon and often transacts at these prices until 10:00 pm. This growing dependency on gas-fired capacity in the past two years has raised the overall production cost of electricity in the Midwest.

Third, with the fall in market prices from the highs in 1998 and 1999 and recent market prices capped at the incremental production cost of gas-fired generation, many of the build plans by merchant Independent Power Producers ("IPPs") for new peaking generation were scaled back or abandoned. This sudden slowing and now halt of the building of merchant peaking generation should influence how long this period of peak price predictability will exist in the Midwest. The wholesale commodity forward market may be reflecting this trend with on-peak prices increasing 5% from January to December 2004.

Fourth, the demise of several leading power marketing companies known for their entrepreneurial investments in new generation along with the uncertainty of evolving power markets in the Midwest has created an environment unfavorable to further IPP investment in new generation at this time. This lack of viable investors in speculative development of new generation will diminish competition in new generation. Thus future wholesale market price trends for power will be influenced most likely toward higher prices by the lack of parties competing to install merchant power plants.

Fifth, with increasing energy usage there is concern that the floor price for off-peak energy in the Midwest market could increase, as noted in 1999, 2000, and 2001 on the west coast. This potential increase in the floor price of off-peak energy to serve load at nights and during weekends can be attributed to two factors: first, the increased dependence on vintage 1950's and 1960's coal generation plants with high incremental cost from both the inefficiencies of burning coal and the incremental environmental compliance cost; second, the increased dependence on combined-cycle gas turbines. Data in years prior to 2003 have shown that off-peak market prices are associated with the incremental production cost from baseload low-cost coal generation plants from the late 70's and early 80's. This dependence on higher incremental cost plants (vintage 1950's and 1960's coal plant and combined cycle plants) shows an increase from an average off-peak energy price of $18/MWh in 2003 to $23/MWh in 2004. This trend will also contribute to the overall increase in the cost of power in the Midwest.

Sixth, the fundamental changes in the electric industry could result in an increase in the transmission congestion and loss components of energy prices particularly to serve native load customers in Kentucky. These fundamental changes include the following: (a) prior to 1990, transmission served local load from local generation; (b) while from 1990 through 2004, transmission served load in areas of high cost generation through long distance wholesale transactions; and (c) the expected upcoming sharing of the costs of transmission and generation to serve all customers at the lowest possible cost through MISO Day 2 markets. Finally, the ever-increasing public awareness and concern over the quality of the environment will further support environmental legislation, which could impose even stricter environmental limits on electrical generation. Currently, the industry faces the capitalization and operational cost of Sulfur Dioxide Removal Systems and nitrogen oxide abatement through the installation of Selective Catalytic Reduction and other strategies, as covered in detail in the *Clean Air Act Compliance* portion of Section 8.(5)(b). In the future the industry should expect more restrictions and more costly abatement systems. Increasing electric energy prices will directly reflect these likely increasing environmental costs. Further environmental impacts on electric energy prices will be the price volatility in the Emission Allowances commodity market.

As in the past, the Companies have relied on RFP responses to determine the prices for purchased power in submitting an Application for a Certificate of Public Convenience and Necessity ("CCN") for resource acquisitions to address native load needs. The Companies expect to continue to issue RFPs for purchased power in the future to ascertain the availability and price of long-term supply and will do so prior to considering the installation of any new generating resources identified in the Plan outlined in Table 5.(4). The Companies will also continue to utilize their participation in the wholesale power market as a primary means of collecting data on purchased power availability and price for limited term supply of several years. The advancement of information technology that supports the marketplace continues to improve the overall efficiency of the current wholesale energy commodity market, which makes market prices more readily available on a real-time basis. This current wholesale energy commodity market in the Midwest is expected to change significantly in 2005 with the emergence of the MISO Day 2 markets.

This report is a snapshot in time of an ongoing resource planning process. The supply-side cost data used in this analysis is the best data available to the Companies at this time. The availability of physical capacity resources is subject to market trends of supply and demand, much like purchased power prices. Even though the availability and price of generation capacity will continue to fluctuate as the wholesale power market continues to mature and evolve, the Companies will continue to seek out the most cost effective plans for providing reliable low cost electrical energy to the native load customers in both the short and long terms.

Rehabilitation of Ohio Falls

Ohio Falls is a run-of-river station that operates in conjunction with the United States Army Corps of Engineers ("USACE"), which owns and is responsible for the operation of the McAlpine Locks and Dam. The Ohio Falls station is located in the middle of a 1,400-acre National Wildlife Conservation Area ("NWCA") that also is under the administration of the USACE. The USACE has the responsibility for operation of the dam and consequently manages the flows for navigation, irrigation, flood control, recreation, and the preservation of fish and wildlife. LG&E operates the power plant to generate electricity only when water flow is available, as determined by the USACE, thereby relegating power generation to a subordinate role.

The 2002 IRP identified that LG&E had filed the formal "Notice of Intent" to relicense the facility with the 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 3, 2005, LG&E officially requested the new license from FERC have a term of 40 years.

Ohio Falls has been in service since the 1920's. A rehabilitation project implemented in three phases over a number of years began in 2001 with portions of Phase 1 and Phase 2 performed simultaneously. Phase 1, which was completed in the fall of 2002, included new automated controls allowing remote unit operation in an economical and efficient manner. Phase 2 involved the design and installation of modern trash removal systems, minimizing the labor required and the volume of river debris removal. This phase actually began with clearing the submerged debris and sedimentation from the upstream headworks, facilitating the installation of the new trash control and removal mechanisms. The new mechanisms allow the trash removal for all eight units to be done in one day compared with the one or two units per day with the previous design and staff. The inlet channel silt and debris excavation was completed in 2001. Trash removal equipment was installed in 2004, completing Phase 2 of the rehabilitation.

Phase 3 entails the most significant scope of work to date, the rehabilitation of the turbine/generator units. A report from Voith Siemens Hydro ("VSH") in June 2002 and again in 2003, provided updates to their previous engineering study assessing the condition of the existing eight hydro units and analyzing what would be necessary to upgrade or rehabilitate the units. In May 2003, model testing of a newly designed turbine runner was performed by VSH to demonstrate that all performance guarantees can be met or exceeded. These studies were evaluated by the Companies and a recommendation to rehabilitate all eight hydro units was developed. To validate the work provided by VSH, RMD Consult (a subsidiary of E.ON Engineering) reviewed the VSH 2003 report.

RMD Consult was contracted to review the VSH proposal in detail. An RMD team consisting of one mechanical, one electrical and one civil engineer visited the site and assessed the condition of both the plant and the equipment. The RMD work verified that the scope of work and costs proposed by VSH are reasonable.

Without Phase 3 of the rehabilitation, the units at Ohio Falls will likely fail to the point beyond repair and generation would be greatly reduced or lost completely. Phase 3 of the rehabilitation would increase the expected capacity of the facility from the current planned value at the time of summer peak of 48 MW to 64 MW and increase the energy from the five-year average production of 250 GWh to 438 GWh.

After completing the first unit rehab, each of the remaining seven units will be reviewed and completed successively over the following seven years comprising an investment of up to $75.7M (nominal).

Retirement of Green River Units 1 and 2

Green River Units 1 and 2 were completed in 1950 and provided 25 megawatts of gross generation each. In 2003, these units were 53 years old. Having operated past their design lives, these units ran a greater risk of catastrophic failure than other units. Based on economic evaluations, Green River Units 1 and 2 were operationally retired December 31, 2003 for economic reasons.

The challenges facing the units, the necessary actions to remedy those situations as well as their associated cost were explained in detail in the evaluation titled *Phase II Evaluation of the Economic Viability of Green River Units 1 and 2,* which was provided in Case No. 2003-00434, Response 15.b(1) in the Second Data request of the Commission Staff. Subsequently, as stated in detail in Response 4 of the Post-Hearing Data Responses to Information requested by the Commission Staff and the Attorney General in Case No. 2003-00434, the retirement of Green River Units 1 and 2 was booked on March 31, 2004 and Account 101 (Electric Plant in Service) was reduced by the value of the generation units at that time.

MISO

In 1996, several Midwestern utilities, including the Companies, formed an Independent System Operator ("ISO") for the Midwest region of the United States. This ISO is known as the Midwest Independent Transmission System Operator Inc. ("MISO"). MISO became the nation's first Regional Transmission Organization ("RTO") approved by the FERC on December 19, 2001. MISO is based in Carmel, Indiana, and is responsible for monitoring the electric transmission system that delivers power from generating plants to wholesale power customers. MISO's stated role is to ensure equal access to the transmission system and to maintain or improve electric system reliability in the Midwest.

MISO Day 2 Markets

As mentioned in the Wholesale Power Market section, MISO Day 2 Markets, i.e. Day Ahead and Real-Time energy markets with LMPs, will impact the very nature of the wholesale power market in the Midwest. The expected costs and benefits associated with the Companies' membership in MISO are the subject of a Commission investigation in Case No. 2003-00266 and are not explicitly incorporated as a significant change to the 2005 IRP relative to the 2002 IRP due to the on-going nature of that proceeding.

Exit from MISO

In December 2004, the Companies notified MISO of their intent to withdraw from MISO at the end of 2005. The Companies' continued membership is also the subject of an ongoing Commission investigation in Case No. 2003-00266. The outcome of this proceeding and any subsequent proceedings related to the Companies' membership in MISO may ultimately impact the analyses included in the 2005 IRP. It is not possible to detail those potential impacts at this time.

Lock 7

Since the 2002 IRP, KU has been evaluating alternatives pertaining to the rehabilitation or disposition of the Lock No. 7 Project ("Lock 7"), 2-MW run-of-river hydroelectric power plant constructed in 1928.

On April 1, 2004, KU issued an Initial Consultation Document to present its general plans to surrender the FERC license for the Lock No. 7 Project ("Lock 7") and to remove all plant structures above the waterline. On May 13, 2004, KU held a public meeting to discuss the ICD. Attendees included agency and third-party representatives as well as interested members of the general public ("stakeholders"). The stakeholders had a number of questions and expressed the preference that Lock 7 not be decommissioned. A number of respondents expressed their concern regarding the removal of a renewable energy source and encouraged KU to find a way to turn the project over to another owner. KU received a number of letters from stakeholders who expressed similar comments.

After the public meeting, KU considered the weight of the public comments and notified interested parties that they would put their surrender application on hold, if that was acceptable to FERC, to work in good faith with key parties to come to an acceptable agreement to transfer Lock 7 to a new owner.

On December 30, 2004, KU signed a letter of intent with a third party for the purpose of having that party (the "Buyer") acquire Lock 7 from KU. At this time, KU is working with the Buyer to develop detailed terms and conditions for such a transaction prior to initiating the necessary proceedings before the applicable federal and state agencies, as appropriate, for the Buyer to purchase Lock 7 and for KU to transfer the FERC license for Lock 7 to the Buyer. This process and the attendant proceedings are expected to continue through 2005.

As in the 1999 IRP and the 2002 IRP, the capacity of Lock 7 was not included in the reserve margin analyses in the 2005 IRP.