Table 8.(3)(b)12

Kentucky Utilities Company / Louisville Gas & Electric Company

Actual and Projected Cost and Operating Information for

Greenfield CT 6

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	Capacity Factor (%)															0.5	0.1
	Availability Factor (%)															91.3	91.3
b	Average Heat Rate (Btu/kWh)															12,132	12,145
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 Coal 1

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**																45.5
	Availability Factor (%)																89.5
b	**Average Heat Rate (Btu/kWh)**																9,396
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

Dix Dam 1,2,3

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	44.9	27.2	27.2	27.2	27.1	27.2	27.2	27.2	27.1	27.2	27.2	27.2	27.1	27.2	27.2	27.2
b	**Average Heat Rate (Btu/kWh)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none
c	**Cost of Fuel ($/MBTU)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none

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

Ohio Falls 1-8

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
a	**Capacity Factor (%)**	50.9	92.1	89.4	84.9	81.3	86.6	86.4	85.6	85.0	78.6	78.6	78.6	78.4	78.6	78.6	78.6
b	**Average Heat Rate (Btu/kWh)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none
c	**Cost of Fuel ($/MBTU)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none

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

WV Hydro PPA

		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	69.7	69.7	69.5	69.7	69.7	69.7
b	**Average Heat Rate (Btu/kWh)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none
c	**Cost of Fuel ($/MBTU)**	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none	none

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

Table 8.(3)(b)12(d),(f)

Kentucky Utilities Company / Louisville Gas & Electric

Capital Costs and Escalation Factors
(In 2004 Dollars)

	Trimble County Coal	Greenfield CT	Unphased Combined Cycle	Greenfield Coal
Capital Costs ($/kW)	[redacted]			
Total Capital Costs ($x1000)				
Capital Escalation Factor (%)	1.9	2.0	2.0	1.9
Variable O&M Escalation Factor (%)	2.0	2.0	2.0	2.0
Fixed O&M Escalation Factor (%)	2.0	2.0	2.0	2.0

Notes:

Capital Cost $/kW based on summer rating.

Fixed and Variable Escalation Factors also apply to existing units as well.

Trimble County Coal Unit Total Capital Costs is 75% of expected project total.

Table 8.(3)(b)12(e)

Kentucky Utilities Company / Louisville Gas & Electric Company

Variable and Fixed Operating and Maintenance Costs ($000)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Existing units*	164,064	[redacted]														
Trimble County 2 (75%)		[redacted]														
Greenfield CT 1		[redacted]														
Greenfield CT 2		[redacted]														
Greenfield CT 3		[redacted]														
Greenfield CT 4		[redacted]														
Greenfield CT 5		[redacted]														
Greenfield CT 6		[redacted]														

* Data not available by individual units

Notes: 2004 numbers are actuals.

An annual gas reservation expense is in included in the Fixed O&M of CTs and Combined Cycle units.

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Table 8.(3)(b)12(g) - 1

Kentucky Utilities Company / Louisville Gas & Electric Company

Total Electricity Production Costs (cents/kWh)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Existing units*	1.99	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Trimble County 2 (75%)		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenfield CT 1		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenfield CT 2		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenfield CT 3		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenfield CT 4		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenfield CT 5		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]
Greenfield CT 6		[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]	[redacted]

* Data not available by individual units

Notes: 2004 numbers are actuals.

Total Electric Production Costs includes Fixed O&M, Variable O&M, Fuel and Gas Transportation reservation.

Table 8.(3)(b)12(g) - 2

Kentucky Utilities Company / Louisville Gas & Electric Company

Average Variable Production Costs (cents/kWh)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Existing units*	1.56	[redacted]														
Trimble County 2 (75%)																
Greenfield CT 1																
Greenfield CT 2																
Greenfield CT 3																
Greenfield CT 4																
Greenfield CT 5																
Greenfield CT 6																

* Data not available by individual units

Notes: 2004 numbers are actuals.

Average Variable Production Costs includes Variable O&M and Fuel.

8.(3)(c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.

The requested information can be found in the Table 8.(3)(c) on the following page.

Table 8.(3)(c)

Kentucky Utilities Company / Louisville Gas & Electric Company

Description of Transactions for Purchases, Sales or Exchanges of Electricity

Purchases (GWh)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OMU	1,586	1,808	1,799	1,798	1,526	1,780	1,776	1,776	1,775	1,767	1,763	1,485	1,761	1,748	1,750	1,744
EEI	1,648	1,450	1,451	1,451	1,456	1,451	1,451	1,451	1,456	1,451	1,451	1,451	1,456	1,451	1,451	1,451
OVEC	1,371	1,259	1,202	1,170	1,173	1,172	1,145	1,134	1,149	1,150	1,139	1,150	1,157	1,159	1,163	1,163
Other	183	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Sales (GWh)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OMU	10	4	6	16	9	5	5	5	8	8	15	10	10	9	9	6
OTHER	4,297	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Notes: 2004 numbers are actuals.

8.(3)(d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.

The requested information can be found in Table 8.(3)(d) on the following page.

Table 8.(3)(d)

Kentucky Utilities Company / Louisville Gas & Electric Company

Non-Utility Sources of Generation

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Generating Capacity (MW)	None	None	None	None	None	None	None	None	None	None	181	181	181	181	181	181
Energy (GWh)	None	None	None	None	None	None	None	None	None	None	1,160	1,160	1,160	1,160	1,160	1,160

Notes: 2004 numbers are actuals.
All data above is related to the WV Hydro PPA
Capacity is at summer peak

8.(3)(e) For each existing and new conservation and load management or other demand-side programs included in the plan:

8.(3)(e)(1) Targeted classes and end-uses;

Existing Programs

KU and LG&E Rate Schedule CSR1, CSR2, and CSR3 (Curtailable Service Riders) – This program is aimed at decreasing demand in the commercial and industrial sectors during system peak periods. In return for a rate incentive, participating customers agree to reduce demand to a predetermined level upon the respective Company's request.

KU Rate Schedules LCI-TOD & LMP-TOD (Time-of-Day Rates) – This program is targeted at the commercial and industrial sectors. A differential in on- and off-peak demand charges is used to encourage large customers to shift part of their demand from system peak periods to off-peak periods.

LG&E Rate Schedule LC-TOD, LP-TOD, and LI-TOD (Time-of-Day Rates) – This program is targeted at the commercial and industrial sectors. A differential in on- and off-peak demand charges is used to encourage large customers to shift part of their demand from system peaks to off-peak periods.

KU and LG&E Rate Schedule NMS (Net Metering Service) – This pilot program allows customers with a solar, wind, or hydro generation to offset their energy bill when their generator is generating more than the customer is consuming. The pilot program was initiated March 24, 2002 via Commission Order in Cases 2001-00304 and 2001-00303 for KU and LG&E, respectively. The Companies have since filed for the program to become a permanent rate in compliance with KRS 278.465 through KRS 278.468.

KU and LG&E Rate Schedule LRI (Load Reduction Incentive) – This pilot program is aimed at decreasing demand during peak periods. Customers with standby generators of a minimum 500 kW receive a rate incentive by agreeing to carry that load upon the respective Company's request. The three year pilot program was initiated August 1, 2000. KU and LG&E have since filed for a three-year program extension which has been approved.

KU and LG&E Rate Schedule STOD (Small Time-of-Day Service) – This pilot program is aimed at decreasing demand in small commercial classes. A differential in on- and off-peak energy charges is used to encourage customers to shift part of their demand from system peak periods to off-peak periods. The pilot program was initiated October 6, 2004 via Commission Order in Cases 2001-00434 and 2001-00433 for KU and LG&E respectively.

Residential Energy Audits – This program targets customers who own or occupy single-family homes, apartments or condominiums. It is designed to provide customers with an on-site home energy audit that will provide opportunities for improved energy efficiency. Also below market financing is available for customers interested in purchasing Energy Star appliances.

Commercial Energy Audits - This program is offered to all commercial class customers in the LG&E service area and all KU General Service commercial customers. The objective of this program is to identify energy efficiency opportunities for commercial class customers and assist them in the implementation of these identified energy efficiency opportunities. Also below market financing is available for customers interested in purchasing Energy Star appliances.

Demand Conservation Program – This program cycles residential and commercial central air conditioning units, water heaters, and residential pool pumps of both KU and LG&E customers. It is designed to provide customers with an incentive to allow the Companies to interrupt service to their central air conditioners, water heaters, and/or pool pumps at those peak demand periods when the Companies need additional resources to meet customer demand.

WeCare Program – This program helps those customers that are less fortunate by weatherizing their home which reduces their energy bills. This program is available to LIHEAP eligible customers in the Louisville and Lexington metropolitan areas.

New Programs

Setback Thermostat Program – This program is a compliment to our existing Demand Conservation program, for residential and commercial customers. The Setback Thermostat program can either change the set point on the thermostat or duty cycle the air conditioner, as does the Demand Conservation Program device, at those peak demand periods when the Companies need additional resources to meet customer demand, and also allow the customer to reduce heating and cooling costs year round. Customers would be provided the thermostat at no cost, but would not receive the bill credit, as do customers in the existing Demand Conservation program.

Smart Thermostat (TOU rate) - This is a sophisticated load management and Time of Use ("TOU") rate program for residential and commercial customers. The TOU rate will be a 3-tier TOU rate similar to those existing at other utilities, but with a fourth "real time" component. Customers would set heating and cooling temperatures and turn large loads such as water heaters off or on, based on the price of electricity, reducing usage at those peak demand periods when the Companies need additional resources to meet customer demand.

A/C Tune-Up Program - This program would provide commercial customers an analysis of existing commercial air conditioning systems and discounted corrective action when necessary to correct the refrigerant charge and air flow across the evaporator coil.

Energy Efficient Indoor Lighting Program - This program would piggyback on the existing Residential Conservation program and provide residential customers with a wide selection of compact fluorescent bulbs at below retail pricing.

Polarized Refrigerant Oxidant Agent Program ("PROA") - This program would provide an analysis of existing commercial customer's air conditioner and heat pump systems and incentives for customers to install PROA where necessary, reducing cooling costs and heating costs.

8.(3)(e)(2) Expected duration of the program;

The existing DSM programs are expected to serve customers through the year 2007 per the KPSC Order in Case Number 2000-459. However, the Companies will continuously review and evaluate the existing and proposed DSM programs with the intention of making a new DSM filing during 2005.

8.(3)(e)(3) Projected energy changes by season, and summer and winter peak demand changes;

Load changes for the existing rate programs, excluding the LG&E Rider for Interruptible Service, have not been estimated, as they are currently captured in the Load Forecast. Table 8.(3)(e)(3) below summarizes the annual energy impact and the summer and winter peak demand of the LG&E interruptible rate and the future programs.

Table 8.(3)(e)(3)

Kentucky Utilities Company / Louisville Gas & Electric Company

Demand Side Management Energy and Demand Impacts

Energy Reduction (GWh)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Interruptible/CSR	NA	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Setback Thermostats	0.0	2.9	6.8	10.6	14.5	18.4	22.2	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1	26.1
Smart Thermostats	0.0	0.2	1.2	3.1	6.0	9.2	12.7	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2	16.2
A/C Tune-up	0.0	0.2	0.5	0.9	1.5	2.3	3.0	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8	3.8
Energy Efficient Indoor Lighting	0.0	0.6	1.2	1.7	2.3	2.9	3.5	4.1	3.5	2.9	2.3	1.7	1.2	0.6	0.0	0.0
Polarized Refrigerant Oxidant	0.0	0.1	0.4	1.1	2.1	3.4	4.6	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9	5.9

Summer Peak Demand Reduction (MW)

	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Interruptible/CSR	NA	100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
Setback Thermostats	0.0	1.6	3.7	5.7	7.8	9.9	12.0	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1	14.1
Smart Thermostats	0.0	0.1	0.4	1.1	2.2	3.3	4.6	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8	5.8
A/C Tune-up	0.0	0.1	0.4	0.8	1.3	2.0	2.6	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3	3.3
Energy Efficient Indoor Lighting	0.0	0.1	0.1	0.2	0.2	0.3	0.3	0.4	0.3	0.3	0.2	0.2	0.1	0.1	0.0	0.0
Polarized Refrigerant Oxidant	0.0	0.1	0.3	1.0	1.9	3.0	4.1	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2	5.2

Winter Peak Demand Reduction (MW)

	04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
Interruptible/CSR	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
Setback Thermostats	0.0	1.9	4.3	6.8	9.3	11.7	14.2	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7	16.7
Smart Thermostats	0.0	0.2	1.0	2.7	5.2	8.1	11.1	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2	14.2
A/C Tune-up	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
Energy Efficient Indoor Lighting	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
Polarized Refrigerant Oxidant	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

8.(3)(e)(4) Projected cost, including any incentive payments and program administrative costs; and

The projected cost for the existing and proposed DSM programs are as shown below in Table 8.(3)(e)-4. The costs of the five new programs are reported in detail on Exhibit DSM-8 of the report titled *Screening of Demand-Side Management (DSM) Options* (December 2004) contained in Volume III, Technical Appendix.

Table 8.(3)(e)-4
Existing and Proposed DSM Program Costs ($)

Existing Program Cost	2005	2006	2007	2008	2009	2010	2011
Residential Conservation	385,556	387,023	390,383				
Residential Load Management	6,517,711	6,723,506	6,568,012				
Res. Low Income Weatherization	1,649,049	1,707,982	1,769,038				
Commercial Conservation	832,619	835,861	839,221				
Commercial Load Management	122,780	116,404	111,540				
Program Development & Admin.	92,647	94,884	97,202				

Proposed Program Costs	2005	2006	2007	2008	2009	2010	2011
Setback Thermostat	728,250	948,928	951,837	985,506	989,965	1,010,243	1,046,374
Smart Thermostat (TOU)	180,000	317,210	473,456	674,263	767,963	831,696	887,988
A/C Tune-Up	83,600	119,008	145,752	185,892	223,489	227,764	234,167
Energy Efficient Indoor Lighting	59,000	43,729	44,480	45,253	46,050	46,870	52,715
Polarized Refrigerant Oxidant Agent	95,100	92,248	206,550	263,648	331,188	338,359	362,805

8.(3)(e)(5) Projected cost savings, including savings in utility's generation, transmission and distribution costs.

The difference between the PVRR with and without the existing and new DSM programs is $23.4 million, in 2005 dollars.

8.(4) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:

The Companies' resource planning process considers the economics and practicality of available options to meet customer needs at the lowest practical cost. A study was completed to determine an optimal target reserve margin criterion to be used by the Companies. The results of this study suggested an optimal reserve margin in the range of 12% to 14%. In the development of the optimal IRP, the Companies retained a reserve margin target of 14%. Details of this study entitled *2005 Analysis of Reserve Margin Planning Criterion* (January 2005) can be found in Volume III, Technical Appendix. This section provides information associated with the recommended IRP resulting from the Companies' resource planning process outlined in Section 8.(5). The plan resulting from the Companies' optimal IRP analysis is shown in Table 8.(4) and is detailed in a report titled, *2005 Optimal Expansion Plan Analysis* (January 2005) in Volume III, Technical Appendix. The in-service years for the units shown assume the Companies' Base Load Forecast.

Table 8.(4)
Recommended 2005 Integrated Resource Plan

Year	Resource
2005	1.9 MW New DSM Initiatives
2006	4.9 MW New DSM Initiatives (cumulative totals)
2007	8.8 MW New DSM Initiatives (cumulative totals)
2008	13.4 MW New DSM Initiatives (cumulative totals)
2009	18.5 MW New DSM Initiatives (cumulative totals)
2010	549 MW (75% of 732 MW) Trimble County Unit 2 Supercritical Coal 23.7 MW New DSM Initiatives (cumulative totals)
2011	28.8 MW New DSM Initiatives (cumulative totals)
2012	
2013	148 MW Greenfield CT Unit 1
2014	WV Hydro Purchase Power Agreement
2015	148 MW Greenfield CT Unit 2 148 MW Greenfield CT Unit 3
2016	148 MW Greenfield CT Unit 4
2017	148 MW Greenfield CT Unit 5
2018	148 MW Greenfield CT Unit 6
2019	750 MW Greenfield Supercritical Coal Unit

Note: Unit Ratings are Proposed Summer Net Ratings

8.(4)(a) On total resource capacity available at the winter and summer peak:

1. **Forecast peak load;**
2. **Capacity from existing resources before consideration of retirements;**
3. **Capacity from planned utility-owned generating plant capacity additions;**
4. **Capacity available from firm purchases from other utilities;**
5. **Capacity available from firm purchases from nonutility sources of generation;**
6. **Reductions or increases in peak demand from new conservation and load management or other demand-side programs;**
7. **Committed capacity sales to wholesale customers coincident with peak;**
8. **Planned retirements;**
9. **Reserve requirements;**
10. **Capacity excess or deficit;**
11. **Capacity or reserve margin.**

The requested information can be found in Table 8.(4)(a)-1 and Table 8.(4)(a)-2 on the following pages.

Table 8.(4)(a)-1

Kentucky Utilities Company / Louisville Gas & Electric Company
Resource Assesment and Acquisition Plan
Resource Capacity Available (MW)

At Summer Peak

		2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
1	**Forecasted Peak Load**	6223	6796	6911	7051	7225	7372	7482	7655	7762	7959	8093	8259	8392	8530	8687	8894
	Existing Peak Reductions																
6	**Interruptible**		100	100	100	100	100	100	100	100	100	100	100	100	100	100	100
	Existing DSM		73	95	114	122	122	122	122	122	122	122	122	122	122	122	122
	Planned Peak Reduction (DSM)		2	5	9	13	19	24	29	29	29	29	29	29	29	28	28
	Total Demand	6223	6621	6711	6828	6989	7131	7236	7404	7511	7708	7842	8008	8141	8279	8436	8643
	Capacity From:																
2	**Existing Resources**	7610	7588	7592	7581	7570	7536	7539	8091	8095	8107	8255	8255	8551	8699	8847	8995
3	**Planned Resources**	0	0	0	0	0	0	549	0	0	148	0	296	148	148	148	736
4	**Firm Purchases:**																
	EEI (MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	OMU (MW)	187	196	195	193	193	192	191	190	189	188	187	186	185	184	183	182
	OVEC (MW)	209	209	179	179	179	179	179	179	179	179	179	179	179	179	179	179
5	**Firm Purchases Non-Utility**	0	0	0	0	0	0	0	0	0	0	181	181	181	181	181	181
7	**Committed Capacity Sales**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	**Planned Retirements**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Supply	8206	8192	8165	8153	8141	8107	8658	8660	8663	8822	9002	9297	9444	9591	9738	10473
9	**Reserve Requirements**	871	927	940	956	978	998	1013	1037	1052	1079	1098	1121	1140	1159	1181	1210
10	**Excess (Deficit)**	1112	644	514	369	174	-23	409	220	100	34	62	168	163	152	120	619
11	**Reserve Margin (%)**	31.9%	23.7%	21.7%	19.4%	16.5%	13.7%	19.6%	17.0%	15.3%	14.4%	14.8%	16.1%	16.0%	15.8%	15.4%	21.2%

Note: 2004 summer peak is actual, Capacity and peak reduction are planned values.
Note: 2005 Capacity Resources were actual arrangements based upon previous peak forecast

Table 8.(4)(a)-2

Kentucky Utilities Company / Louisville Gas & Electric Company
Resource Assesment and Acquisition Plan
Resource Capacity Available (MW)

At Winter Peak

		04/05	05/06	06/07	07/08	08/09	09/10	10/11	11/12	12/13	13/14	14/15	15/16	16/17	17/18	18/19	19/20
1	**Forecasted Peak Load**	5829	5792	5934	6012	6180	6261	6426	6538	6612	6806	6928	7010	7172	7325	7393	7607
	Existing Peak Reductions																
	Interruptible		38	38	38	38	38	38	38	38	38	38	38	38	38	38	38
6	**Existing DSM**		3	4	5	5	5	5	5	5	5	5	5	5	5	5	3
	Planned Peak Reduction (DSM)		2	5	10	15	20	25	31	31	31	31	31	31	31	31	31
	Total Demand	5829	5749	5887	5959	6122	6198	6358	6464	6538	6732	6854	6936	7098	7251	7319	7536
	Capacity From:																
2	**Existing Resources**	7866	7866	7869	7858	7846	7810	7813	8365	8368	8368	8516	8516	8812	8960	9108	9256
3	**Planned Resources**	0	0	0	0	0	0	549	0	0	148	0	296	148	148	148	736
4	**Firm Purchases:**																
	EEI (MW)	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200	200
	OMU (MW)	197	196	195	194	193	192	191	191	190	189	188	187	186	185	184	183
	OVEC (MW)	209	209	179	179	179	179	179	179	179	179	179	179	179	179	179	179
5	**Firm Purchases Non-Utility**	0	0	0	0	0	0	0	0	0	112	112	112	112	112	112	112
7	**Committed Capacity Sales**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
8	**Planned Retirements**	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
	Total Supply	8472	8471	8443	8431	8418	8382	8933	8935	8937	9196	9195	9490	9637	9784	9931	10666
9	**Reserve Requirements**	816	805	824	834	857	868	890	905	915	942	960	971	994	1015	1025	1055
10	**Excess (Deficit)**	1827	1918	1733	1637	1439	1316	1685	1566	1484	1522	1381	1583	1545	1518	1587	2075
11	**Reserve Margin (%)**	45.3%	47.4%	43.4%	41.5%	37.5%	35.2%	40.5%	38.2%	36.7%	36.6%	34.2%	36.8%	35.8%	34.9%	35.7%	41.5%

Note: Capacity and peak reduction for 2004/05 winter are planned values
Peak for winter 2004/05 is from actual on January 18, 2005

8.(4)(b) On planned annual generation:

1. **Total forecast firm energy requirements;**
2. **Energy from existing and planned utility generating resources disaggregated by primary fuel type;**
3. **Energy from firm purchases from other utilities;**
4. **Energy from firm purchases from nonutility sources of generation; and**
5. **Reductions or increases in energy from new conservation and load management or other demand-side programs;**

The requested information can be found in Table 8.(4)(b) on the following page.

Table 8.(4)(b)

Kentucky Utilities Company / Louisville Gas & Electric Company

Forecast Annual Energy (GWh)

1	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy Requirements	33,808	35,243	36,054	36,897	37,562	38,221	39,031	39,745	40,593	41,385	42,133	42,819	43,624	44,524	45,406	46,282

2 Energy by Fuel Type	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Coal	32,819	29,850	30,413	31,282	31,351	32,528	33,392	33,808	34,444	34,030	34,837	34,974	35,398	36,363	37,359	38,880
Gas	198	529	783	1,004	1,287	762	685	944	1,117	1,180	1,396	1,653	2,049	1,978	1,871	1,218
Oil	(0)	0.1	0.1	0.1	0.2	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Hydro	309	291	306	325	372	397	420	442	495	1,655	1,655	1,655	1,655	1,655	1,655	1,655

3 Firm Purchases From Other Utilities	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
OMU	1,586	1,799	1,798	1,526	1,780	1,776	1,776	1,775	1,767	1,763	1,485	1,761	1,748	1,750	1,744	1,743
EEI	1,648	1,451	1,451	1,456	1,451	1,451	1,451	1,456	1,451	1,451	1,451	1,456	1,451	1,451	1,451	1,456
OVEC	1,371	1,202	1,170	1,173	1,172	1,145	1,134	1,149	1,150	1,139	1,150	1,157	1,159	1,163	1,163	1,168
Other	183	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

4	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Purchases From Non Utility	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None	None

5	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Reductions / Increases in Energy	0	(110)	(117)	(126)	(136)	(146)	(156)	(155)	(155)	(154)	(154)	(153)	(152)	(152)	(152)	(149)

Notes: 2004 numbers are actuals.

8.(4)(c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.

The requested information can be found in Table 8.(4)(c) on the following page.

Table 8.(4)(c)

Kentucky Utilities Company / Louisville Gas & Electric Company

Total Energy Input and Total Generation by Primary Fuel Type

Coal	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy (GWh)	32,819	29,850	30,413	31,282	31,351	32,528	33,392	33,808	34,444	34,030	34,837	34,974	35,398	36,363	37,359	38,880
Total (000 Tons)	14,834	13,644	13,952	14,382	14,439	14,825	15,104	15,298	15,577	15,408	15,767	15,814	15,986	16,409	16,751	17,357
(000 MBTUs) Consumed	347,397	317,220	323,211	332,211	332,668	341,583	348,076	352,433	358,919	355,076	363,271	364,429	368,293	378,103	358,332	354,980

Gas	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy (GWh)	198	529	783	1,004	1,287	762	685	944	1,117	1,180	1,396	1,653	2,049	1,978	1,871	1,218
Total (000 MCF)	1,778	6,088	8,921	11,376	14,450	8,768	7,885	10,793	12,682	13,381	15,736	18,673	23,132	22,328	21,008	13,747
(000 MBTUs) Consumed	1,828	6,088	8,921	11,376	14,450	8,768	7,885	10,793	12,682	13,381	15,736	18,673	23,132	22,328	21,008	13,747

Oil	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy (GWh)	(0.1)	0.1	0.1	0.1	0.2	0.0	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.1	0.0	0.0
Total (000 Gallons)	304	2	1	2	1	2	2	2	1	1	1	1	1	1	1	2
(000 MBTUs) Consumed	43	1	1	1	3	1	1	2	2	2	1	1	1	1	0	0

Hydro	2004	2005	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019
Energy (GWh)	309	291	306	325	372	397	420	442	495	1,655	1,655	1,655	1,655	1,655	1,655	1,655

Notes: 2004 numbers are actuals.

8.(5) The resource assessment and acquisition plan shall include a description and discussion of:

8.(5)(a) General methodological approach, models, data sets, and information used by the company;

The Companies' resource planning process involves: 1) establishment of a target reserve margin criterion, 2) assessment of 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 options.

To aid in the integrated resource planning process, the Companies use a state-of-the-art software package from NewEnergy Associates called Strategist® to evaluate resource options. Strategist® contains several modules, which can be executed in various ways to evaluate resource options. The Load Forecast and Adjustment ("LFA"), Generation and Fuel ("GAF"), Proview ("PRV") and Capital Expenditures and Recovery ("CER") modules of Strategist® are used to evaluate resource options. PRV uses the LFA and GAF modules in a production analysis along with construction expenditure information from the CER to suggest an optimal and several sub-optimal plans based on the minimum PVRR criterion. Strategist® is used in various sensitivity scenarios to determine optimal resource plans. A more detailed description of how Strategist® is used and its input data is contained in a report titled *2005 Optimal Expansion Plan Analysis* (January 2005) in Volume III, Technical Appendix.

Demand Side Management Resource Screening and Assessment

The Companies held discussions with the DSM Advisory Group relative to the DSM screening process. The Companies identified a broad range of DSM alternatives and developed a long list of alternatives. Each alternative on this long list was investigated and evaluated using a two-step screening process. The first phase was qualitative in nature, and each alternative was evaluated based on four criteria (see Table 8.(5)(c)-1 for a listing of the criteria). The second phase of screening was quantitative in nature and was performed using EPRI's DSManager software. DSManager is a PC-based software package developed by EPS Solutions under contract with EPRI. It is a screening tool that determines the cost effectiveness of DSM programs by modeling their costs and benefits over a period of time. The program simplifies the "real world" by using 48 typical days to represent a year. There are four daily load shapes per month, each representing a specific type of day. The day types are high, medium, and low weekday, and weekend. Additional detail on this process is contained in the report titled *Screening of Demand-Side Management (DSM) Options* (December 2004) contained in Volume III, Technical Appendix.

Supply Side Resource Screening Assessment

Various supply-side options, including both mature and emerging technologies, were evaluated as part of the integrated resource planning process. *Black & Veatch (B&V) 2004 Integrated Resource Plan Supply-Side Data* report dated September 2004 was utilized to perform the detailed screening analysis. B&V provided data on numerous mature and emerging technologies. 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.

8.(5)(b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;

The process of determining an optimal IRP involves the modeling of the Companies' existing generation system and various possible options, either demand-side or supply-side, as resources to meet growing customer needs. Key assumptions and uncertainties are: 1) forecasted fuel prices, 2) forecasted customer load requirements, 3) capital and operating expenses related to new generation construction, 4) Clean Air Act Compliance, 5) availability of existing and new generating units and purchases, 6) weather uncertainties, 7) potential regulation of CO_2 emissions, 8) regulation 316b for cooling water intake structures, 9) the aging of generating units, 10) fuel cost uncertainty, and 11) MISO Day 2 market possibilities. A discussion of each key issue follows.

Fuel Forecast

The Companies' fuel forecasts are updated annually as part of the Companies' planning cycle. The Companies solicit contract bids for coal to satisfy the near term needs of each plant. The first five years of fuel forecast is a combination of the prices of the current contracts in place and using the forward price curve. Beyond that 5-year period, prices are escalated to the end of the study period (for both fuel and transportation) by the appropriate escalators provided by Global Insight (Global Insight, Inc. was formed to bring together the two most respected economic and financial information companies in the world, DRI and WEFA). Global Insight supplies the appropriate escalations for oil as well as for coal for the various coal and oil qualities used at the Companies' generating plants. Oil pricing is based upon current marks and escalated using Global Insight projection rates.

Current market price for natural gas at Henry Hub is supplied to the Companies. Henry Hub is a commodity price for gas, and transportation prices specific to the Companies' area are added. Similar to the coal and oil, escalators are also applied to the natural gas pricing for future years. Forecasted fuel prices and transportation charges are combined and the resulting delivered price to the various generating plants is utilized.

A significant factor influencing the Companies' optimal IRP is the Companies' fuel forecast. The Combustion Turbine and the Combined Cycle technologies, for example, are gas-fired, while the Trimble County Unit 2 is a coal-fired technology. Thus, gas and coal prices may have a significant impact on the selection of an optimal technology type. Therefore, in order to evaluate the effect of gas and coal prices, a fuel sensitivity analysis was incorporated into the Companies' process of developing an optimal IRP. The fuel forecasts were developed by increasing (decreasing) the expected cost of coal. The gas prices were not adjusted. Not adjusting the gas prices is a relatively simple method for evaluating the impact of the "gap," or difference in cost between that of coal and gas. In summary, three fuel price forecasts (Base, High, Low) have been developed and are incorporated into the process of developing an optimal IRP. Fuel sensitivities were also factored into the screening of supply-side technologies as discussed in the report titled *Analysis of Supply-Side Technology Alternatives* (November 2004) contained in Volume III, Technical Appendix.

Forecasted Customer Load Requirements

The load forecast (energy and demand) is another significant factor influencing the Companies' optimal resource plan analysis. Each resource option is designed or selected – within a system context - for optimal performance at a specific level of utilization. For instance, CTs have relatively low construction costs (compared to coal-fired units), but have high operation and maintenance costs. Conversely, coal-fired units have high construction costs (per kW of installed capacity), but have much lower fuel and O&M costs. The economics of adding any unit to a generation system depends on the lifetime duty which that unit will perform. Significant economic penalties (higher-than-planned costs of system development and operation) may be incurred if a unit is operated for an extended period outside its design duty range.

In developing a portfolio of generating assets it is important to ensure that the economics of the selected expansion plan are robust within a reasonable range of load growth uncertainty. For example, if load growth turns out to be higher than expected, CT capacity - added to meet peak demands only – may be called upon for intermediate duty, adding significant cost to system operations. Conversely, with lower-than-expected load growth, baseload capacity may be under-utilized. The planning function must consider the impacts of uncertainty in load growth on system economics and – recognizing the necessary lead-times required to construct different types and sizes of plant – develop an expansion plan which provides appropriate flexibility throughout the planning term.

To address this issue, the Companies incorporate load sensitivity analysis into the process of developing the optimal IRP. In summary, three load forecasts were developed. The three forecasts depict an expected system load growth case, a case where system load growth exceeds expected growth and a case in which system load growth is less than expected. The resulting forecasts are referred to respectively as the *base, high,* and *low*. The details of and the basis for the various load forecasts are described in Volume II, Technical Appendix.

New Unit Estimated Costs

A significant change in the capital cost of a new unit or its operating expenses can result in a different selection of units in the optimal IRP strategy. In September 2004, Black & Veatch (B&V) provided the Companies with a report titled *2004 Integrated Resource Plan Supply-Side Data.* This B&V report contained various supply-side technology types, descriptions and technical explanations, capital costs and capital cost ranges, facility MW sizes, fuels and other technology-specific parametric data from engineering cost studies. As discussed in the report titled *Analysis of Supply-Side Technology Alternatives* (November 2004) contained in Volume III, Technical Appendix, a base, low and high capital cost sensitivity was incorporated into the screening analysis.

Market forces can and do have a major impact on the pricing and availability of new units. The pricing and availability of combustion turbines, or any other resources that are highly desirable by entities involved in delivering power, may be drastically different than those prices utilized in the supply-side screening analysis and in the integrated analysis when it comes time to actually purchase and install the units. The Companies will continue to closely monitor activity in the market through its RFP process and industry contacts so that the least-costly resource will be utilized to reliably meet customer demand.

Clean Air Act Compliance Plan

To comply with the Clean Air Act Amendments (CAAA) of 1990, the Companies have completed a number of major projects to reduce the amount of nitrogen oxides ("NO_x") emitted from its steam generating plants. With implementation of the CAAA, the Environmental

Protection Agency ("EPA") capped NO_x emissions from electric generating units at 0.15 pounds per million BTUs of historic heat input.

The required NO_x reductions were achieved by the Companies through the installation of Selective Catalytic Reduction Systems ("SCRs") and other NO_x control technologies such as advanced low-NO_x burners, overfire air systems, and neural networks on many of its generating units to enable better control of the boiler combustion process. Between 1990 and 2000, the Companies reduced their NO_x emissions by over 40 percent by installing low NO_x burners and overfire air systems. These installations were performed during regularly scheduled maintenance outages (to minimize asset down time). Implementation of these actions on many of the Companies' units constituted the initial phase of the Companies' NO_x compliance efforts.

Completion and operation of the Companies' first SCR occurred in 2002 and the most recent SCR came on line in May 2004. In all, SCR installation was performed on six of the Companies' baseload generating units (Trimble County Unit 1; Mill Creek Units 3 and 4; and Ghent Units 1, 3, and 4).

The SCR process is the most aggressive means of post-combustion NO_x removal currently available to coal-fired boilers and provides the greatest degree of control. An SCR is a large, reactive "filter," about the size of a ten-story building that houses a catalyst used to convert the NO_x emissions into the components of nitrogen and water. Like the annual sulfur dioxide ("SO_2") allocation program under the Acid Deposition Control Provisions of the CAAA of 1990, EPA's NO_x regulations allow for the totaling of NO_x emissions over the Companies' entire system during the ozone season and do not require compliance by each individual unit or site location. Therefore, to reduce compliance costs, the Companies are reducing NO_x emissions more than required on some of its generating units to stay below the system-wide tonnage cap of

12,447 tons. Operation of the SCR systems in 2004 has allowed the Companies to reduce annual NO_x emissions by more than 40 percent in comparison to 2000 NO_x emission levels and nearly 60 percent when emissions from only the ozone season (May through September) are considered. Additional detail on the Companies' NO_x compliance plan is contained in the report titled *2005 NO_x Compliance Study* (January 2005) contained in Volume III, Technical Appendix.

Although most of the Companies' larger coal-fired generating units are already fitted with Flue Gas Desulfurization Units ("FGDs"), additional control of SO_2 must be achieved to comply with the multi-phased SO_2 reduction process mandated by the CAAA. Phase II of the Acid Deposition Control Program of the CAAA established an annual SO_2 emissions cap at approximately 8.9 million tons by the year 2000. The Companies' current operations emit more than the annual SO_2 limit, but the extra emissions are allowed because the Companies' have a "bank" of saved emission credits. These credits were accrued in the years prior to 2000 when the Companies' produced less than their annual SO_2 emission allotment and could save the difference between the emitted SO_2 and the former SO_2 cap.

The Companies' have used these accrued credits since 2000 to offset SO_2 emissions in excess of the annual limitation. Additionally, the Companies' have increased the removal efficiencies of all existing FGD units to conserve the emission credits. In spite of these efforts, the Companies' anticipate that the allowance bank will be depleted before the end of 2007. When the emission allowances are depleted, the Companies will be forced to purchase allowances from the market or find a way to make additional reductions in SO_2 emissions. As a result, the Companies' have planned a number of projects to reduce fleet-wide SO_2 emissions, including the installation of FGDs on Ghent Units 2, 3, and 4 and E.W. Brown Units 1, 2, and 3.

There are many different designs of FGD equipment. The equipment planned for Ghent and E.W. Brown units are wet limestone, forced-oxidation systems, very similar to FGD equipment already in use at the Ghent, Trimble County, Cane Run, and Mill Creek Stations. These types of systems are among the highest in SO_2 capture efficiency. A generalized description of this system would consist of crushing and slurrying the limestone material into liquid form and introducing it into the flue gas stream, typically by spraying it. The limestone reacts with the SO_2 gas creating a product in solution that falls out of the flue gas stream. The resulting liquid is collected and air is forced into it to further oxidize the material turning it into synthetic gypsum. Depending on the quality of the gypsum, it can be used for beneficial re-use projects (i.e., sold to wallboard makers, used as structural fill material, etc.).

Construction of these FGD systems will lessen the need to purchase SO_2 allowances. However, due to forecasted load and generation growth, it will still be necessary to purchase some allowances within this planning period to cover predicted emissions. Additional detail on the Companies' SO_2 compliance plan is contained in the report titled *2004 SO_2 Compliance Strategy for Kentucky Utilities and Louisville Gas and Electric (*November 2004*)* (previously filed in PSC Case No. 2004-00426) is also contained in Volume III, Technical Appendix.

Meanwhile, additional EPA regulation is on the horizon for coal-fired operations. EPA proposed a rule to control mercury from coal-fired sources on December 23, 2003 and is currently scheduled to promulgate a final rule by late in the first quarter of 2005. The proposed rule contains two options for the regulation of mercury emissions: installation of control technologies and establishment of a cap-and-trade program.

The "command-and-control" alternative would require the application of maximum achievable control technology ("MACT") to each station. MACT would be applied to ensure that the station would meet the enumerated emission cap for the generalized type of coal (i.e., bituminous coal, sub-bituminous, lignite, etc.) burned.

The "cap-and-trade" program, similar to that already in place for SO_2 and NO_x, would establish a cap on mercury emissions based on the type of coal burned. Companies would be allotted a certain number of mercury allowances that would be used to cover emissions or be traded to others. The cap-and-trade option would allow the averaging of emissions over a company's fleet. Therefore, a more economical distribution of control technologies could be applied.

The Companies have, in the past, partnered with the Kentucky Geological Survey to better define and analyze the amount of mercury emitted from its plants. More recently, the Companies have participated in a Department of Energy funded study, contracted to CONSOL Energy (a subsidiary of CONSOL Coal Company) to study the impact of SCR devices on mercury emissions from coal-fired power plants. EPRI became involved in this study and funded additional testing to determine mercury removal across additional pollution control devices in power plants.

Conventional air pollution control equipment (like electrostatic precipitators, FGDs, and SCRs) removes some mercury from power plant emissions. Several new technologies are also being developed that are specific to the removal of mercury. Additionally, the Companies continue to invest in mercury/hazardous air pollutant research through membership in the EPRI. With this data, planning can be conducted to determine the compliance path the Companies will need to follow to meet the obligations of future regulation.

Existing and New Unit/Purchase Availability

The Companies' existing capacity resources are comprised of both owned generating units and purchase power agreements. A significant amount of historical data exists on these units and was used to model the future availability of the units. The availability of new generating units and purchases was determined based on the Companies' experience and projected availability from Black & Veatch (B&V) report titled *2004 Integrated Resource Plan Supply-Side Data.*

The Companies are two of fifteen sponsoring companies of the Ohio Valley Electric Corporation ("OVEC") and presently receive 9.5% of the equity in the generating capacity. Full details of what has transpired with OVEC since the Companies 2002 IRP are presented in Section 6.

Market forces can drastically affect the availability and prices of purchase power from the wholesale market as a future resource. The Companies accounted for the uncertainty of price spikes and their respective impact on meeting peak demands in the optimization studies by excluding peaking type power purchases from the IRP analysis. Peaking type purchase power opportunities in optimization studies would serve only to evaluate the delay of CT construction for short periods of time, which is already being considered in greater detail by the Companies' RFP process.

Uncertainty in the Planning Process Caused by Weather

Recent mild summer experiences indicate that during peak load periods, the Companies' reserves are not approaching maximum utilization. The Companies' planned reserve margin for the 2004 summer season was estimated prior to the summer to be 26.4%. Due to mild summer temperatures, on the peak day after contingencies, the actual operating margin was 30.4% in 2004. The differences between the expected reserve margin and the actual operating margin were due to the variances in load, available generation, reduced capacity due to equipment problems, and available purchases.

During the hour ending 4:00 p.m. eastern standard time on July 13, 2004 the Companies' peak load was 6,223 megawatts. This is much lower than the Companies' all-time peak load (including buy-thru customers' load) of 6,513 megawatts which was established on August 5, 2002. The Companies' July 2004 capacity rating was 7,610 megawatts, 256 megawatts less than the winter capacity rating, and planned to have firm purchase from OMU (184 MW), EEInc. (200 MW), and OVEC (209 MW) that total 593 MW. In general, the Companies have less installed capacity available in the summer season than in the winter season due to the effect of the summer weather conditions on the operating characteristics of each unit. At the time of the 2004 peak, the Companies' resources were composed of KU/LGE-owned units and 527 megawatts of native-load purchases from OVEC (144 MW), EEInc. (165 MW), and OMU (218 MW). On the 2004 summer peak day, capacity available for native load from Company owned units was only 20 megawatts less than the summer rating due to unit outages. Scheduled purchases totaled to 527 megawatts with no spot market purchases at the time of peak. These factors coupled with a lower than planned peak load (-265 megawatts) resulted in an operating margin of 30.4%, which well exceeds the East Central Reliability Area Coordination Agreement ("ECAR") recommended minimum daily operating reserve requirement of approximately 4%. As a member of ECAR, the Companies strive to maintain a level of daily operating reserve of approximately 4% of projected daily peak load to ensure a high degree of service continuity for its system and ECAR.

Table 8.(5)(b)-1 shows pertinent system data for the 2004 summer peak day. Figure 8.(5)(b) complements Table 8.(5)(b)-1 and illustrates the magnitudes of the Companies' daily summer peak loads during July and August of 2004. As shown in Table 8.(5)(b)-1, the Companies' actual operating margin can be either more or less than expected. Actual operating margin levels vary as a result of abnormal weather, unit equipment problems, and the unavailability of contract purchases.

Table 8.(5)(b)-1
Recent Summer Load Experience

Day	**7/13/2004**
Hour (EST)	**16:00**
Day of Week	**Tuesday**
Planned Capacity	
Utility Owned	7,610
Firm Purchase Contract	593
	8,203
Forecasted Peak Demand	**6,488**
Planned Reserve Margin	
Megawatts	1,715
Margin (%)	***26.4%***
Available Capacity [1]	
Utility Owned	7,590
Firm Purchase Contract	527
Spot market purchases [2]	0
	8,117
Actual Peak Demand	**6,223**
Outages	
Forced	0
Derate	30
Scheduled	0
	30
Actual Operating Margin	
Megawatts	1,894
Margin (%)	***30.4%***

Notes

[1] Available Capacity is defined as the planned capacity less outages and adjusted for actual hourly Ohio Falls generation.

[2] Spot market purchases can be made to displace higher cost owned generation and will be utilized to meet peak demand before other owned Available Capacity.

Figure 8.(5)(b)

Kentucky Utilities Company / Louisville Gas & Electric Company
July 2004 - August 2004 Native Load Experience

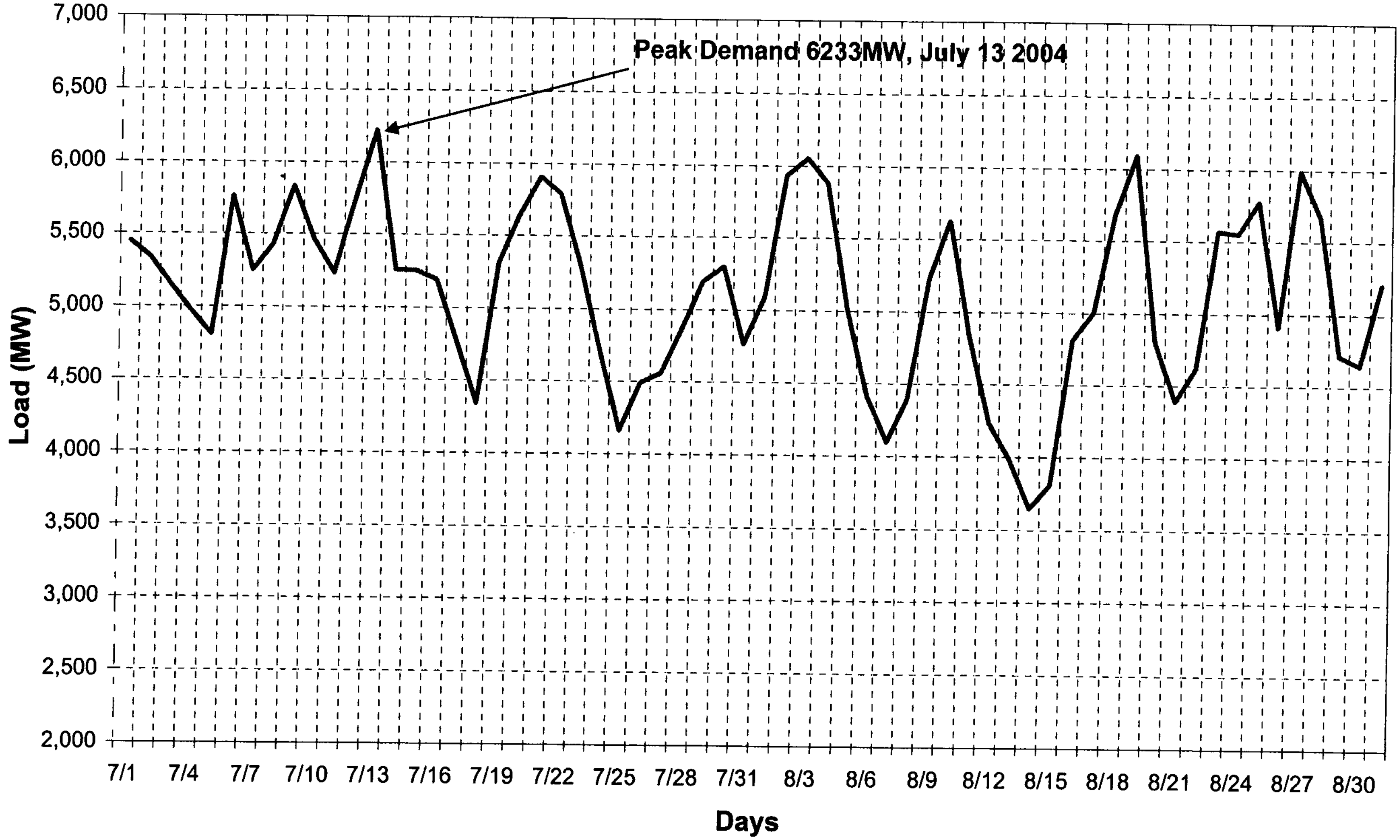


Figure 8.5b

Potential Regulation of CO_2 Emissions

In addition to the actions already being considered to control mercury emissions, EPA is considering the promulgation of regulations to control emissions of carbon dioxide ("CO_2"). Such actions could be undertaken as part of an effort to reduce emissions of greenhouse gases ("GHG") leading to global climate change. However, even with the potential future regulation of CO_2 emissions, no mandatory requirements are in place at this time. Some of the proposed measures are described as follows:

Clean Power Act of 2002 - In March 2001 (marked up in June 2002), Sen. Jeffords (R-Vt.) introduced legislation (S.556) to set national emissions caps (effective in 2008) on power plant emissions of CO_2 (2.05 billion tons), NO_x (1.5 million tons), mercury (5.0 tons), and SO_2 (2.2 million tons). Each fossil fuel utility plant would be required to meet an individual cap (expected to be very stringent) based on its electrical generation. Starting in 2013, after a coal-fired facility had operated for 40 years, the affected generating unit would have to install Best Available Control Technology ("BACT") in addition to meeting its facility-specific emission caps or it would have to shut down. This course of action would discourage the use of coal as a fuel because of the expense of BACT installations for coal-based operations compared to operations fueled by many other sources.

Credit for Voluntary Reductions – Numerous pieces of legislation have been introduced into Congress that would authorize the President to enter into emission-reduction agreements with U.S. businesses and give credit to companies that voluntarily reduce their GHG emissions from 1999 through 2008. These credits could then be used to offset any obligation for GHG reductions that might stem from future domestic control requirements.

Kyoto Protocol – The 1997 Kyoto Protocol on climate change, if ratified by the Senate, would require the U.S. to reduce emissions of six GHGs (including CO_2) between 2008 and 2012 to levels seven percent below those of 1990. In Congress, several committees held hearings on the Kyoto Protocol and its implications. A number of bills, resolutions and provisions in appropriations bills were introduced or considered. Most seek limitations on activities of the U.S. government that are or could be seen as related to carrying out the goals of the Kyoto Protocal. Certain measures to control CO_2 emissions (along with SO_2, NO_x and mercury) from power generating facilities have also been introduced into Congress and discussed. In late 2001, the Bush Administration rejected the Kyoto Protocol and indicated that the U.S. would not participate until developing countries also make commitments to participate in GHG limitations. President Bush stated that the treaty – worked out by the Clinton administration, but not ratified by the Senate – could cost millions of American jobs. An economic report to Bush warned that the Kyoto requirements could erode the nation's gross domestic product by up to four percent in 2010. The report by the Council of Economic Advisers said that this is "a staggering sum when there is no scientific basis for believing this target is preferable to one less costly."

In February 2002, President Bush released his global climate change plan calling for an 18 percent reduction in GHG emissions over the next decade. The new climate change policy consists of voluntary goals rather than mandatory targets, and links GHG emissions to economic output. The goal is to lower the U.S. rate of GHG emissions from the 2002 level of 183 metric tons per million dollars of Gross Domestic Product ("GDP") to 151 metric tons per million dollars of GDP in 2012. By significantly slowing the growth of GHG, the Administration aims to put America on a path toward stabilizing GHG concentration in the atmosphere, while sustaining the economic growth needed to finance investments in a new, cleaner energy structure. The President has also directed the Department of Energy ("DOE") to ensure that companies that register voluntary reductions are not penalized under any future climate policies, and that the DOE give credit to companies that can show real emission reductions. The plan also includes a review of the progress on climate change, on the achievement of the President's goal, and taking additional action, if necessary, in 2012.

More recent action in the CO_2 arena occurred on July 21, 2004 when several states and the city of New York filed a law suit against five large electric power producing utilities. The lawsuit claimed that emissions of carbon dioxide from these utilities presented serious risk to the environment, public health and the economy. The federal common law of "public nuisance" is the basis of the lawsuit. They seek a 3% per year reduction in CO_2 emissions from these companies over a 10-year period and are not seeking monetary penalty.

This is the first time states have sued private companies to achieve CO_2 reductions. The move is believed to be an attempt to force regulation of CO_2 through the courts in the absence of mandatory legislation. The claim will be difficult to substantiate because proof must be shown that the emissions from these specific companies and their facilities are the cause of quantifiable health risk.

As previously stated, there are presently no regulations that would restrict the emission of CO_2; however, there are multiple proposals that may receive future consideration. To capture this possibility in the Companies' IRP process, a range of environmental cost adders for potential taxes on CO_2 emissions was included in the supply-side screening analysis. Details of this process can be found in the report titled *Analysis of Supply-Side Technology Alternatives* (November 2004) contained in Volume III, Technical Appendix.

316 (b) – Regulation of cooling water intake structures

Section 316(b) of the Clean Water Act requires that cooling water intake structure reflect the best technology available ("BTA") for minimizing "adverse environmental impacts" to aquatic organisms. EPA has developed rules to implement Section 316(b) in three phases: new facilities, existing electric generation facilities, and existing manufacturing and small utility and non-utility power producers. In December 2001, EPA promulgated the Phase I new facility rule establishing cooling towers as BTA.

A final rule for Phase II existing electric generation facilities became effective on September 7, 2004. However, this final rule does not establish cooling towers as BTA. Rather, this rule sets significant new national technology-based performance standards aimed at minimizing the adverse environmental impacts by reducing the number of aquatic organisms lost as a result of water withdrawals or through restoration measures that compensate for these losses. This final rule applies to existing large electric generation facilities (i.e. those facilities which withdraw 50 million gallons per day or more of water and which use more than 25% for cooling purposes). Facilities have up to three and one-half years to perform aquatic studies and submit a Comprehensive Demonstration Study.

The Companies do have facilities that meet the applicability criteria for the Phase II final rule. Current plans include performing studies at the affected facilities and waterways in the years of 2005, 2006, and 2007. The results of those studies will determine investments to be made in the years of 2008 and 2009 to mitigate any potential compliance problems.

Aging Generating Units

The generating units in the Companies' fleet continue to age. Some of the oldest steam-generating units across the system include Tyrone Units 1 and 2. Each of these units is over fifty years old, which is beyond the typical design life for a coal-fired unit. Some of the oldest combustion turbines are the LG&E smaller-sized combustion turbines and the KU Haefling combustion turbines. Each of these units is over 30 years of age, which is considered typical life expectancy for small frame combustion turbines.

Having operated past their design lives, these units run a greater risk of a catastrophic failure than other units. The economics surrounding the continued operation of these units are periodically reviewed to ensure the efficiency of the overall system. The relatively high production costs of these units and the 2004 NO_x restrictions (as well as any future imposed regulations) only worsen their relative economics. It could become economic to retire many of these units even without a significant mechanical failure. Any decision to retire generation would change the future capacity needs.

To mitigate the exposure to the potential failure/retirement of these aging units (as shown in Table 8.(5)(b)-2), the Companies performed sensitivities to determine the impact on the optimal expansion plan. The sensitivities evaluate the retirement of the entire group of units in 2010, the first year that the Clean Air Interstate Rule ("CAIR") is applicable and the year in which additional coal generation will be added. Further details can be found in the report *2005 Optimal Expansion Plan Analysis* (January 2005) contained in Volume III, Technical Appendix. Any decision to retire generation would change the future capacity needs.

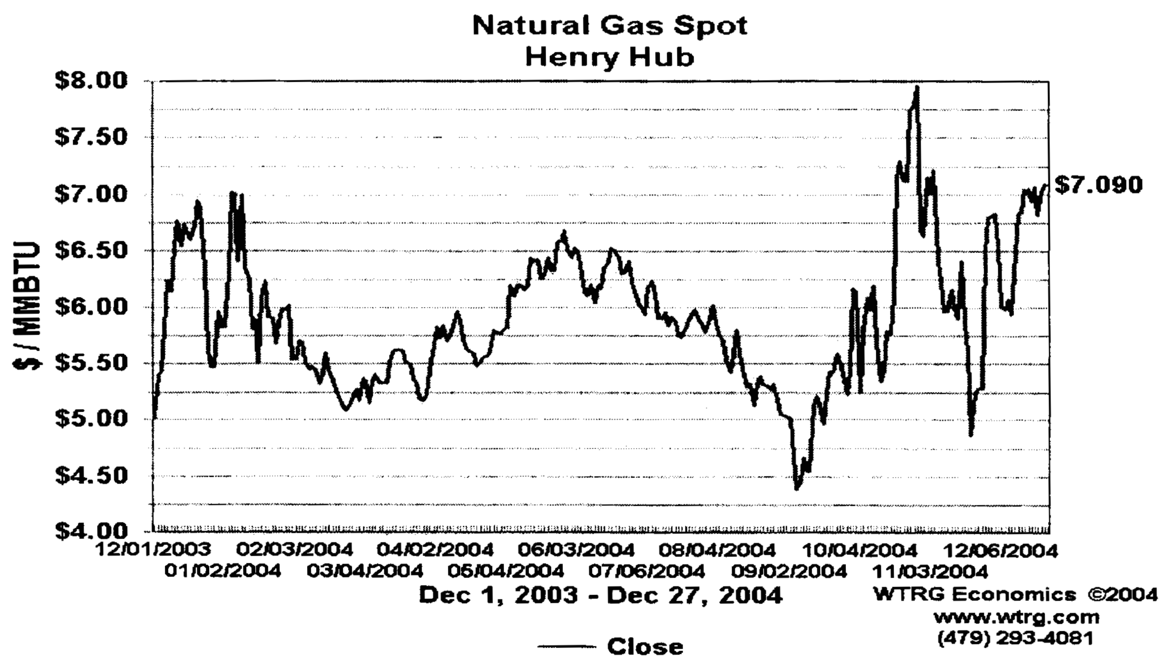
Table 8.(5)(b)-2
Aging Units

Type of Unit	Plant Name	Unit	Summer Capacity	In Service Year	Age (2005)
Steam	Tyrone	1	27	1947	58
Steam	Tyrone	2	31	1948	57
CT	Waterside	7	11	1964	41
CT	Waterside	8	11	1964	41
CT	Cane Run	11	14	1968	37
CT	Paddy's Run	11	12	1968	37
CT	Paddy's Run	12	23	1968	37
CT	Zorn	1	14	1969	36
CT	Haefling	1,2,3	36	1970	35

Fuel Cost Uncertainty

Natural gas prices have fluctuated quite a bit, even looking at 2004 alone; they range from about $4.30 up to almost $8.00 per mmbtu. The data in Table 8.(5)(b)-3 below is from the website http://www.wtrg.com/daily/ngspot.gif on December 29, 2004.

Table 8.(5)(b)-3



Moreover, there is always an uncertainty associated with fuel transportation: from railroad strikes to frozen rivers in obtaining coal deliveries by rail and barge, respectively. With natural gas delivery come other uncertainties: since gas used for electric generation can vary substantially from hour to hour, meeting that increased demand requires the development of gas services with flexible delivery features.

MISO Day 2 Markets

The impact of the MISO is a significant source of uncertainty for the Companies. This is driven mostly by numerous aspects of the proposed MISO Day 2 Markets. The Day 2 markets are a specific component of an ongoing Commission investigation into the Companies membership in MISO in Case No. 2003-00266. The Companies expressed their concerns about these uncertainties in detail in the record of that proceeding, which is a matter pending before the Commission at this time.

8.(5)(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;

Demand-side Management Screening

Prior to the optimization process, a screening analysis of Demand-Side Management ("DSM") options was conducted. The purpose of the screening analysis was to evaluate cost effective DSM options to use in Strategist® optimizations. The following is a summary of the DSM screening methodology and subsequent findings. A detailed report of the screening analysis titled *Screening of Demand-Side Management (DSM) Options* (December 2004) can be found in Volume III, Technical Appendix.

The Companies invited members of the DSM Advisory Group to submit proposals for DSM options to be analyzed. Each alternative on a list of potential alternatives was investigated and evaluated using a two-step screening process. The first step was qualitative in nature, where each alternative was evaluated based on four criteria. The alternatives that passed the first step underwent a second step of screening that was quantitative in nature. The quantitative screening process had two separate phases, which are discussed below. The DSM programs that passed the quantitative screening process competed with supply-side alternatives in the integrated analysis.

The qualitative analysis began with the selection of the criteria on which to base the comparison of DSM options. Based upon the Companies' objectives to provide low-cost, reliable energy to our customers four criteria were selected. The next task was to assign weights or values to each of the criteria. The highest weights were assigned to the criteria judged to be the most important to develop a successful DSM program. The most important criterion was the cost effectiveness of peak demand reduction. Each potential DSM option was evaluated, based on a scale of 1 to 4, using the four criteria. The four criteria, their weights, and an explanation of each are shown in Table 8.(5)(c)-1.

Table 8.(5)(c)-1
Qualitative Screening Criteria

Criteria	Description	Weighting
Customer Acceptance	The degree to which an acceptable number of customers is willing to participate to create a successful program. The highest scores would be reserved for measures that have beneficial side effects, e.g., enhanced worker productivity or improvements in the quality of a product or service.	25%
Technical Reliability	The degree to which the technology is commercially available to evaluate this measure.	15%
Cost Effectiveness of Energy Conservation	The cost of this measure to reduce a kWh relative to the cost of generation in $/kWh.	25%
Cost Effectiveness of Peak Demand Reduction	The cost of this measure to reduce a kW relative to the cost of generation in $/kW.	35%

The programs that passed the qualitative screening process were modeled in more detail using EPRI's DSManager software as part of the quantitative screening process. DSManager calculates the net present value of the quantifiable costs and benefits assignable to both the Companies and the customers participating in a DSM program. For each DSM initiative, DSManager requires the administrative costs, participant's costs, life span of the technology, expected level of participation, expected level of free riders, and rate schedules. DSManager calculates changes to the participant's bill, changes in the Companies' revenue, changes in production costs, and changes in the peak demand. The present value for each DSM alternative is calculated, by DSManager, and reported as the costs and benefits using the five "California Tests." These five tests include the participant, utility cost, ratepayer impact measure ("RIM"), total resource cost ("TRC"), and societal cost tests. The Companies used only the participant and TRC tests to screen DSM options. The participant test includes changes in all costs and benefits to the customer installing the DSM option. The TRC test combines the RIM and participant tests and indicates overall benefits of the DSM option to the average customer, whereas the RIM test considers all impacts to the non-participants.

The quantitative screening was set up in two phases. In Phase I, the cost to administer the program was not considered and it was assumed that the program had only one participant per company. This phase was created to remove non-cost effective programs. If the benefits of a program do not exceed the cost of the program without the administration cost, then it will not pass with a higher penetration of customers and the added burden of the administrative costs. The only cost included in this phase was the incremental cost of the DSM alternative. Each program that passed Phase I of the quantitative screening process was put through a program design phase (Phase II). The costs to administer the programs and the expected levels of penetration were added to the programs that passed Phase I. Each program has to pass the Participants Test and the TRC to be evaluated further.

Five programs passed the quantitative screening process and were passed on to the optimization process.

Supply-side Screening

As a precursor to the optimization process, a technology screening analysis was conducted. The purpose of the screening analysis was to evaluate, compare and suggest the least-cost supply-side options to use in Strategist® optimizations. The following is a summary of the technology screening methodology and subsequent findings. A detailed report of the screening analysis titled *Analysis of Supply-Side Technology Alternatives* (November 2004) can be found in Volume III, Technical Appendix.

Black & Veatch (B&V) provided the Companies data for determining the relative cost and performance of current/advanced electric generation and storage technologies. No technology was excluded from the screening analysis based solely on its technical maturity, practicality, or feasibility. For example, even though climatically the information for Kentucky suggests wind turbine technology would not be a practical supply-side option in Kentucky, wind turbine technology was not excluded from the analysis.

In order to pass a comprehensive list of supply side options to Strategist® for evaluation, two cases along with three sensitivities were incorporated into the screening analysis. The first case, referred to as the base analysis, includes the impact that the emission of SO_2 and NO_x can have on the selection of technologies. The second case, which also includes the cost of SO_2 and NO_x emissions, evaluates the potential additional cost of carbon dioxide emissions. The three sensitivity variables were capital cost, heat rate, and fuel cost. For each of the three sensitivity variables, high and low values were determined, in addition to the base values supplied by B&V. The percent adjustment made to capital costs originate from B&V and is based on the technology's development rating. The capital cost adjustment is applied to the total plant cost. The adjustment to the heat rate is a 5% decrease and increase from the base heat rate to adequately represent improved or decreased operating performance of the technology over the designed heat rate. As a result of the three possible values for each of the three sensitivity variables, 27 total possible scenarios exist for evaluation for each of the two cases.

The 30-year levelized screening analysis determined the total annual cost of owning and operating each technology under each of the 27 scenarios and over a range of capacity factors from 0 to 100% in 10% increments. The 30-year levelized cost of each unit option over various capacity factor ranges is displayed in Table 8.(5)(c)-2 for the base case combination of sensitivity variables. The shaded areas represent the least cost \$/kW-yr for each capacity factor level shown. Figure 8.(5)(c)-1 is a graphical representation of the base case least-cost technologies identified in Table 8.(5)(c)-2. Annual capital cost of each unit is calculated using a fixed charge rate. Fixed and variable operation and maintenance costs are included and fuel cost is assumed to be a linear function of capacity factor.

The first, second and third least cost alternatives over each capacity factor range were identified in all 27 scenarios. A total of 11 different technologies and technology types were initially identified as first, second or third least cost alternatives in the base case. After review, however, it was determined that several of these should be removed from the initial list; the reasons are as addressed in *Analysis of Supply-Side Technology Alternatives* (November 2004) in subsection "Base Analysis with SO_2 and NO_x Impact."

Table 8.(5)(c)-2
Levelized Dollars at Various Capacity Factors

Capital Cost- High
Heat Rate- High
Fuel Forecast- High

2004 Dollars ($/kW yr)

	Capacity Factors										
Technology	**0**	**10%**	**20%**	**30%**	**40%**	**50%**	**60%**	**70%**	**80%**	**90%**	**100%**
Pumped Hydro Energy Storage - 500 MW	195	226	----	----	----	----	----	----	----	----	----
Lead-Acid Battery Energy Storage - 5 MW	159	272	384	----	----	----	----	----	----	----	----
Compressed Air Energy Storage - 500 MW	101	152	203	----	----	----	----	----	----	----	----
Simple Cycle GE LM6000 CT - 31 MW	157	225	293	361	429	497	565	633	701	769	837
Simple Cycle GE 7EA CT - 73 MW	108	192	277	362	447	531	616	701	785	870	955
Simple Cycle GE 7FA CT - 148 MW	81	165	248	332	416	500	584	667	751	835	919
Combined Cycle GE 7EA CT - 119 MW	145	198	251	304	357	409	462	515	568	621	674
Combined Cycle GE 7FA CT - 235 MW	116	164	212	261	309	357	405	453	502	550	598
Combined Cycle 2x1 GE 7FA CT - 484 MW	96	144	192	240	288	335	383	431	479	527	575
W 501F CC CT - 258 MW	109	159	208	258	308	358	408	457	507	557	607
Spark Ignition Engine - 5 MW	141	228	316	403	491	578	----	----	----	----	----
Compression Ignition Engine - 10 MW	103	178	254	329	405	480	----	----	----	----	----
Wind Energy Conversion - 50 MW	191	191	191	191	----	----	----	----	----	----	----
Solar Thermal, Parabolic Trough - 100 MW	494	523	553	582	612	----	----	----	----	----	----
Solar Thermal, Parabolic Dish - 1.2 MW	384	400	416	----	----	----	----	----	----	----	----
Solar Thermal, Central Receiver - 50 MW	658	674	690	706	723	739	755	771	----	----	----
Solar Thermal, Solar Chimney - 200 MW	439	455	471	487	504	520	536	552	----	----	----
Solar Photovoltaic - 50 kW	958	982	1007	----	----	----	----	----	----	----	----
Biomass (Co-Fire) - 27.5MW	321	329	338	346	355	364	372	381	390	----	----
Geothermal - 30 MW	664	664	664	664	664	664	664	664	664	----	----
Hydroelectric - New - 30 MW	402	407	412	416	421	425	----	----	----	----	----
WV Hydro	[redacted]						----	----	----	----	----
MSW Mass Burn - 7 MW	1026	1106	1187	1268	1348	1429	1509	1590	----	----	----
RDF Stoker-Fired - 7 MW	1491	1577	1663	1749	1835	1921	2007	2093	----	----	----
Landfill Gas IC Engine - 5 MW	219	264	309	353	398	443	488	532	577	----	----
TDF Multi-Fuel CFB (10% Co-fire) - 50 MW	345	350	355	360	365	370	375	380	385	390	396
Sewage Sludge & Anaerobic Digestion - .085 MW	335	351	367	383	400	416	432	448	464	----	----
Humid Air Turbine Cycle CT - 450 MW	91	135	178	222	266	309	353	397	----	----	----
Kalina Cycle CC CT - 275 MW	114	159	204	249	294	339	384	429	----	----	----
Cheng Cycle CT - 140 MW	140	196	252	308	364	421	477	533	----	----	----
Pressurized Fluidized Bed Combustion - 250 MW	213	271	329	387	445	503	561	619	----	----	----
IGCC - 267 MW	237	269	301	333	364	396	428	460	492	----	----
IGCC - 534 MW	207	239	270	302	333	365	396	427	459	----	----
Fuel Cell - 0.2 MW	1394	1453	1512	1572	1631	1691	----	----	----	----	----
Peaking Microturbine - 0.03 MW	122	217	----	----	----	----	----	----	----	----	----
Baseload Microturbine - 0.03 MW	122	213	304	395	486	577	668	759	----	----	----
Supercritical Pulverized Coal - 500 MW	167	189	211	233	255	277	299	321	343	364	386
Supercritical Pulverized Coal, High Sulfur - 500 MW	177	196	215	234	253	272	291	310	328	347	366
Supercritical Pulverized Coal - 750 MW	150	172	193	215	236	258	279	301	322	344	365
Subcritical Pulverized Coal - 250 MW	206	228	251	274	297	320	342	365	388	411	434
Subcritical Pulverized Coal - 500 MW	163	185	208	230	252	274	296	319	341	363	385
Subcritical Pulverized Coal, High Sulfur - 500 MW	173	192	211	230	250	269	288	307	326	346	365
Supercritical Pulverized Coal, High Sulfur - 750 MW	159	178	196	215	234	252	271	289	308	327	345
Circulating Fluidized Bed - 250 MW	215	238	262	285	308	331	355	378	401	425	448
Circulating Fluidized Bed - 500 MW	164	186	209	232	255	278	301	324	347	370	393
Ohio Falls 9 and 10	144	144	144	144	----	----	----	----	----	----	----
TC2 732 MW Supercritical Pulverized Coal	129	144	159	174	190	205	[redacted]				
Minimum Levelized $/kW	0	37	73	110	146	183	220	235	250	266	281

Figure 8.(5)(c)-1
Least Costly Technologies For Further Analysis
Base Capital, Base Heatrate, Base Fuel

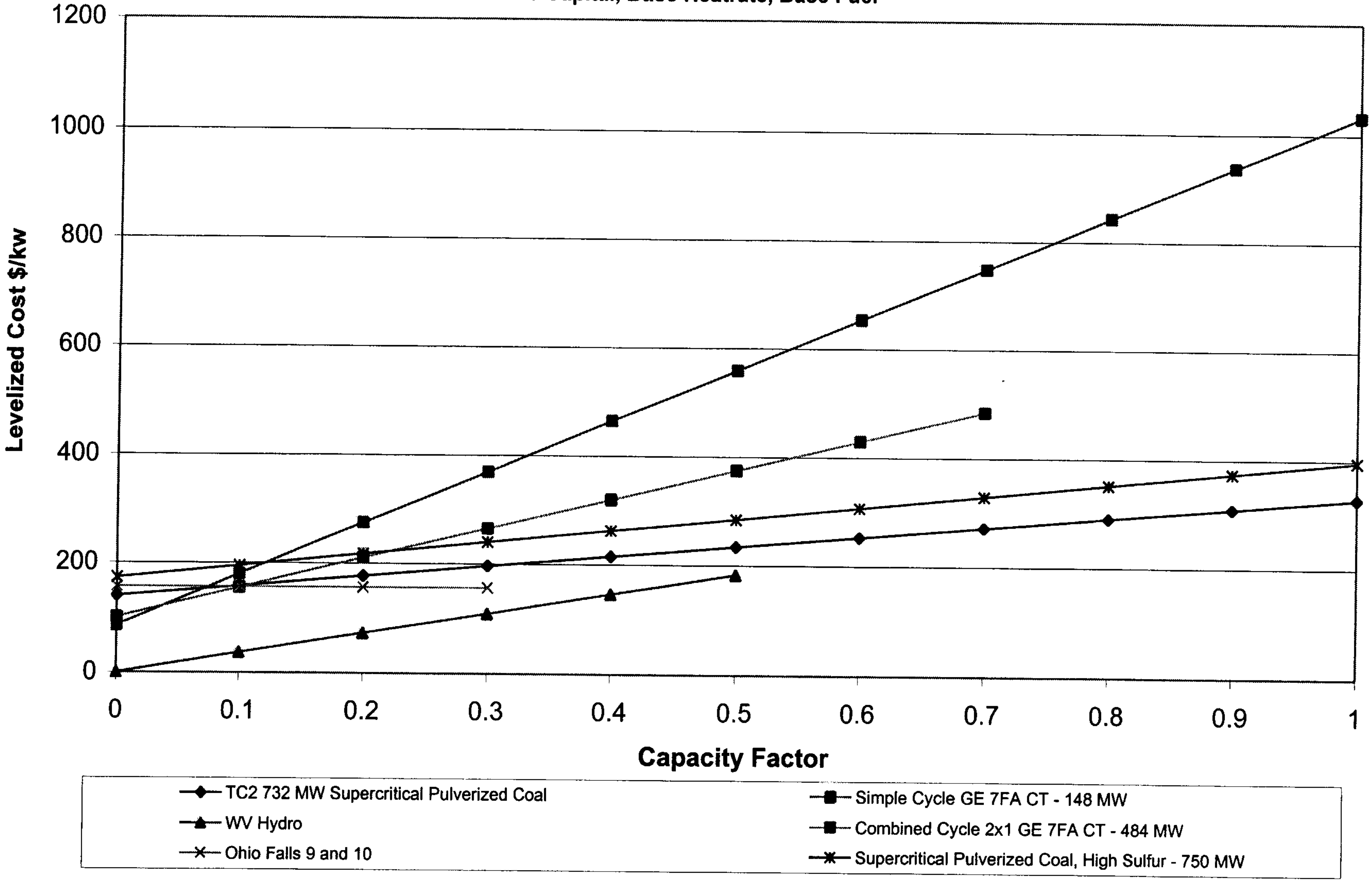


Figure 8.(5)(c)-1

The remaining technologies comprise the final list of technologies suggested for detailed analysis within Strategist®. Table 8.(5)(c)-3 lists those technologies.

Table 8.(5)(c)-3
Technologies Suggested for Analysis
Within Strategist®

Supercritical Pulverized Coal unit at Trimble County Station (TC2)
WV Hydro Purchase Power Agreement ("PPA")
Supercritical Pulverized Coal, High Sulfur – 750 MW
Run of River-Ohio Falls Expansion (Units 9 and 10)
Combustion Turbines at a Greenfield Site
Combined Cycle Combustion Turbine (Un-Phased)

Resource Optimization

The Companies continually analyze purchase power opportunities through the RFP process and through participating in the wholesale marketplace on a real-time basis. Currently peaking type purchase opportunities are compared to CT construction alternatives through the RFP and CCN process. Peaking type purchased power opportunities in optimizations would serve only to evaluate the delay of CT construction for short periods of time, which is already being considered in greater detail by the Companies' RFP process. Thus, peaking-type purchased power was not considered in the integrated analysis. Likewise, because of computer run-time and storage limitations, certain logical restraints were implemented in Strategist®. For example, each technology was reviewed and its earliest possible in-service date was established. With this and other logical constraints in place, a base case appropriate for optimization runs was ready.

The optimal resource strategy is determined based on a minimum expected Present Value of Revenue Requirements ("PVRR") criterion over a 30-year planning horizon and subject to certain constraints, including a target reserve margin of 14% and unit operating characteristics. As precursors to the optimization process, two independent technology screening analyses were conducted, one for supply-side alternatives and the other for demand-side management programs as discussed above.

Sensitivities developed around six key areas: load, fuel, unit retirements, first year available for baseload addition, capital cost of the coal units, and gas transportation for combustion turbines and combined cycle combustion turbines. These sensitivities were evaluated in computer optimization using Strategist®. The sensitivity cases provided support for the recommended plan.

A more detailed description of the process can be found in the report titled *2005 Optimal Expansion Plan Analysis* (January 2005) contained in Volume III, Technical Appendix. The resulting plan is recommended for use as the Companies' IRP. It is further recommended that purchased power continue to be reviewed through the RFP process as an option to delay generation construction. The optimal plan through 2019 is shown below in Table 8.(5)(c)-4.

Table 8.(5)(c)-4
Recommended 2005 Integrated Resource Plan

Year	Resource
2005	1.9 MW New DSM Initiatives
2006	4.9 MW New DSM Initiatives (cumulative totals)
2007	8.8 MW New DSM Initiatives (cumulative totals)
2008	13.4 MW New DSM Initiatives (cumulative totals)
2009	18.5 MW New DSM Initiatives (cumulative totals)
2010	549 MW (75% of 732 MW) Trimble County Unit 2 Supercritical Coal 23.7 MW New DSM Initiatives (cumulative totals)
2011	28.8 MW New DSM Initiatives (cumulative totals)
2012	
2013	148 MW Greenfield CT Unit 1
2014	WV Hydro Purchase Power Agreement
2015	148 MW Greenfield CT Unit 2 148 MW Greenfield CT Unit 3
2016	148 MW Greenfield CT Unit 4
2017	148 MW Greenfield CT Unit 5
2018	148 MW Greenfield CT Unit 6
2019	750 MW Greenfield Supercritical Coal Unit
	Note: Unit Ratings are Proposed Summer Net Ratings

8.(5)(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;

In December 2004, a study was completed which analyzed the Companies' appropriate margin level. This study indicated a 12%-14% range of reserve margin would provide a reliable system to meet customers' demand, and a target reserve margin of 14% is used in this IRP. Details of this study titled *2005 Analysis of Reserve Margin Planning Criterion* (January 2005) can be found in Volume III, Technical Appendix. The January 2005 study is summarized below and is a continuation of efforts to determine the reserve margin level that best balances reliability and cost.

The key variables for studies of this type are the number and length of planned generating unit outages and maintenance outages, generating unit forced and/or equivalent forced outage rates, the availability of purchase power capacity for import, customers perceived cost of unserved/emergency energy, and the expected system load and load factor. The availability of the Companies' existing units is based on historical data. The availability of proposed generating units is such that it falls within the accepted availability for units of a given type, size and class. Since there is no industry standard for the cost of unserved energy, an EPRI study, adjusted to reflect recent market volatility was used to determine a base unserved energy cost. Sensitivity values around the base customer perceived value of unserved energy cost were evaluated, as were market purchases, a high annual load forecast, and finally unit availability sensitivities. The Strategist® computer model was used in the evaluation and the minimization of present value of revenue requirements is the primary decision factor.

Optimization study runs were used to create a least costly ordering of supply-side options for various reserve margin levels (from 7% to 18%, in increments of 1%) given each set of key variables. This methodology was repeated for all possible combinations of the key variables over a range of reserve margins. Study cases run for reserve margins around the reserve margin associated with the minimum PVRR did not show a significant increase in PVRR. Therefore, cases with reserve margins that showed PVRR within a small variance of the minimum PVRR were considered as economically equivalent.

Given the base case assumptions used in this study, together with the detailed sensitivity analysis performed on the purchase power market, unit availability, customer perceived unserved energy cost, annual and summer only load forecast, a target reserve margin in the range of 12%-14% would be considered optimal. For purposes of developing an optimal IRP, a target reserve margin of 14% is being used in this study.

8.(5)(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;

The Companies will continue to develop ways to incorporate uncertainty into their analysis. Also, research will continue with regard to supply-side technologies, both with build and purchase opportunities. Specifically, the Companies plan to continually evaluate the economics of delaying near-term CT generation construction with economic purchase power opportunities. When possible this analysis will be conducted through the RFP process, which allows for a thorough analysis of current CT generation costs and purchased power costs.

8.(5)(f) Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and

The Acid Deposition Control Program was established under Title IV of the CAAA and applies to the acid deposition that occurs when sulfur dioxide ("SO_2") and nitrogen oxides ("NO_x") are transformed into sulfates and nitrates and combine with water in the atmosphere to return to the earth in rain, fog or snow. Title IV's purpose is to reduce the adverse effects of acid deposition through a permanent 10 million ton reduction in SO_2 emissions and a 2 million ton reduction in NO_x emissions from the 1980 levels in the 48 contiguous states.

Sulfur Dioxide (SO_2)

Phase II of the CAAA's Acid Deposition Control Program, described previously in Section 8.(5)(b) under *Clean Air Act Compliance Plan*, established a cap on annual SO_2

emissions of approximately 8.9 million tons by the year 2000. The legislation obtained these SO_2 emission reductions from electric utility plants of more than 25 MW (known as "affected units") through the use of a market-based system of emission allowances. Once allocated, allowances may be used by affected units to cover SO_2 emissions, banked for future use, or sold to others. Allowances were allocated, in tons, to affected units at a level equivalent to 1.2 lbs SO_2/mmBtu using the average heat input value obtained from fuels used between 1985 and 1987.

As stated previously, the Companies' have determined that, before the end of 2007, the Kentucky Utilities' (KU's) SO_2 allowance bank will be depleted. The result is that KU will be required to purchase SO_2 allowances from the market-based system or find another way to offset the SO_2 emissions in excess of the limitation. To curtail the need for purchasing SO_2 allowances, the Companies plan to construct FGD equipment for KU's Ghent Units 2, 3 and 4 and E.W. Brown Units 1, 2, and 3 between 2005 and 2009. Construction of these FGD systems will lessen the need to purchase SO_2 allowances, however, based on forecasted load and generation growth, it will still be necessary to purchase some allowances within this period to cover predicted emissions. Additional detail on the Companies' compliance plan is included in a report titled *2004 SO_2 Compliance Strategy for Kentucky Utilities and Louisville Gas and Electric* (November 2004) (previously filed in PSC Case No. 2004-00426) is also contained in Volume III, Technical Appendix.

Nitrogen Oxide (NO_x)

The Acid Deposition Control Program of the CAAA is not an allowance-based program, but instead established annual NO_x emission limitations based on boiler type to achieve emission reductions. NO_x emission reduction controls must be in place when the affected unit is required to meet the SO_2 standard. The maximum allowable NO_x emission rates for Phase I are 0.45 lb NO_x /mmBtu for tangentially-fired boilers and 0.50 lb NO_x /mmBtu for dry bottom, wall-fired boilers. For Phase II, the maximum allowable NO_x emission rates are 0.40 lb NO_x /mmBtu for tangentially-fired boilers and 0.46 lb NO_x /mmBtu for dry bottom, wall-fired boilers.

All of KU's affected units complied with the Phase II NO_x reduction requirements through a system-wide NO_x emissions averaging plan (average Btu-weighted annual emission limit). Compliance was achieved through the installation of advanced low NO_x burners on Ghent Units 2, 3 and 4.

All of the LG&E affected units complied with the Phase II NO_x reduction requirements on a "stand-alone" or unit-by-unit NO_x emission limitation basis. All of the LG&E units took advantage of the "early election" compliance option under the NO_x reduction program. EPA allowed "early election" units to use the Phase I NO_x limits, thus avoiding the more stringent Phase II NO_x limits. All of the Companies' generating stations operate below their NO_x compliance obligations.

NO_x State Implementation Plan ("SIP") Call

The NO_x SIP Call was promulgated under Title I of the CAAA of 1990 to control the formation and migration of ozone resulting from the presence of NO_x in the atmosphere. Title I requires all areas of the country to achieve compliance with the National Ambient Air Quality Standards ("NAAQS") for ozone, or ground-level smog. In September 1998, EPA finalized regulations (known as the "NO_x SIP Call") to address the regional transport of NO_x and its contribution to ozone non-attainment in downwind areas. EPA maintains that NO_x emissions from the identified states "contribute significantly" to nonattainment in downwind states, and that the SIPs in these states are therefore inadequate and must be revised. EPA's NO_x SIP Call requires 19 eastern states (including Kentucky) and the District of Columbia to revise their State Implementation Plans ("SIPs") to achieve additional NO_x emissions reductions that EPA believed necessary to mitigate the transport of ozone across the Eastern half of the United States and to assist downwind states in achieving compliance with the ozone standard. The final rule requires electric utilities in the 19-state area to retrofit their generating units with NO_x control devices by the ozone season of 2004. EPA set a utility NO_x budget in Kentucky of 36,504 tons of NO_x for the ozone season (based on an emission rate of 0.15 lb. NO_x /mmBtu for utility boilers or an 85% reduction from 1990 levels).

The Companies' portion of the Kentucky NO_x budget amounts to approximately 12,447 tons. The Companies retained Sargent & Lundy to complete a system-wide NO_x compliance study. Sargent & Lundy's scope of work included: performing unit-specific feasibility analysis of NO_x reduction alternatives; analyzing the lowest cost compliance strategies; quantifying capital and O&M costs; identifying plant operational impacts; and, providing a recommended implementation schedule. The Companies developed a NO_x SIP Call compliance plan (as outlined in PSC Case Nos. 2000-386 and 2000-439) which resulted in compliance with the NO_x reduction requirements at the lowest combined capital and O&M life cycle costs across the Companies' generation fleet. The plan implemented NO_x emission reduction technologies on a lowest "\$/ton" of NO_x removed basis, to provide flexibility should regulatory or judicial changes affect the level or the timing of the NO_x reduction required.

In fulfillment of the NO_x SIP Call compliance plan, as mentioned in Section 8.(5)(b) under *Clean Air Act Compliance Plan*, NO_x emissions from the Companies coal-fired generating units were reduced through new investments that financed the installation of SCRs on six of the

Companies' generating units. Additional NO_x control technologies (including advanced low-NO_x burners and overfire air systems) were also installed on nearly every generating unit in the system to reduce the NO_x formed in the combustion zone of the boiler. Additionally, neural network software was installed on many of the generating units to enable better control of the boiler combustion process.

In the future, compliance with this regulation will be dependent on adjustments made to NO_x allocations. The NO_x allocations are re-evaluated by the State of Kentucky every three years. The current allotment that was used for planning was granted for 2004-2006. New allocations will be made for 2007-2009 and into the future. The uncertainty in the number of future allowances will require the Companies to evaluate the need for additional measures to reduce NO_x emissions.

Hazardous Air Pollutants – Mercury

Hazardous Air Pollutants ("HAPs") are regulated under the Title III Air Toxics program. Prior to the CAAA of 1990, NAAQS had only been developed for a few common pollutants and only seven HAPs. Title III established a list of 189 specific air "toxics" which were subject to regulation in order to fill this void. The EPA regulates these toxic emissions by category of industry, rather than by pollutant.

Title III also required the EPA to conduct a study of hazardous air pollutants in utility emissions. In February 1998, the EPA reported to Congress that the most significant risk posed by utility emissions resulted from the deposition of mercury in waters and subsequent uptake by humans via fish consumption or ingestion of water. In late 1998, the EPA issued an information collection request requiring utilities to provide certain information on their coal-fired steam electric generating units that would allow the Agency to calculate the annual mercury emissions from each generating unit.

The information that they collected during 1999 consisted of an analysis of coal shipments (to all power plants) for mercury concentrations; and, an analysis of flue gas (for a subset of power plants – none of the Companies' plants were included) for characterization of mass mercury emissions. In December 2001, the EPA announced its intention to regulate mercury emissions from coal-fired plants.

EPA issued a proposed rule to control mercury from these sources on December 23, 2003 and is scheduled to promulgate a final rule late in the first quarter of 2005. As described previously, the proposed rule contains two options ("command-and-control" and "cap-and-trade") for the regulation of mercury emissions. The "command-and-control" option requires the application of MACT at each station and a cap based on coal type burner while "cap-and-trade" option would establish a program, similar to those already developed for SO_2 and NO_x, for establishing a limit on mercury emissions.

In the review and comment period of this proposal, a wide array of opinions was given. The EPA continues to evaluate the proposal in light of those comments. The shape of the final rule is subject to debate and may change significantly before being finalized. The Companies will continue to monitor and evaluate the impact on future plans.

New National Ambient Air Quality Standards ("NAAQS") for 8-hr Ozone and $PM_{2.5}$

8-hour Ozone

In 1997, the EPA issued the 8-hour ozone NAAQS as a replacement for the 1-hour ozone standard promulgated in 1979. The standard is designed to protect the public from exposure to ground-level ozone. Ground-level ozone is formed when emissions of NO_x and volatile organic compounds ("VOCs") react chemically in the presence of sunlight. The new standard was implemented because EPA had information demonstrating that the 1-hour ozone standard was inadequate for protecting human health.

All states were required to submit their recommended air quality designations to the EPA for the 8-hour ozone standard based on 2001, 2002 and 2003 air monitoring data. Kentucky submitted their recommendations for designations on July 14, 2003. On April 15, 2004, EPA released Phase I of the implementation rule which included designating eight counties within Kentucky as non-attainment. Those Kentucky Counties included Jefferson, Oldham, Boone, Bullitt, Kenton, Campbell, Boyd and Christian. The classifications took affect on June 15, 2004. The Companies have coal-fired electric generating units in only one of the non-attainment counties, Jefferson.

Jefferson County recently attained compliance with the 1-hour ozone standard. As a result, the county has a less prescriptive implementation scheme and is required only to comply with the more general non-attainment requirements of the CAAA. Therefore, under the 8-hour ozone standard for which the county is designated as "basic" non-attainment area, the county has until 2009 to get into attainment based on data collected in years 2006, 2007 and 2008.

The list of requirements expected of areas designated as "basic, non-attainment" are very similar to what the county followed when finally complying with the 1-hour ozone standard. With the onset of additional regulations both proposed and finalized, it is expected that Jefferson County should be able to make attainment designation by the 2009 deadline. Additionally, the Companies' requirements for NO_x reductions under the NO_x SIP Call could aid in gaining attainment status.

$PM_{2.5}$

In 1997, EPA also adopted the fine particulate NAAQS, which regulates particulate matter measuring 2.5 micrometers in diameter or smaller ("$PM_{2.5}$"). To add perspective, the diameter of a single human hair is about 20 times larger than $PM_{2.5}$ (approx. 50 micrometers). $PM_{2.5}$ is considered a threat to the public health because it has been associated with lung cancer, child development problems, and premature mortality.

In general, $PM_{2.5}$ is generated by automobiles, power plants, and industrial sources, but also includes many naturally-occurring dust-like particulates such as pollen and soot. Some $PM_{2.5}$ comes in the form of sulfates, nitrates and carbon-containing compounds. As noted previously, gaseous emissions of SO_2 and NO_x can transform into sulfates and nitrates in the atmosphere.

On February 20, 2004, the State of Kentucky submitted recommendations for non-attainment $PM_{2.5}$ designations to the EPA for Jefferson and Fayette Counties, based on data collected in 2001, 2002, and 2003. Subsequently, on June 29, 2004, EPA responded to the state's recommendation and added ten more counties to the proposed list, including Bullitt, Boone, Kenton, Campbell, Woodford, Clark, Madison, Mercer, Boyd and Lawrence. These additional counties were added by EPA because of their near proximity to the two original counties and are perceived to have an affect on the non-attainment counties. On September, 1 2004, the state responded that those additional counties should not be included in the designations. EPA released the final designations on December 17, 2004 which included Boone, Boyd, Bullitt, Campbell, Fayette, Jefferson, Kenton, part of Lawrence, and part of Mercer counties as non-attainment for $PM_{2.5}$. The final implementation rule is expected in the spring of 2005. Following that, the state will have three years to submit a revised State Implementation Plan. Depending on the severity of the designation, the state will have a compliance deadline in the range of 2010 to 2015.

Similar to the 8-hour ozone standard, these standards will lead to regulations that could impact the Companies by establishing even stricter emission standards, particularly SO_2 and NO_x. However, the application of emission control equipment required by other regulations will likely assist non-attainment areas in gaining attainment status without the need to apply even more controls on the Companies' facilities.

Regional Haze and Visibility Protection

EPA developed a regional haze regulation to protect 156 pristine (Class I) areas of the U.S., which are primarily national parks and wilderness areas. The goal of the regulatory program is to achieve natural background levels of visibility, that is, visibility unimpaired by manmade air pollutants in Class I areas, by 2064. Kentucky has one designated Class I area, Mammoth Cave National Park, and is required to assess visibility impacts to this area.

In April 1999, final regional haze regulations were issued. The final rule gives states flexibility in determining reasonable progress goals for the areas of concern, taking into account the statutory requirements of the CAAA. The final regulation will require all 50 states to reduce emissions of fine particulate matter and other air pollutants, including SO_2 and NO_x, and any other pollutant that can, via airborne transport, travel hundreds of miles and affect visibility in Class I areas. Incremental improvements of visibility in the affected areas are required to be seen early in the next decade.

In June 2001, the EPA proposed guidelines on what constituted regional haze Best Available Retrofit Technology ("BART"). The BART requirement applies to all facilities built between 1962 and 1977 that have the potential to emit more than 250 tons per year of visibility-impairing pollution. The guidelines are to be used by the states to determine how to set air pollution limits for facilities in 26 source categories, including power plants. EPA's guidance was remanded back to the agency to eliminate from the source categories those emission points whose contribution to visibility impairment is negligible. On May 5, 2004, new step-by-step guidance was published for states to implement the regional haze rule.

States will begin delivering 10-year pollution-reduction plans to the EPA following the time that areas are designated attainment or non-attainment with the $PM_{2.5}$ NAAQS. If designated attainment or "unclassifiable", states will have one year to submit implementation plans for the areas. If designated non-attainment, states will have three years to submit plans for the areas. Expectations are that these plans will have to demonstrate 15 percent reductions in air pollution each decade. States anticipate that they will be able to take credit for emission reductions under other CAAA programs.

These rules will impact the Companies by singling out coal-fired power plants as emission sources, particularly sulfates and nitrates, in need of additional controls to reduce visibility impairment in the Eastern United States.

Clean Air Interstate Rule

On December 17, 2003, The EPA proposed the "Interstate Air Quality Rule" that subsequently received a name change to the "Clean Air Interstate Rule" ("CAIR"). CAIR is a multi-pollutant strategy rule that would require significant additional reduction of SO_2 and/or NO_x emissions to further reduce levels of ozone and $PM_{2.5}$ in the atmosphere. The rule would generally apply to the eastern 25-28 states (including Kentucky) and the District of Columbia. The electric power generation sector is the only industry affected by this rule.

Implementation of the rule would be based on a "cap-and-trade" allowance program similar to the NO_x SIP Call regulation. In the case of NO_x, the EPA would allocate a predetermined amount of allowances to each state and the states would determine how to allocate these to individual units. For SO_2, current allocations under the Acid Rain Program would be used.

As proposed, CAIR would target annual SO_2 reductions of 3.6 million tons during Phase I (from 2010-2014) and an additional 2 million tons during Phase II (from 2015 and later). Because the Companies (and all other utilities impacted by CAIR) have already received their SO_2 allowances for 2010 through 2034, the EPA proposes utilities surrender allowances at a greater rate than is currently required: on a 2-for-1 and 3-for-1 basis, during Phases I and II, respectively. However, pre-2010 Acid Rain Program SO_2 allowances (i.e., banked allowances) would retain their full value. This means, to meet forecasted generation needs, additional SO_2 controls need to be investigated by KU.

For NO_x, targeted reductions for 2010 are 1.5 million tons and an additional 1.8 million tons by 2015. Additionally, emissions would begin to be counted on a year-round basis in 2010, instead of just during the ozone season. This means that controls, currently considered to be seasonal (i.e., SCRs), would have to be run year-round and may mean that additional NO_x control installation by the Companies will be necessary to meet the reduction requirements.

Comprehensive Multi-emissions Approach

Coal-fired utilities are currently faced with an uncoordinated series of emission reduction mandates. Under the Clean Air Act, the EPA has imposed multiple, often conflicting requirements to curb emissions of pollutants from power plants, which make compliance both difficult and expensive.

The electric utility industry has been working with stakeholders in Washington D.C. on a multi-emissions strategy that would streamline the current regulatory process, while accomplishing the nation's air quality goals at a fraction of the cost. This would provide greater certainty to generators in an effort to protect the nation's reliable and affordable supply of electricity.

Various initiatives have been underway to develop a multi-pollutant reduction strategy for power plant emissions—a strategy that includes clear, enforceable performance goals with the flexibility to meet them. The goal is to establish a set of agreed-upon pollutants that will be regulated and at what levels and within what timeframes. The goal is to impose emission reductions for power plants over a 10-15 year span and give utilities the flexibility to get there on their own, while knowing that the regulations will not change along the way.

The EPA and certain members of Congress have expressed support for a comprehensive, multi-pollutant approach for the power generation sector, with regulatory certainty, regulatory flexibility and "permit" relief. Numerous pieces of legislation have been introduced into

Congress to achieve this result, but most have included very punitive tonnage caps and short timetables that would force electric generators away from coal and towards gas.

In February 2002, the Bush Administration announced its Clear Skies Initiative, which addresses SO_2, NO_x, and mercury emissions reductions from electric generating facilities through an integrated and market-based cap-and-trade approach. This multi-emission plan would:

1) Cut SO_2 emissions by 73%, from 2000 emissions of 11 million tons to a cap of 4.5 million tons in 2010, and 3 million tons in 2018. (As a reference point, under current regulatory programs the electric utility industry would have been emitting 9 million tons of SO_2 in 2010.)

2) Cut NO_x emissions by 67%, from 2000 emissions of 5 million tons to a cap of 2.1 million tons in 2008, and 1.7 million tons in 2018. (As a reference point, under current regulatory programs the electric utility industry would have been emitting 3.7 million tons of NO_x in 2010.)

3) Cut mercury emissions by 69%, from 2000 emissions of 48 tons to a cap of 26 tons in 2010, and 15 tons in 2018. (For mercury, a control program is currently under development.)

While this is an aggressive program, it is achievable over time, and it is one that provides a future for coal-fired generation.

For the Companies over the next decade, Bush's Clear Skies Initiative is predicted to have the following impact:

SO_2 – Again cut the Company's emissions in half – LG&E would have to run its existing FGD harder. KU could have to install additional FGD or buy SO_2 allowances.

NO_x – The SCR retrofits that have been accomplished will aid in meeting predicted reductions. However, additional SCRs or other NO_x control equipment may be needed in the future due to load growth and increased utilization). Also, instead of operating the SCR during the ozone season, SCRs would most likely be run year-round.

Mercury – Most likely, the Company could achieve the 2010 mercury cap through conventional air pollution control equipment (FGD and SCR). However, there could be implications for certain coals with higher mercury content.

Most importantly, the Administration's approach allows for compliance on a system-wide basis through a cap-and-trade program, rather than hard-and-fast unit-by-unit emission limitations. A system-wide approach leads to more cost-effective solutions for the Companies. The adequate lead-time creates a predictable climate for long-term planning and capital investment in electric generating units, which will ensure an adequate energy supply. The 2005 session of Congress will be re-evaluating the Clear Skies Initiative. It is unclear and unpredictable what the Administration's proposal will look like, if it comes out of Congress. Some of the other proposals that Congress has reviewed had very punitive caps on these emissions and mandatory CO_2 targets that could cause a wholesale shift away from coal and toward gas. If it does not make it out of Congress, more than likely, the EPA will move forward with CAIR and the Utility Hazardous Air Pollutant Rule (mercury) as regulations to achieve similar emission reductions.

8.(5)(g) Consideration given by the utility to market forces and competition in the development of the plan.

In the development of the 2005 IRP, the Companies considered market forces and competition. This consideration is reflected in the appropriate sections of the IRP.