ODP
a PPL company

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Mr. Joel H. Peck, Clerk
Virginia State Corporation Commission
Document Control Center
1300 East Main Street
Tyler Building - First Floor
Richmond, Virginia 23219

August 29, 2013

RE: Kentucky Utilities Company d/b/a Old Dominion Power Company Electric Integrated Resource Plan Pursuant to § 56-597, 56-598 and 56-599 et seq. Code of Virginia
Case No. PUE-2013-00098

Dear Mr. Peck:

Pursuant to § 56-599(C) of the Code of Virginia, each electric utility is required to file an updated integrated resource plan ("IRP") at least every two years. In each year in which an IRP is not required, pursuant to the guidelines established by the Virginia State Corporation Commission ("Commission") in Case No. PUE-2008-00099 ("Guidelines")[1], each utility is required to file by September 1st a narrative summary describing any significant event necessitating a major revision to the most recently filed IRP, including adjustments to the type and size of resources identified.

In 2013, Kentucky Utilities Company d/b/a Old Dominion Power Company ("KU/ODP") was originally scheduled to file an IRP with the Commission. However, KU/ODP advised the Commission in the IRP administrative case that the 2013 filing would consist of a narrative summary filing, including an updated load forecast for ODP, due to KU/ODP's anticipated IRP filing in Kentucky in 2014.[2]

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[1] See *Commonwealth of Va., ex rel. State Corp. Commn., Concerning Electric Utility Integrated Resource Planning Pursuant to §§ 56-597 et seq ., of the Code of Virginia*, Case No . PUE-2008-00099, 2008 S .C .C . Ann. Rept. 606, Order Establishing Guidelines for Developing Integrated Resource Plans (Dec. 23, 2008) .

[2] See *Commonwealth of Va., ex rel. State Corp. Commn., Concerning Electric Utility Integrated Resource Planning Pursuant to §§ 56-597 et seq ., of the Code of Virginia*, Case No . PUE-2008-00099, Comments of Kentucky Utilities Company D/B/A Old Dominion Power Company (Dec. 11, 2008).

In accordance with the Guidelines, KU/ODP, hereby files an original and 15 copies of its Narrative Summary.

Please note that the Companies have not had any significant events that necessitate a major revision to the most recently filed IRP that haven't been previously reported to the Commission. In this filing, KU/ODP has three areas that warrant an update to the Commission. First, KU/ODP is currently evaluating responses to a Request for Proposal for future energy and capacity needs. Second, on March 1, 2013, KU/ODP filed an Electricity Sales Forecast Summary (Exhibit 1) as part of its Application to revise its fuel factor (Case No. PUE-2013-00019). Lastly, attached are updates (Exhibit 2) for KU that were filed with the Kentucky Public Service Commission ("KPSC") on April 5, 2013 related to an Annual Resource Assessment filing.

In April 2014, the Companies are scheduled to file a new IRP with the KPSC. KU/ODP plans to file this same IRP and the Virginia specific data requirements no later than September 1, 2014 with this Commission.

Please confirm your receipt of this filing by placing the stamp of your Office with date received on the extra copy and returning to me in the enclosed envelope. Should you have any questions regarding this information, please contact me at your convenience.

Sincerely,

Rick E. Lovekamp

Rick E. Lovekamp

c: William F. Stephens, Director of Energy Regulation (w/ enclosure)

Exhibit 1

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Old
Dominion
Power

KU/ODP Electricity Sales Forecast Summary

*July 2012**

*Updated for full-year 2012 results in January 2013

Exhibit 1
Page 1 of 8

Introduction

The production of a robust forecast of system energy requirements and peak demand is a prerequisite for efficient planning and control of utility operations. KU's goals are to provide adequate and reliable service to its customers at the lowest reasonable cost, and to achieve equitable cost allocation between customers based on the costs of providing service. Decisions on the selection, size and timing of capacity additions in the various components of the supply chain – including power plants, transmission lines, and substations – are directly dependent on sales trends and characteristics as identified in the long-term load forecast.

KU's projections of retail sales in each jurisdictional territory (KY and VA) are developed separately, using similar methodologies as described below. The forecast reviewed in this summary was finalized in July 2012.

Methodology

KU's forecasting approach is based on econometric modeling of energy sales by customer class, but also incorporates specific intelligence on the prospective energy requirements of the utility's largest customers. Econometric modeling captures the (observed) statistical relationship between energy consumption – the dependent variable – and one or more independent explanatory variables such as the number of households or the level of economic activity in the service territory. Forecasts of electricity sales are then derived from a projection of the independent variable(s).

This widely-accepted approach can readily accommodate the influences of national, regional and local (service territory) drivers of utility sales. The method may be applied, as appropriate, to forecast customer numbers, energy sales, or sales-per-customer. The statistical relationships will vary depending upon the jurisdiction being modeled and the class of service. The KU energy forecast includes three jurisdictional groups (each forecast separately): Kentucky-Retail, Virginia-Retail (ODP), and Wholesale sales (to municipal customers in Kentucky). The classes modeled include Residential, General Service, Large Power and Lighting.

The econometric models used to produce the forecast have passed two critical tests:

- the explanatory variables of the models are theoretically appropriate, statistically significant, and have been widely used in electric utility forecasting; and

- the inclusion of these explanatory variables has produced results which are intuitively reasonable.

The forecasts are based on a minimum of ten years of monthly sales history. The modeling of residential and small commercial sales also incorporates elements of end-use forecasting – covering base load, heating and cooling components of sales – which recognize expectations with regard to appliance saturation trends, efficiencies, and price or income effects.

Once complete, the KU energy forecasts are converted from a billed to calendar basis and adjusted for company uses. The resulting estimate of monthly energy sales is then associated with a class-specific load profile and load factor to generate hourly loads. These hourly loads are adjusted for losses to determine annual, seasonal, and monthly peak demand forecasts.

Data

Data inputs to the July 2012 electricity sales forecast come from a variety of external and internal sources (see Figure 1). The national outlook for U.S. Gross Domestic Product, industrial production and consumer prices are key macro-level variables that establish the broad market environment within which KU and ODP operate. National, regional and State level macroeconomic and demographic forecast data are provided by reputable economic forecasting consultants (IHS Global Insight). Weather data for each service territory is provided by the National Oceanic and Atmospheric Administration (NOAA)[1]. Lastly, important information on growth prospects is also collected directly through discussions with the Utility's largest customers.

Old Dominion Power

The Old Dominion Power Company (ODP) operating unit of Kentucky Utilities (KU) serves five counties in southwestern Virginia. As these sales occur in the Virginia jurisdiction, they are modeled separately from sales to other KU customers. The ODP sales forecast is disaggregated on a rate class basis, including Residential, General Service, Large Power, and Lighting rate classes. The following tables display the actual and forecast sales structure of KU as a whole and of the ODP service territory. Table 1 shows actual KU sales by jurisdiction (Kentucky Retail, Kentucky Wholesale and Virginia Retail) over the period 2010-2012. Table 2 shows

[1] Sales forecasts assume 'normal' weather based on a twenty-year series of historic heating degree-day and cooling degree-day data.

forecasted KU sales by jurisdiction, and Table 3 shows forecasted Virginia sales by class, both for the period 2013-2014.

Table 1: KU Calendar Actual Sales by Jurisdiction (GWh)*

	2010	2011	2012[2]
Kentucky Retail	18,974	18,320	18,209
Kentucky Wholesale	2,002	1,906	1,886
Virginia Retail	962	936	861
Total System	21,938	21,162	20,956

* not adjusted for deviations from normal weather

Table 2: KU Calendar Forecast Sales by Jurisdiction (GWh)*

	2013	2014
Kentucky Retail	18,600	18,677
Kentucky Wholesale	1,944	1,961
Virginia Retail	948	953
Total System	21,492	21,591

Table 3: ODP Calendar Forecast Sales by Class (GWh)*

	2013	2014
Residential	396	390
Schools	25	25
General Service	103	105
Large Power	416	426
Lighting	7	7
Municipal Pumping	1	1
Total System	948	953

* sum of class values may not match total due to rounding

The following sections of this report review the methodology employed in developing the ODP sales forecast, by class of consumption.

ODP Residential Forecast

The ODP residential forecast includes all customers on the residential service (RS) rate schedule. The forecast for residential sales was computed as the product of a use-per-customer forecast and a forecast of the number of customers. The number of ODP residential customers was forecasted

[2] Temperature abnormalities in the 2012 heating season and historically low gas prices in the second half of 2012 were beyond the scope of established sensitivities modeled in the forecast, and resulted in greater differences between actual and forecasted values than are typically experienced without such conditions.

as a function of the number of households in the ODP service territory. Household data was provided by IHS Global Insight.

Residential Statistically-Adjusted End-Use (SAE) Model

The residential use-per-customer forecast employed a Statistically-Adjusted End-Use (SAE) methodology. This approach combines an econometric model – relating monthly sales to various explanatory variables such as weather and economic conditions – with traditional end-use modeling. The SAE approach defines household electricity consumption as a function of the use of heating equipment (XHeat), cooling equipment (XCool), and other equipment (XOther).

$$\text{Electricity Sales-per-Customer} = a_1{*}XHeat + a_2{*}XCool + a_3{*}XOther$$

Heating use is dependent upon weather conditions (measured in heating degree days), heating equipment efficiencies and saturation levels, home size and construction characteristics, household size and income level, and energy prices. The heating component of residential consumption is calculated as the product of an annual equipment index and a usage multiplier:

$$XHeat_y = HeatIndex_y * HeatUse_y$$

Where:

$XHeat_y$ = Estimated heating energy use for the year

$HeatIndex_y$ = Annual index of heating equipment

$HeatUse_y$ = Annual usage multiplier

The Heat Index variable represents a weighted average across multiple types of equipment saturation levels adjusted for differences in appliance efficiency levels. Heating equipment includes heat pumps, electric space heating, and electric furnaces. The Heat Use variable (multiplier) is impacted by changes in the following exogenous variables: heating degree-days, household size, household income, and the price of electricity.

Cooling use is likewise dependent upon weather conditions (cooling degree-days in the summer period), the market saturation of cooling equipment, and the efficiency of such appliances, as well as on household size, household income, and the price of electricity. The cooling component of residential consumption is calculated – as for the heating component - as the product of an annual equipment index and a usage multiplier:

$$XCool_y = CoolIndex_y * CoolUse_y$$

Where:

$XCool_y$ = Estimated cooling energy use for the year

$CoolIndex_y$ = Annual index of cooling equipment

$CoolUse_y$ = Annual usage multiplier

Cooling equipment includes heat pumps, room air conditioners, and central air conditioners.

Other use is dependent on trends in appliance saturations, household size and income levels, and the price of electricity.

ODP General Service Forecast

The ODP General Service forecast includes customers on the General Service rate schedule. ODP General Service sales were also computed as the product of separate forecasts of use-per-customer and the number of customers. Use-per-customer was forecasted as an end-use model incorporating heating, cooling and other equipment by type of commercial business. The number of customers was forecasted as a function of the number of residential customers.

ODP Large Power Forecast

The ODP Large Power forecast includes customers on the Large Power service rate schedules, which include Power Service Primary and Secondary, Time-of-Day Primary and Secondary, and Retail Transmission Service. Large Power sales were forecasted as a function of economic indicators, weather and binary variables.

ODP Schools Forecast

The ODP Schools forecast includes all customers on the "school service (SS)" rate schedule. Sales were modeled as a function of the number of households and weather.

ODP Lighting Forecast

The ODP lighting forecasts were forecasted using trending models.

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Energy Requirements Forecast

Since customers are billed on a billing-period basis (rather than a calendar-month basis), energy sales forecasts are first generated on a billing-period basis. To determine system energy requirements, (i) each energy forecast is converted from a billing-period basis to a calendar-month basis and (ii) the aggregate calendar-month forecast is adjusted for transmission and distribution losses. In the 'billed-to-calendar' conversion process, the weather-related components for a given forecast model and billing month are allocated to calendar months based on the distribution of degree days in the billing month to calendar months. The non-weather-related components are allocated to calendar months based on the distribution of calendar days in the billing month to calendar months.

Figure 1 – Load Forecast Process

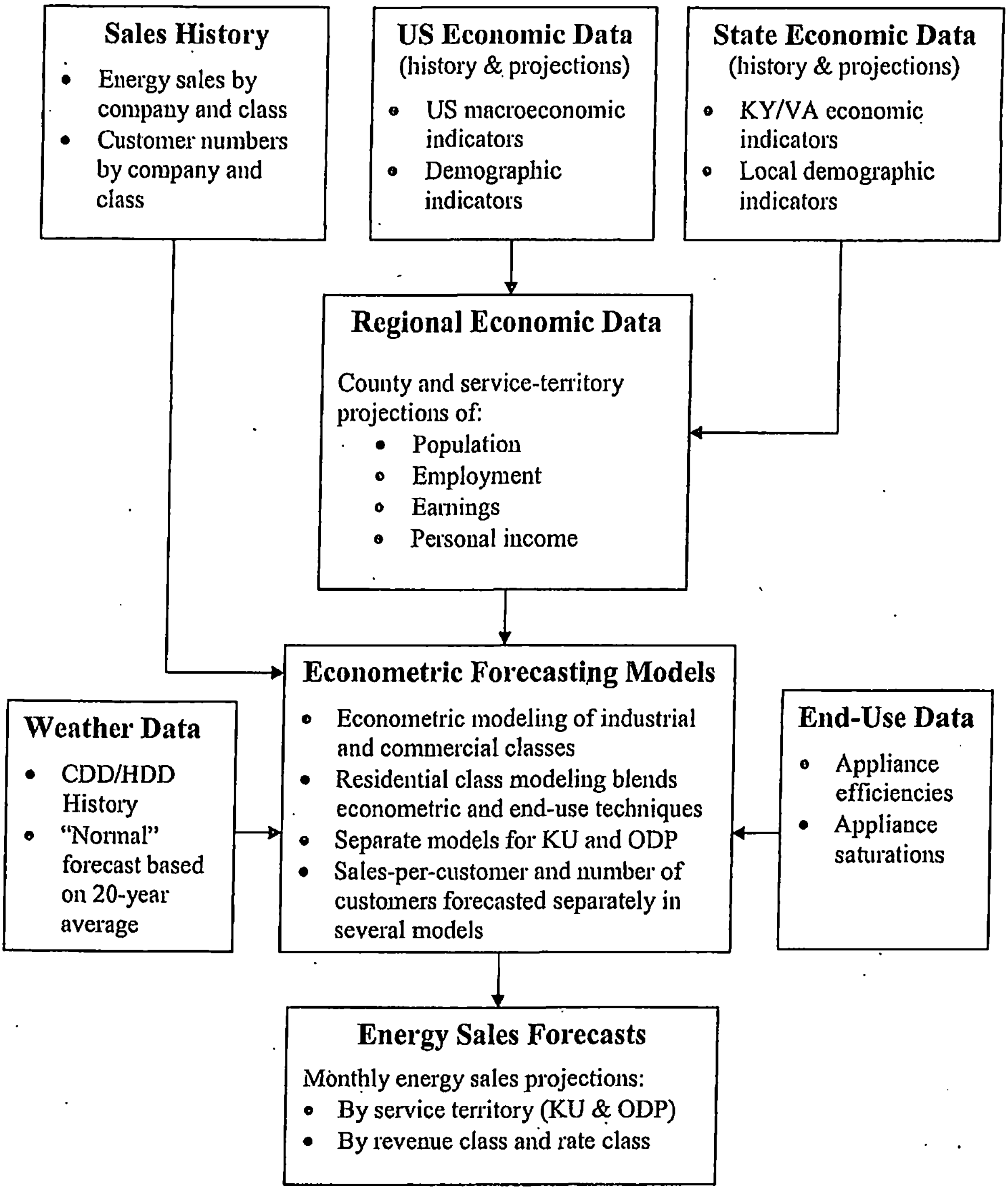

Exhibit 2

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KENTUCKY UTILITIES COMPANY

2012 ANNUAL RESOURCE ASSESSMENT FILING
PURSUANT TO APPENDIX G OF THE COMMISSION'S ORDER
DATED DECEMBER 20, 2001, IN ADMINISTRATIVE CASE NO. 387
AS AMENDED BY THE COMMISSION'S ORDER DATED MARCH 29, 2004
FILED APRIL 2013

ITEM NO. 3

RESPONDENT: Greg Lawson/Stuart Wilson

3. Actual and weather-normalized monthly coincident peak demands for the just completed calendar year. Demands should be disaggregated into (a) native load demand (firm and non-firm) and (b) off-system demand (firm and non-firm).

Response:

Please refer to the attached Table KU-3, which shows the actual and weather-normalized native KU peak demands. The normalized native KU stand-alone peak demands are available only on a seasonal (summer/winter) basis.

TABLE KU-3
NATIVE AND OFF-SYSTEM DEMANDS BY MONTH FOR 2012

Kentucky Utilities

	Actual			Normal Weather (Seasonal)	Off-System (1)		
Time of Monthly Native Peak	Native Peak	Non-Firm	Firm	Native Peak	Firm	Non-Firm	Total
1/13/2012 10:00	4,014	81	3,933	4,177	0	203	203
2/13/2012 8:00	3,825	66	3,759		0	2	2
3/6/2012 8:00	3,366	90	3,276		0	100	100
4/30/2012 15:00	3,014	109	2,905		0	150	150
5/25/2012 17:00	3,482	94	3,388		0	0	0
6/29/2012 16:00	4,138	96	4,042	3966	0	0	0
7/25/2012 15:00	4,088	34	4,054		0	0	0
8/8/2012 16:00	3,999	82	3,917		0	0	0
9/5/2012 14:00	3,770	89	3,681		0	0	0
10/30/2012 19:00	2,996	108	2,888		0	0	0
11/29/2012 8:00	3,464	19	3,445		0	0	0
12/12/2012 8:00	3,605	77	3,528		0	1	1

Notes

(1) The allocation of off-system sales split between LG&E and KU is handled in the After-the-Fact Billing ("AFB") process in accordance with the Power Supply System Agreement between LG&E and KU. The individual company sales will include an allocation of the sales sourced with purchased power and allocated to the individual company based on each company's contribution to off-system sales.

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ITEM NO. 4

RESPONDENT: Greg Lawson

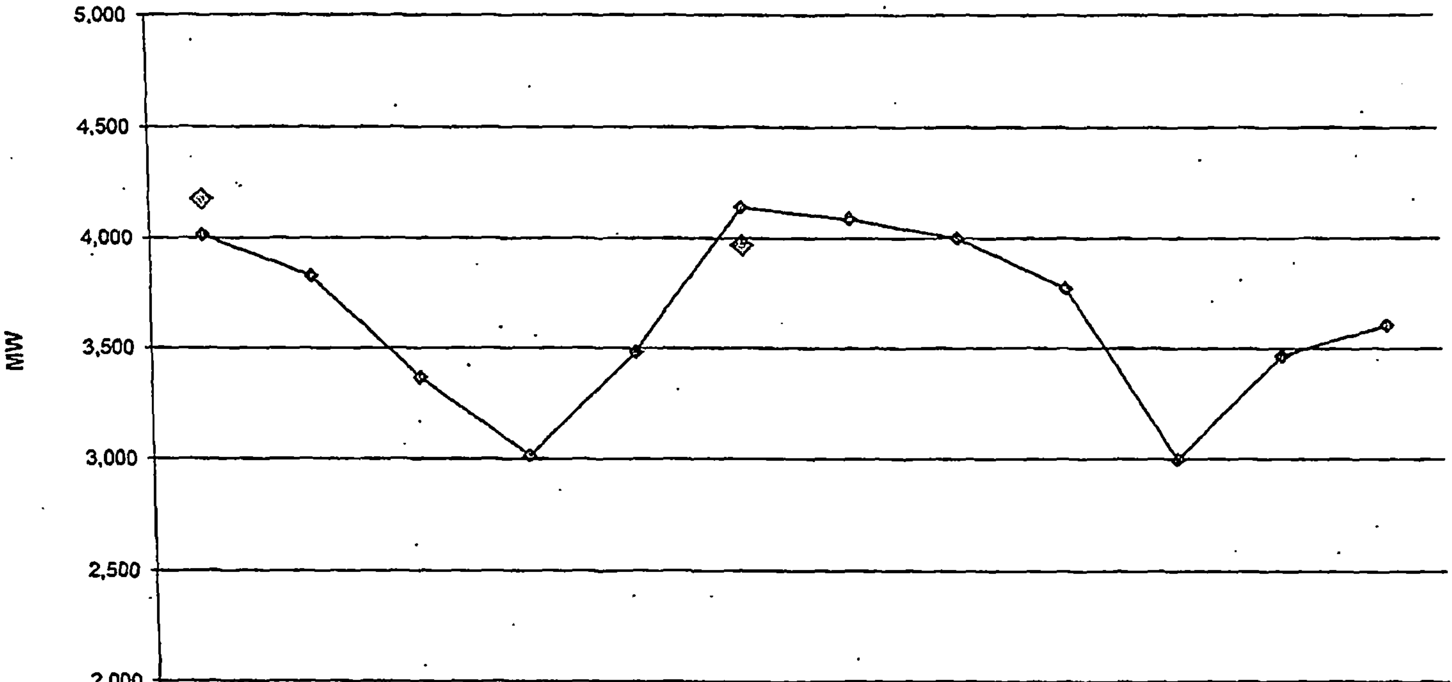
4. Load shape curves that show actual peak demands and weather-normalized peak demands (native load demand and total demand) on a monthly basis for the just completed calendar year.

Response:

Please refer to the attached Figure KU-4.

Figure KU-4

KU 2012
Actual and Weather Normalized Seasonal Peak



	1	2	3	4	5	6	7	8	9	10	11	12
Actual	4,014	3,825	3,366	3,014	3,482	4,138	4,088	3,999	3,770	2,996	3,464	3,605
WN	4,177					3,966						

Month

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ITEM NO. 6

RESPONDENT: Greg Lawson/Stuart Wilson

6. Based on the most recent demand forecast, the base case demand and energy forecasts and high case demand and energy forecasts for the current year and the following four years. The information should be disaggregated into (a) native load (firm and non-firm demand) and (b) off-system load (both firm and non-firm demand).

Response:

a) Please see the attached Table KU-6a. The values in Table KU-6a reflect the impact of the Companies' Energy Efficiency programs.

b) Off-system sales ("OSS") projections for 2013-2017 contained in the attached Table KU-6b are based on the combined Companies' current plan. For OSS, only base case total sales energy projections exist for 2013-2017. The projections consist of the expected market sales, dubbed "Wholesale OSS". All OSS are non-firm.

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Table KU-6a

Kentucky Utilities	2013	2014	2015	2016	2017
Base Case Energy Sales (GWh)	21,491	21,591	21,686	21,767	21,836
High Case Energy Sales (GWh)	22,631	22,739	22,847	22,944	23,029
Base Case Energy Requirements (GWh)	22,823	22,930	23,031	23,110	23,187
High Case Energy Requirements (GWh)	24,033	24,150	24,264	24,360	24,454
Base Case Native Peak Demand (MW)	4,229	4,255	4,276	4,293	4,316
High Case Native Peak Demand (MW)	4,454	4,482	4,505	4,525	4,552

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Table KU-6b
Total Base Case Off-System Sales Energy Projection

	2013	2014	2015	2016	2017
Existing OSS (GWH)	0	0	0	0	0
Wholesale OSS (GWH)	465	385	194	196	133
Total OSS (GWH)	465	385	194	196	133

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KENTUCKY UTILITIES COMPANY
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ITEM NO. 7

RESPONDENT: **Stuart Wilson**

7. The target reserve margin currently used for planning purposes, stated as a percentage of demand. If changed from what was in use in 2001, include a detailed explanation for the change.

Response:

As part of the 2011 Integrated Resource Plan ("2011 IRP"), the Companies established an optimal reserve margin range of 15% to 17%, with 16% recommended for planning purposes. The range provides an optimum level of reliability through various system operating conditions. The 2011 IRP was filed with the Commission in April 2011.

The Companies utilized a planning reserve margin target of 12% in 2001 and 14% in 2002 based on a reserve margin range of 11%-14% established in the Companies' 1999 IRP. A detailed explanation of the current target reserve margin is documented in the report titled "LG&E and KU 2011 Reserve Margin Study" included in Volume III of the Companies' 2011 IRP.

KENTUCKY UTILITIES COMPANY

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ITEM NO. 8

RESPONDENT: Stuart Wilson

8. Projected reserve margins stated in megawatts and as a percentage of demand for the current year and the following 4 years. Identify projected deficits and current plans for addressing these. For each year identify the level of firm capacity purchases projected to meet native load demand.

Response:

Please refer to the attached Table KU-8. In Table KU-8, Brown Units 1 and 2 are assumed to be retrofitted with environmental controls and continue to operate beyond 2015. The Companies are currently evaluating responses to an RFP for meeting their future energy and capacity needs. The decision to retire or retrofit Brown 1-2 is being revisited in the context of this analysis.

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Table KU-8
Combined Company
Reserve Margin Needs (MW)

Current Values	2013	2014	2015	2016	2017
Peak Load	7,259	7,339	7,426	7,509	7,597
DSM at Peak Hour	-307	-344	-386	-418	-450
CSR/Interrupt	-131	-134	-137	-137	-137
Net Load*	6,821	6,860	6,903	6,954	7,010
Existing Capability	7,936	7,949	7,174	7,162	7,179
New Capacity	0	0	640	640	640
OVEC	155	152	152	152	152
Total Supply	8,091	8,101	7,966	7,954	7,971
MW Margin	1,270	1,241	1,063	999	961
Reserve Margin %	18.6%	18.1%	15.4%	14.4%	13.7%
Capacity Need for 16%	(178)	(143)	42	113	161

*Sum of individual values may not match totals due to rounding.

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KENTUCKY UTILITIES COMPANY

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ITEM NO. 12

RESPONDENT: Stuart Wilson

12. Identify all planned base load or peaking capacity additions to meet native load requirements over the next 10 years. Show the expected in-service date, size and site for all planned additions. Include additions planned by the utility, as well as those by affiliates, if constructed in Kentucky or intended to meet load in Kentucky.

Response:

Please refer to the attached Table KU-12. The Companies are currently evaluating responses to an RFP for meeting their future energy and capacity needs. The decision to retire or retrofit Brown Units 1 and 2 is being revisited in the context of this analysis. The planned capacity additions that result from this analysis may differ from the planned capacity additions presented in Table KU-12.

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Table KU-12
Planned Capacity Additions (2013-2022)

In Service/ Acquisition Date	Type	Site	Summer Net Capacity (MW)	Winter Net Capacity (MW)
May 2015	2x1 Combined Cycle Combustion Turbine	Cane Run (Jefferson Co, KY)	640	693
June 2018	2x1 Combined Cycle Combustion Turbine	Undecided	605	651

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KENTUCKY UTILITIES COMPANY

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ITEM NO. 13

RESPONDENT: Derek Rahn

13. The following transmission energy data for the just completed calendar year and the forecast for the current year and the following four years:

a. Total energy received from all interconnections and generation sources connected to the transmission system.

b. Total energy delivered to all interconnections on the transmission system.

c. Peak load capacity of the transmission system.

d. Peak demand for summer and winter seasons on the transmission system.

Response:

Data exists for 2012. The Company does not forecast this type of data; therefore no forecast exists for 2012-2015.

a. LG&E and KU operate as a single NERC Control area that contains several generators not owned by LG&E and KU; the non-Company owned facilities are also included as sources below:

Tie Lines Received (MWH)	16,185,232
Net Generation-LG&E (MWH)	16,202,899
Net Generation-KU (MWH)	19,067,373
Net Received from OMU (MWH)	2,532,319
Net Generation-IPPs (MWH)	56,783
Total Sources (MWH)	54,044,606

b. LG&E and KU operate as a single Control Area, the amount of energy delivered at the interconnections of the single Control area were 17,751,898 MWH(s).

c. There is no set number for peak load capacity for the transmission system. The system is built to support Network Service and firm PTP customers as tested under the LGE/KU Transmission Planning Guidelines. Actual transmission capacity available for Network customers, import, export or thru-flow will vary depending on which facilities (generation, load or transmission) in the interconnected transmission system of the eastern interconnect are connected and operated at any given time.

d. The maximum summer peak transmission load for the combined LG&E/KU transmission system was 7223 MW for the peak hour of 6/29/12 at 4PM.

The maximum winter peak transmission load for the combined LG&E/KU transmission system was 5926 MW for the peak hour of 1/13/12 at 10AM.