STITES & HARBISON PLLC

ATTORNEYS

421 West Main Street
Post Office Box 634
Frankfort, KY 40602-0634
[502] 223-3477
[502] 223-4124 Fax
www.stites.com

August 17, 2005

RECEIVED
AUG 17 2005
PUBLIC SERVICE COMMISSION

Mark R. Overstreet
(502) 209-1219
(502) 223-4387 FAX
moverstreet@stites.com

HAND DELIVERED

Beth O' Donnell
Executive Director
Public Service Commission
211 Sower Boulevard
Frankfort, KY 40601

Re: P.S.C. Case No. 2005-00101

Dear Ms. O'Donnell:

Enclosed please find and accept for filing an original and five copies of Kentucky Power Company's Responses to the Commission's Data Requests.

Please do not hesitate to contact me if you have any questions.

Sincerely yours,

STITES & HARBISON, PLLC

Mark R. Overstreet

KE057:KE180:12921:1:FRANKFORT

RECEIVED
AUG 17 2005
PUBLIC SERVICE COMMISSION

COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF

THE APPLICATION OF KENTUCKY POWER COMPANY	)	
FOR A CERTIFICATE OF PUBLIC CONVENIENCE AND	)	
NECESSITY TO CONSTRUCT A 161KV TRANSMISSION	)	CASE NO. 2005-00101
LINE IN LESLIE COUNTY, KENTUCKY	)	

KENTUCKY POWER COMPANY RESPONSE TO

COMMISSION STAFF'S FIRST SET DATA REQUEST

August 17, 2005

Kentucky Power Company

REQUEST

Provide a description of the transmission planning process and reliability testing criteria utilized by Kentucky Power or American Electric Power ("AEP").

RESPONSE

As part of the transmission planning process, AEP develops expansion plans for the local systems to ensure reliability. AEP's entry into PJM on October 1, 2004 did not fundamentally change the planning process for the local areas of the AEP East transmission system. However, FERC Order 2000 requires RTOs to implement a stakeholder-driven open regional planning process to develop an expansion plan for the bulk transmission system within its footprint. PJM, in cooperation with the stakeholders, undertakes this task and develops the PJM Regional Transmission Expansion Plan (RTEP) on an annual basis. AEP participates fully in that process as a stakeholder.

AEP and PJM coordinate the planning activities on a "bottoms up/top down" approach. AEP plans and develops expansion plans for the load areas of the AEP transmission system to meet the applicable reliability criteria. PJM consolidates AEP's expansion plans with those of other PJM member utilities and then collectively evaluates the expansion plans as part of the RTEP process. The PJM assessment is to ensure consistent and coordinated expansion of the overall bulk transmission system within its footprint. In accordance with this process, AEP continues to be responsible for the planning of its local system and will coordinate the expansion of the AEP EHV System with the PJM Stakeholders through the PJM RTEP process.

By way of the PJM RTEP process, the transmission expansion plans for the bulk transmission system are developed for the entire RTO footprint via a single regional planning process, assuring a consistent view of needs and expansion timing while minimizing expenditures. The RTEP process is designed to identify bulk transmission system requirements for the PJM footprint. PJM then determines the individual member's responsibility as related to construction and costs to implement this stakeholder transmission expansion plan. This process identifies the most appropriate, reliable and economical integrated transmission reinforcement plan for the entire region while blending the local expertise with a regional view and formalized open stakeholder input.

AEP's planning criteria is consistent with the NERC Planning Standards and ECAR Document 1. Consequently, expansion of the AEP transmission system resulting from the PJM RTEP process will also be consistent with the NERC Planning Standards, ECAR Documents, as well as the specific AEP criteria. The AEP planning criteria are filed with FERC annually as part of AEP's FERC Form 715 filing. Using these criteria, limitations, constraints and future potential deficiencies on the AEP transmission system are identified. Remedies are identified and budgeted as appropriate to ensure that system enhancements will be timed to address the anticipated deficiency.

Kentucky Power Company

REQUEST

Provide a description the volt/VAR Control issues and any planned implementations of new technologies, such as FACTS technologies.

RESPONSE

Transmission System serving Kentucky Power's Hazard area includes shunt capacitors installed at several stations. In addition to these mechanically controlled shunt capacitor banks, Beaver Creek Static Var Compensator (SVC) provides dynamic voltage control in the area. In addition, a capacitor bank connected in a bridge configuration (connected between 161 kV and 69 kV) also provide the needed volt/VAR Control and support to the Hazard area.

Kentucky Power has implemented new technologies as required. Beaver Creek SVC was part of such effort. During late 1990's a FACTS device was installed just north of the Hazard area at Kentucky Power's Inez Station.

Kentucky Power Company

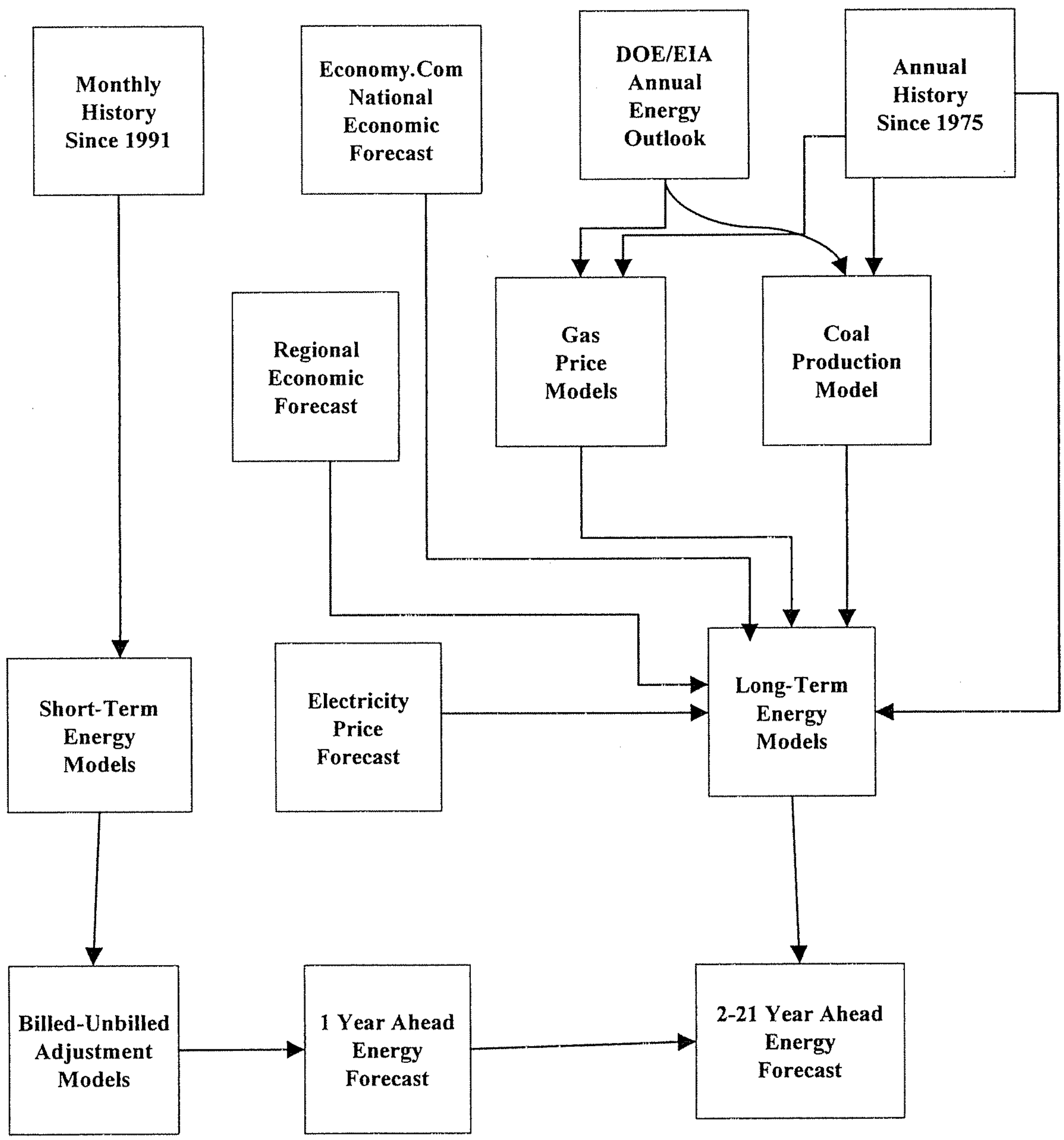
REQUEST

Provide a description of AEP's load forecasting process and a summary of the historical and forecasted system loads.

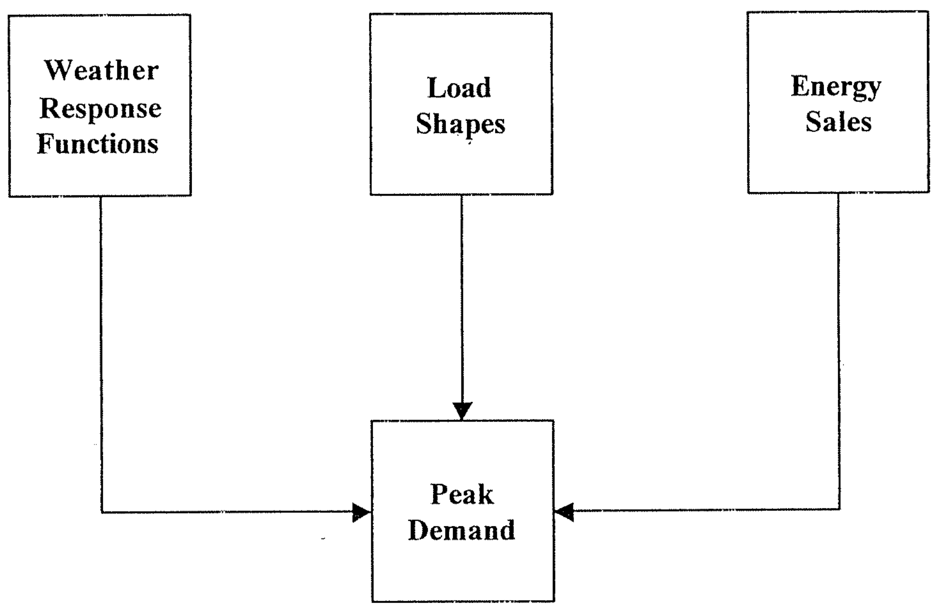
RESPONSE

Please see the attached pages.

Kentucky Power Company
Internal Energy Requirements Forecasting Method



Kentucky Power Company
Peak Internal Demand



Kentucky Power Company
Area Load Forecast

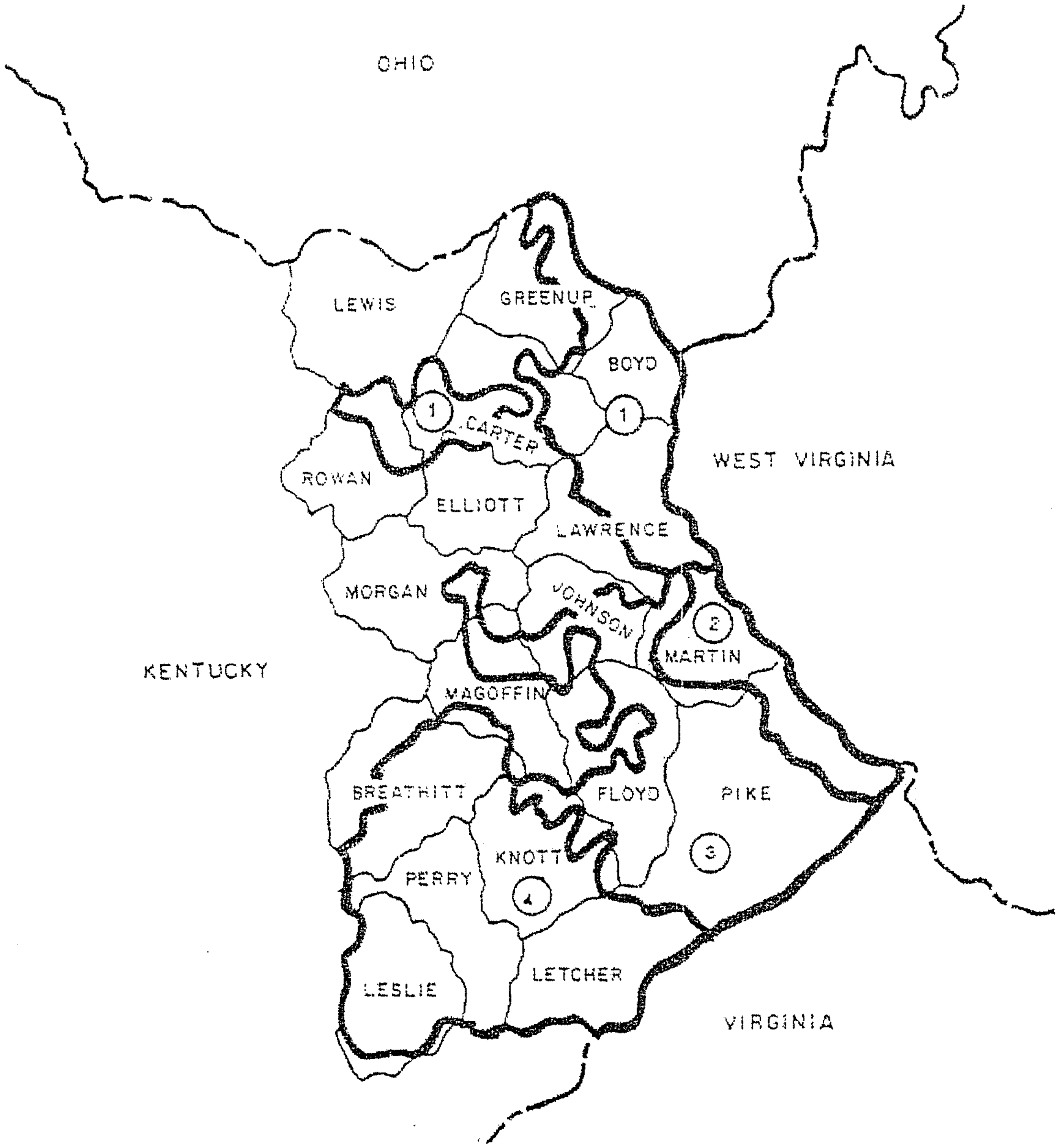
Areas Forecast
Ashland
Hazard
Pikeville
Sprigg

Area Forecast Reconiciled with Company Forecast

Adjustment includes accounting for losses

One in Five Year Forecast Devloped for High and Low Scenarios

KENTUCKY POWER COMPANY
REGIONAL LOAD AREAS



1. ASHLAND
2. DEWEY-SPRIGG KY.
3. PIKEVILLE
4. HAZARD

2. LOAD FORECAST

2. LOAD FORECAST

A. SUMMARY OF LOAD FORECAST

A.1. Forecast Assumptions

The load forecasts for KPCO and the other operating companies in the AEP System are based on a forecast of U.S. economic growth provided by Economy.com (formerly RFA). The load forecasts presented herein are based on an Economy.com economic forecast issued in June 2002 and on AEP load experience prior to 2002. Economy.com projects moderate growth in the U.S. economy during the 2002-2016 forecast period, characterized by a 2.9% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the consumer price index expected to rise by 2.3% per year. Industrial output, as measured by the Federal Reserve Board's (FRB's) index of industrial production, is expected to grow at 2.7% per year during the same period. For the regional economic outlook, the June 2002 forecast developed by Economy.com was utilized. The outlook for KPCO's service area projects employment growth of 1.4% per year during the forecast period and real regional income per-capita growth of 1.8%.

Inherent in the load forecasts are the impacts of past customer energy conservation and load management activities, including company-sponsored demand-side management (DSM) programs already implemented. The load impacts of future, or expanded, DSM programs are analyzed and projected separately, and appropriate adjustments applied to the load forecasts.

A.2. Forecast Highlights

KPCO's total internal energy requirements, before consideration of the effects of expanded DSM programs, are forecasted to increase at an average annual rate of 1.6% from 2002 to 2016. The corresponding summer and winter peak internal demands are forecasted to grow at an average annual rate of 1.7%. KPCO's annual peak demand is expected to continue to occur in the winter season.

The Regulated AEP-East's internal energy requirements during the forecast period are projected to increase at an average annual rate of 1.7% between 2003 and 2016, before consideration of the effects of expanded DSM. Summer and winter peak internal demands are expected to grow at average annual rates of 1.7% and 1.6%, respectively. The Regulated AEP-East annual peak is projected to occur in the winter season.

The load effects of expanded DSM generally increase in time through about the year 2006 and remain relatively stable until about 2016, diminishing thereafter. Over the 20-year forecast period, the projected expanded DSM has little effect on load growth. For both the Regulated AEP-East and KPCO, the expected annual rate of growth in internal energy requirements, as well as in the summer and winter peak internal demands, after accounting for expanded DSM, is unchanged from the growth rate without DSM.

B. OVERVIEW OF FORECAST METHODOLOGY

The Company's load forecasts are based mostly on econometric analyses of time-series data. This method has much to recommend it for load forecasting. One advantage is that it provides a relatively efficient means of producing an internally consistent forecast. This consistency is enforced by the necessity that the model logic be specified in mathematical terms and that all forecast assumptions be defined in quantifiable terms. Another advantage is that it is readily amenable to the consideration of alternate futures through the use of scenario analysis or the development of confidence bands. A third advantage of econometric analysis is that it lends itself to objective verification of models through the application of standard statistical criteria. This aspect is particularly useful in that it facilitates comparisons of forecasting models across companies and across successive forecasts.

In practice, econometric analysis as a general method covers a wide range of specific techniques, and thus raises the issue of choice among alternatives in building and estimating forecasting models. Many of these choices are not obvious and can only be resolved through professional judgment. A similar role for professional judgment also exists in the interpretation of the statistical criteria used to judge the performance of the econometric models, which are, likewise, not always clear-cut. In the development of the Company's load forecast, such judgment is informed by a guiding principle, which is to produce as useful and as accurate a forecast as possible, within the constraints imposed by corporate resources and by the availability of data.

In pursuit of that principle, the Company's energy requirements forecast is derived from two sets of econometric models, i.e., a set of monthly short-term models and a set of annual long-term models. This procedure permits easier adaptation of the forecast to the various short- and long-term planning purposes that it serves. For the first full year of the forecast, the forecast values are governed exclusively by the short-term models. The short term models use billed or metered energy sales. The output from the short-term models are adjusted to be unbilled energy sales, which are consistent with the energy generated. The unbilled energy sales forecast is the short-term forecast. For the remaining years of the forecast (2004-2016), the forecast values are determined utilizing the annual growth rates from the long-term models and applying those to the 2003 short-term forecast.

In both sets of models, the major energy classes are analyzed separately. Inputs such as regional and national economic and demographic conditions, energy prices, weather factors, special information (for example, the known plans of specific major customers) and informed judgment are all utilized in producing the forecasts. The major difference between the two sets of models is that the short-term models utilize mostly trend, seasonal and weather variables, while the long-term models utilize "structural" variables, such as per-capita income, employment, energy prices and weather factors, as well as trend variables. Supporting forecasting models are used to predict the future levels of some of the inputs to the long-term energy models. For example, natural gas and coal models are used to predict sectoral natural gas prices and regional coal production. These forecasts then serve as inputs to the respective long-term energy forecasts.

The energy forecast for the total AEP System, by customer class, is obtained by summing the forecasts, by customer class, of each of the AEP operating companies.

The forecast of peak internal demand for the Company is produced by using an analysis similar to EPRI's Hourly Electric Load Model (HELM) that estimates hourly demand based on energy sales forecast, load shapes and weather response functions (WRF). The use of forecasted energy requirements in the peak demand models ensures consistency between the Company's peak demand and energy requirements forecasts.

The forecast of peak internal demand for the Regulated AEP-East is determined by summing the operating company hourly demand forecasts.

Flow charts depicting the structure of the models used in projecting KPCO's electric load requirements are shown in Exhibits 2-1 and 2-2. Page 1 of Exhibit 2-1 depicts the stages in the development of the Company's short-term and long-term internal energy requirements forecasts. Page 2 of Exhibit 2-1 identifies in greater detail the variables included in the short-term and long-term energy requirements forecasting models. Exhibit 2-2 presents a schematic of the peak internal demand forecasting model. Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendix.

C. FORECAST METHODOLOGY FOR INTERNAL ENERGY REQUIREMENTS

C.1. General

This section provides a detailed description of the short-term and long-term models employed in producing the forecasts of energy consumption, by customer class, for KPCO. For the purposes of the Company's load forecast, the short term is defined as the first full year of the forecast period, and the long term as anything beyond that.

Conceptually, the difference between the short term and the long term, as it concerns electric energy consumption, has to do with the changes in the stock of electricity-using equipment, rather than with the passage of time. The short term covers the time period during which changes in this stock are minimal, and the long term as the time period during which changes in this stock can be significant. In practice, changes in equipment stocks are related to the passage of time.

In the short term, electric energy consumption is considered to be a function of the utilization of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing utilization in the short term is weather. For industrial customers, economic forces that determine inventory levels and factory orders also influence short-term utilization rates. The short-term forecasting models recognize these relationships and use weather and the recent trend in load growth, as the primary explanatory variables in forecasting monthly energy sales up to 18 months ahead.

Over time, demographic and economic factors, such as population, employment and income, as well as technology, determine the nature of the stock of electricity-using equipment, in both its size and composition. The long-term forecasting models recognize the importance of these variables and include most of them in the formulation of the long-term energy forecasts.

Relative energy prices also have an impact on electricity consumption. One important difference between the short-term and long-term forecasting models is their treatment of energy prices. Energy prices are not included in the short-term models, but are included in the long-term models. This treatment is justified by consideration of the nature of technological and behavioral constraints on consumer response to price changes. In the short term, these constraints are severe. The presence of durable equipment stocks and the formation of price expectations based in part on past prices mitigates the short-term effect of price changes. In the long term, however, these constraints are lessened as durable equipment is replaced and as price expectations come to fully reflect price changes.

C.2. Short-term Forecasting Models

The goal of KPCO's short-term forecasting models is to produce an accurate load forecast for the first full year into the future. To that end, the short-term forecasting models generally employ a combination of monthly and seasonal binaries, time trends, and monthly heating cooling degree-days in their formulation. The heating and cooling degree-days are measured at weather stations in the Company's service area.

The short-term forecasts were developed utilizing a set of autoregressive integrated moving average (ARIMA) models, which incorporated weather variations. The ARIMA models utilized heating and cooling degree-days and binary variables in the model development. These models were utilized to forecast all sectors.

The estimation period for the short-term models was January 1991 through April 2002.

C.2.a. Residential and Commercial Energy Sales

Residential and commercial energy sales are developed using ARIMA models to forecast usage per customer and number of customers. The usage models relate usage to lagged usage, lagged error terms, heating and cooling degree-days and binary variables. The customer models relate customers to lagged customers, lagged error terms and binary variables. The energy sales forecasts are a product of the usage and customer forecasts.

C.2.b. Industrial Energy Sales

The short term industrial energy sales model for KPCO relates energy sales to lagged energy sales, lagged error terms and binary variables. The industrial model is estimated using an ARIMA model.

C.2.c. All Other Energy Sales

The All Other Energy Sales category for KPCO includes public street and highway lighting (or other retail sales) and sales to municipals. KPCO's municipal customers include the cities of Vanceburg and Olive Hill.

Both the other retail and municipal models are estimated using ARIMA models. KPCO's short-term forecasting model for public street and highway lighting energy sales includes binaries, and lagged energy sales. The sales-for-resale model includes binaries, heating and cooling degree days, lagged error terms and lagged energy sales.

C.2.d. Losses and Unaccounted-For Energy

The forecast losses for KPCO are based on an analysis of the historical relationship between energy sales and generation.

C.2.e. Billed/Unbilled Analysis

Unbilled energy sales are forecast using a simple autoregressive model. Estimated gross monthly unbilled energy sales divided by billed energy sales acts as the independent variable. This value, a percentage, is a positive value, which under a hypothetical normal weather scenario, should be about 40%. However, weather and other bookkeeping events cause the percentage to vary. Since the Company forecasts normal weather, the explanatory variables were chosen to estimate average or normal relationships. This was achieved utilizing monthly binary variables. Thus, the implication is that for a particular month, the gross unbilled energy sales is a given percentage of the normal billed energy sales.

The resulting forecast percentage of gross unbilled divided by billed energy is multiplied by the forecast of billed energy sales. Then, mathematical calculations that mirror the computation of net unbilled energy sales are performed resulting in forecast net unbilled energy sales.

C.3. Long-term Forecasting Models

The goal of the long-term forecasting models is to produce a reasonable load outlook for up to 20 years in the future. Given that goal, the long-term forecasting models employ a full range of structural economic and demographic variables, electricity and natural gas prices, weather, as measured by annual heating and cooling degree-days, and binary variables to produce load forecasts conditioned on the outlook for the U.S. economy, for the Company's service-area economy, and for relative energy prices.

Most of the explanatory variables enter the long-term forecasting models in a straightforward, untransformed manner. In the case of energy prices, however, it is assumed, consistent with economic theory, that the consumption of electricity responds to changes in the price of electricity or substitute fuels with a lag, rather than instantaneously. This lag occurs for reasons having to do with the technical feasibility of quickly changing the level of electricity use even after its relative price has changed, or with the widely accepted belief that consumers make their consumption decisions on the basis of expected prices, which may be perceived as functions of both past and current prices.

The estimation period for the long-term load forecasting models was 1975-2001. The long-term energy sales forecast is developed by applying the growth rates from the long-term models to the unbilled energy sales forecasts for 2003.

C.3.a. Supporting Models

In order to produce forecasts of certain independent variables used in the internal energy requirements forecasting models, several supporting models are used, including a natural gas price model and a regional coal production model for the KPCO service area. These models are discussed below.

C.3.a.1. Natural Gas Price Model

The forecast price of natural gas used in the Company's energy models comes from a model of state natural gas prices for four primary consuming sectors: residential, commercial, industrial and electric utilities. In the state natural gas price models sectoral prices are related to U.S. sectoral prices, as well as binary variables. The U.S. natural gas price forecasts were obtained from U.S. DOE/EIA's "2002 Annual Energy Outlook". The estimation interval for the natural gas price model, which is an annual model, was 1973-2001.

C.3.a.2. Regional Coal Production Model

A regional coal production forecast is used as an input in the mine power energy sales model. In the coal model, regional production depends mainly on the level of demand for U.S. coal for consumption by electric utilities and U.S. coal production, as well as on binary variables that reflect the impacts of special occurrences, such as strikes. In the development of the regional coal production forecast, projections of U.S. coal production were obtained from U.S. DOE/EIA's "2002 Annual Energy Outlook." The estimation period for the model was 1975-2001.

C.3.b. Residential Energy Sales

Residential energy sales for KPCO are forecasted using two models, the first of which projects the number of residential customers, and the second of which projects kWh usage per customer. The residential energy sales forecast is calculated as the product of the corresponding customer and usage forecasts.

C.3.b.1. Residential Customer Forecasts

The residential customer forecasting model is linear. The level of residential customers is related to total employment in the Company's service area and binary variables. The customer model also employs a lagged dependent variable to represent the gradual adjustment of the number of residential customers to changes in total employment.

C.3.b.2. Residential Energy Usage Per Customer

The kWh usage models are linear, with the independent variables in logarithmic form. Usage is related to service-area total employment, heating and cooling degree-days, the real price of electricity and the real price of natural gas. Both of the energy price terms are five-year moving averages to reflect the delayed effect of prices over time.

Exhibit 2-3 provides a summary of the historical and forecast values of variables used in the development of the Company's residential energy sales forecasts.

C.3.c. Commercial Energy Sales

A single model is used to forecast commercial energy sales. This model is specified as linear, with certain independent variables in logarithmic form. In general, regional economic activity, and relative energy prices are considered to be the primary determinants of long-term commercial load growth. Regional economic activity is represented by regional employment and residential customers serving as another measure of regional economic well-being. Energy prices, represented by the Company's average price of electricity to its commercial customers, and by the statewide real price of natural gas to commercial customers, are included in the model. The model also employs binary variables to account for special occurrences.

Exhibit 2-3 provides a summary of the historical and forecast values of variables used in the development of the Company's commercial energy sales forecasts.

C.3.d. Industrial Energy Sales

C.3.d.1. Manufacturing

The manufacturing forecasting model relates energy sales to real price of natural gas, real price of electricity, FRB production indexes for chemicals and petroleum, service-area manufacturing employment and binary variables. The prices are modeled using five-year moving averages. The dependent and independent variables are modeled as linear, with the production index in logarithmic form.

Exhibit 2-4 provides a summary of the historical and forecast values of variables used in the development of the Company's manufacturing energy sales forecasts.

C.3.d.2. Mine Power

The forecast of KPCO's mine power energy consumption for non-associated mining companies is produced with a model relating mine power energy sales to regional coal production, real price index of petroleum, and average electric price to mine power customers. This model is specified as linear, with the dependent and independent variables in logarithmic form.

Exhibit 2-4 provides a summary of the historical and forecast values of variables used in the development of the mine power energy sales forecast.

C.3.e. All Other Energy Sales

The forecast of public street and highway lighting relates energy sales to service area commercial employment and a binary variable. The model is specified linear with the dependent and independent variables in linear form.

The municipal energy sales model is specified linear with the dependent and independent variables in linear form. Municipal energy sales are modeled relating energy sales to commercial employment, heating and cooling degree days and binary variables. Binary variables are necessary to account for discrete changes in energy sales that result from events such as the addition of new customers or the renegotiation of contracts that increase or decrease energy sales to existing customers. With regard to contractual changes, as a result of notification of contract terminations with Vanceburg and Olive Hill, energy sales are assumed to drop to zero beginning January 1, 2006.

C.3.f. Losses and Unaccounted-For Energy

The forecast losses for KPCO are based on an analysis of the historical relationship between energy sales and generation.

D. FORECAST METHODOLOGY FOR SEASONAL PEAK INTERNAL DEMAND

To forecast peak demand, the Company used algorithms similar to those in the HELM, originally developed by the Electric Power Research Institute. The Company used the methodology to forecast hourly load. Additional inputs in the analysis include weather data, load shapes, transmission and distribution losses, and calendar information. The output from the model includes hourly loads by operating company for the entire forecast period.

The Company used a model that calculates the hourly distribution of loads based on energy sales forecasts, load shapes, and WRFs for system load totals of the operating company. Loads are calculated on an hourly basis and calibrated for weather normalization purposes. The calculated hourly loads for each operating company are added together to form total Regulated AEP East hourly load.

Specifically, the model calculates an hourly load shape for the operating company. The model calculates daily energy based on a WRF. WRFs are defined for all combinations of specified seasons, day types, and daily weather variables. The weather variable used by the model is average daily temperature. The average daily temperature is determined by averaging the daily high and daily low temperatures. The forecast of daily "typical" average temperatures was developed by selecting twelve representative historical months from the past 30-year period (1971 to 2000). These representative months were then combined to form the "typical" or "normal" year.

Different WRFs are defined according to the average temperature values recorded on any given day. WRFs are then applied to weather parameters to yield daily kWh for the operating company. Daily energies are then compared against total annual energy to determine the distribution of energy over the calendar year, resulting in daily energy percentages. These daily percentages are then applied to the annual kWh forecast to determine the daily distribution of forecast energy.

The final step is to allocate the daily energy to hours based on season and day type specific load shapes developed from historical load patterns. Planned demand-side management impacts (modeled independently), an hourly MW load profile, and system loss factors are then added to determine total MW load.

E. LOAD FORECAST RESULTS

E.1. Load Forecast Before DSM Adjustments (Base Forecast)

Exhibit 2-5 present KPCO's annual internal energy requirements, disaggregated by major category (residential, commercial, industrial and other internal sales, as well as losses) on an actual basis for the years 1997-2001 and on a forecast basis for the years 2002-2016. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the Regulated AEP-East is given on Exhibit 2-6.

Exhibits 2-7 and 2-8 show, for KPCO and the Regulated AEP-East, respectively, actual and forecasted summer, winter and annual peak internal demands, along with annual total energy requirements. Also shown are the associated growth rates and annual load factors.

Exhibit 2-9 shows further disaggregation of KPCO's forecasted annual internal energy requirements, along with the associated summer and winter peak demands. Exhibits 2-10 and 2-11 show, for the first two years of the forecast period, i.e., 2002 and 2003, KPCO's disaggregated energy requirements on a monthly basis, along with monthly peak demands.

E.2. Load Forecast After DSM Adjustments

Exhibit 2-12 lists the DSM adjustments (discussed in Chapter 3) that were used to reduce the base forecasts of internal energy requirements and seasonal peak internal demands for both the AEP System and KPCO. The resulting forecasts, which reflect these adjustments, are presented in Exhibits 2-13 through 2-19, in the same order as Exhibits 2-5 to 2-11.

F. IMPACT OF CONSERVATION AND DEMAND-SIDE MANAGEMENT

Since the mid-1970s, conservation, caused in part by higher energy prices and in part by Company-sponsored conservation and DSM programs, has reduced the rate of growth of energy sales and peak demand on the entire AEP System and its operating companies.

Higher energy prices have stimulated technological improvements in the energy efficiency of new electric appliances and industrial machinery, and in the thermal integrity of residential and commercial structures. The effect of these improvements has been to decrease average electricity consumption per customer. It is also believed that higher energy prices have had the effect of inducing a permanent change in consumer attitudes toward energy conservation, which has tended to reduce average energy consumption at all levels of price and technological development.

The Company has recognized both its responsibility to encourage its customers to make wise use of all energy resources, and its expertise in the field of energy consumption planning, and has for some years pursued the policy of providing its customers with opportunities to use energy wisely. It has done so through both educational programs and active promotional programs aimed at broad customer groups. And, through its DSM programs, the Company has maintained an active interest and participation in various programs for improving the cost-effectiveness of customer electricity use. Descriptions of the Company's efforts in this regard are given in Chapter 3 of this report.

As for the load forecast, the impact of conservation on load is captured by the inclusion of energy price variables in the forecasting equations. The impact of past customer conservation and load management activities, including embedded DSM installations, is part of the historical record of electricity use, and, in that sense, is intrinsically reflected in the load forecast. As already noted in the preceding section E.2, the load impacts of expanded DSM installations are analyzed and projected separately, and appropriate adjustments are made to the base load forecast.

No explicit adjustments were made to the forecast to account for national appliance efficiency standards or the National Energy Policy Act of 1992. Historically, such legislation and standards have established policies and programs for promoting energy conservation. To the extent that these policies and programs have already been implemented, their effects are intrinsically reflected in the load forecast. However, the effects of the new 12 SEER high efficiency standard for central air conditioner currently being proposed by Congress, was not explicitly reflected in the load forecast.

G. ENERGY-PRICE RELATIONSHIPS

An understanding of the relationship between energy prices and energy consumption is crucial to developing a forecast of electricity consumption. In theory, the effect of a change in the price of a good on the consumption of that good can be decomposed into two effects, the "income" effect and the "substitution" effect. The income effect refers to the change in consumption of a good attributable to the change in real income incident to the change in the price of that good. For most goods, a decline in real income would induce a decline in consumption. The substitution effect refers to the change in the consumption of a good associated with the change in the price of that good relative to the prices of all other goods. The substitution effect is assumed to be negative in all cases; that is, a rise in the price of a good relative to other, substitute goods would induce a decline in consumption of the original good. Thus, if the price of electricity were to rise, the consumption of electricity would fall, all other things being equal. Part of the decline would be attributable to the income effect; consumers effectively have less income after the price of electricity rises, and part would be attributable to the substitution effect; consumers would substitute relatively cheaper fuels for electricity once its price had risen.

The magnitude of the effect of price changes on consumption differs over different time horizons. In the short-term, the effect of a rise in the price of electricity is severely constrained by the ability of consumers to substitute other fuels or to incorporate more electricity-efficient technology. (The fact that the Company's short-term energy consumption models do not include price as an explanatory variable is a reflection of the belief that this constraint is severe).

In the long-term, however, the constraints on substitution are lessened for a number of reasons. First, durable equipment stocks begin to reflect changes in relative energy prices by favoring the equipment using the fuel that was expected to be cheaper; second, heightened consumer interest in saving electricity, backed by willingness to pay for more efficiency, spurs development of conservation technology; third, existing technology, too expensive to implement commercially at previous levels of energy prices, becomes feasible at the new, higher energy prices; and fourth, normal turnover of electricity-using equipment contributes to a higher average level of energy efficiency. For these reasons, energy price changes are expected to have an effect on long-term energy consumption levels. As a reflection of this belief, most of the Company's long-term forecasting models, including the residential, commercial, manufacturing and mine power energy sales models, directly incorporate the price of electricity as an explanatory variable. In these cases, the coefficient of the price variable provides a quantitative measure of the sensitivity of the forecast value to a change in price. Some of the models, including the residential, commercial and manufacturing models, also incorporate the price of natural gas to consumers in the state of Kentucky.

Electricity price projections for KPCO are based on two different assumptions governing two different forecast horizons. Through 2005, prices are assumed to be held constant in nominal dollars, i.e., they are expected to decline by the rate of inflation. Beyond 2005, nominal prices are assumed to rise at the expected rate of inflation, thus keeping real prices constant. Given these assumptions, projected electricity prices are expected to fall at an average annual rate of 0.6% for KPCO customers during the period 2002-2016. Natural gas prices to consumers in the state of Kentucky, based on the forecasting model described earlier, are expected to decline by 0.4 % per year during the same period.

H. FORECAST UNCERTAINTY AND RANGE OF FORECASTS

Even though load forecasts are created individually for each of the operating companies in the AEP System, and aggregated to form the System total, forecast uncertainty is of primary interest at the System level, rather than the operating company level. Thus, regardless of how forecast uncertainty is characterized, the analysis begins with AEP System load.

Among the ways to characterize forecast uncertainty are: (1) the establishment of confidence intervals that are defined so as to contain a given percentage of possible outcomes, and (2) the development of high- and low-case scenarios that demonstrate the response of forecasted load to changes in driving force variables. AEP continues to support both approaches to analyzing forecast uncertainty; however, for the purposes of this report, scenarios were used for the sensitivity analyses conducted for capacity planning purposes.

The first step in producing high- and low-case scenarios was the estimation of an aggregated "mini-model" of AEP System internal energy requirements. This approach was deemed more feasible than attempting to calculate high and low cases for each of the many equations used to produce the Company's load forecast. The mini-model is intended to be representative of the full forecasting structure employed in producing the base-case forecast for the AEP System, and, by association, for KPCO. The dependent variable is total AEP System internal energy requirements, excluding sales to the System's aluminum reduction plant. This aluminum load is a large and volatile component of total load, which, as mentioned earlier in this report, is treated judgmentally, not analytically, in the load forecast. It is simply added back, as appropriate, to the alternative forecasts produced by the mini-model to create low- and high-case scenarios for total internal energy requirements. The independent variables are real GDP, AEP service-area employment, the average real price of electricity to all AEP customer classes, the average real price of natural gas in the seven states served by AEP-East, and AEP service-area heating and cooling degree-days. All variables are expressed in logarithms. Acceptance of this particular specification is based on the usual statistical tests of goodness-of-fit, on the reasonableness of the elasticities derived from the estimation, and on a rough agreement between the model's load prediction and that produced by the disaggregated modeling approach followed in producing the load forecast.

Once a base-case energy forecast had been produced with the mini-model, low and high values for the independent variables were determined. The values finally decided upon reflect professional judgment. The low- and high-case growth rates in real GDP for the forecast period were 2.5% and 3.3% per year, respectively, compared to 2.9% for the base case. The low- and high-case growth rates for AEP-region total employment were 0.7% and 1.5% per year, respectively, compared to 1.1% per year for the base case. For the real price of natural gas, the low case assumed a growth rate of 0.4% per year, and the high case assumed a growth rate of 1.2% per year. These compare to a base-case growth rate of 0.8% for the average real gas price in the seven states served by AEP. Electricity price was not varied, the assumption being that variation in the price of natural gas in the high and low cases would serve to represent a change in the relative price of the two fuels. Variations in weather were not considered in this analysis; so the value of heating and cooling degree-days remained the same in all cases.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total energy requirements (before DSM adjustments) for the Regulated AEP-East and KPCO are tabulated in Exhibits 2-20 and 2-21, respectively. Graphical displays of the range of forecasts of internal energy requirements and summer peak demand for KPCO are shown in Exhibit 2-22.

For the Regulated AEP-East, the low-case and high-case energy forecasts for the last forecast year, 2016, represent deviations of about 5.4% below and above, respectively, the base-case forecast (with the corresponding KPCO forecast showing about the same percentage deviation). In this regard, the low-case and high-case growth rates in winter peak internal demand for the forecast period were 1.2% and 1.8% per year, respectively, compared to 1.5% per year in the base case.

The corresponding range of load forecasts reflecting DSM adjustments are shown in Exhibits 2-23 (for the AEP System) and 2-24 (for KPCO).

I. SIGNIFICANT CHANGES FROM PREVIOUS FORECAST

I.1. Energy Forecast

Exhibit 2-25 provides a tabular comparison of the 1999 and 2002 forecasts of total internal energy requirements (before DSM adjustments) for both KPCO and the Regulated AEP-East. Exhibit 2-26 shows the comparison for KPCO in graphical form. As these exhibits indicate, KPCO's 2002 energy forecast is initially higher than the 1999 forecast, but in the long term becomes slightly lower, in terms of magnitude (48 GWh, or 0.5%, lower for year 2016) and long-term average annual growth rate (1.6% vs. 1.7%).

For the Regulated AEP-East, the 2002 forecast for year 2016 is 43.3% less than the 1999 forecast, which primarily reflects the effects of the Regulated AEP-East going from a five member pool to a three member pool in 2003.

An examination of the sectoral changes in the KPCO forecast may provide a better understanding of the changes in the aggregate forecast. The forecasted levels of the sectoral components for the year 2016 did not change uniformly with the 0.5% decrease in the forecast of total energy requirements. Specifically, the residential, commercial, and other retail energy sales forecasts were decreased by 2.7%, 10.2 and 89.5%, respectively, while the industrial sales and losses forecasts were increased by 3.7% and 40.5%, respectively.

Factors contributing to the decrease in the residential and commercial energy sales forecasts include the use of an alternative regional economic forecast (i.e., the forecast by Economy.com) and a re-evaluation of expected long-term trends in residential and commercial consumption patterns in light of what has been experienced historically. The changed assumptions reflect the effect of updated information obtained or developed since the 1999 forecast, along with changing perceptions of the future. The other retail sales forecast change reflects the effects of the contract termination for the two municipals served by the Company.

For the industrial sector, the increase reflects a more optimistic outlook for the industries served by KPCO. The increase in losses better reflects the more recent pattern of losses experienced by the Company.

I.2. Peak Internal Demand Forecast

Exhibit 2-27 provides a tabular comparison of the 1999 and 2002 forecasts of the winter peak internal demand (before DSM adjustments) for both KPCO and the Regulated AEP-East. This exhibit indicates that for the winter of 2016/17, KPCO's 2002 peak demand forecast is 4.0% lower than the 1999 forecast. This decrease reflects the change in the forecast for total energy requirements and an evaluation of the weather normal peak experience.

In the case of the Regulated AEP-East, for the winter of 2016/17, the 2002 forecast is 39.6% lower than the 1999 forecast. This change primarily reflects the change from a five member pool to a three member pool.

I.3. Forecasting Methodology

Opportunities to enhance forecasting methods are explored by KPCO on a continuing basis. In this regard, the Company changed how it models peak demand and short-term industrial energy sales. Peak demand is now estimated using hourly load shapes, weather response functions and average daily temperature. Short-term industrial energy sales are now modeled in aggregate.

The Company now uses Economy.com as a source for its regional economic forecasts, rather than Woods & Poole Economics.

J. ADDITIONAL LOAD INFORMATION

Additional information provided for the purposes of this report includes the following:

Exhibit 2-28: KPCO, Average Annual Number of Customers by Class, 1997-2001.

Exhibit 2-29: KPCO, Annual Internal Load by Class (GWh), 1997-2001.

Exhibit 2-30: KPCO and AEP System, Recorded and Weather-Normalized Peak Internal Load (MW) and Energy Requirements (GWh), 1997-2001.

Exhibit 2-31: AEP System and KPCO, Profiles of Monthly Peak Internal Demands, 1996, 2001 (Actual), 2011 and 2016.

The historical profiles presented in Exhibit 2-31 have not been adjusted to reflect normal weather patterns and, therefore, may vary to some degree from the forecast patterns projected for 2011 and 2016. These patterns also reflect the expectation that KPCO will continue to experience its annual peak demand in the winter season, while Regulated AEP-East's annual peak is also expected to occur in the winter.

K. DATA-BASE SOURCES

Sources from within the Company that were used in developing the Company's load forecasts are as follows: (1)Sales for Resale Reports (Form ST-18), (2)daily, monthly and annual System Operation Department reports, (3)monthly financial reports, (4)monthly kWh and revenue SIC reports, and (5)residential tariff schedules and fuel clause summaries for all operating companies.

The data sources from outside the company are varied and include state and federal agencies, as well as Economy.com. Exhibit 2-32 identifies the data series and associated sources, along with notes on adjustments made to the data before incorporation into the load forecasting models.

L. OTHER TOPICS

L.1. Residential Energy Sales Forecast Performance

Exhibit 2-33 provides a comparison of actual vs. the 1999 forecast of KPCO's residential energy sales for the years 1999-2001. In 1999, 2000 and 2001, KPCO's residential energy sales were lower than forecast, by 6.8%, 1.7% and 4.0%, respectively. A major factor contributing to the deviations from forecast was the weather. In 1999, heating degree-days were 7.1% below normal, thus causing less-than-expected energy sales in that year. Likewise, 2001 saw heating degree-days 4.0% below normal, which resulted in residential energy sales being less than expected. However, some over-forecasting occurred in the forecast and thus, the 2002 forecast is somewhat lower than the 1999 forecast.

L.2. Peak Demand Forecast Performance

Exhibit 2-34 provides a comparison of actual vs. the 1999 forecast of KPCO's seasonal internal peak demands for 1999-2001. The exhibit also compares the calculated weather-normalized demands with the forecast values, thus indicating the extent to which weather affected actual demands.

In each winter, KPCO's normalized peaks were less than forecast. Therefore, KPCO's winter peak demand forecast was revised downward.

KPCO's actual and weather-normalized summer peak demands were also mostly below forecast for each year in the period 1999-2002. As a result, KPCO's summer peak demand forecast was revised downward, slightly.

L.3. Other Scenario Analyses

The Company has developed and has begun implementing a plan to be in compliance with the more stringent NOx emission requirements of the Federal EPA's State Implementation Plan (SIP) call. However, it is expected that compliance with these standards will result in higher electricity prices, the magnitude of which has yet to be determined by the Commission. The consumers are expected to respond to these price increases by diminishing their consumption consistent with their relative price elasticities. The net result would be a somewhat lower forecast than presented in this report, all other things being equal. However, the forecast provided herein can be viewed as somewhat conservative in its avoidance of overstating the impacts of these standards.

This forecast incorporates the effects on the membership pool for the Regulated AEP-East. In the previous filing, the Regulated AEP-East was represented by a five-member pool. As a result of deregulation in Ohio and corporate separation, the Regulated AEP-East System is now represented as a three-member pool.

L.4. KPSC Staff Issues Addressed

On June 21, 2000 the Commission issued their Staff's report on KPCO's 1999 Integrated Resource Plan and requested that the Company address certain issues in its next IRP report (this report). The following issues pertaining to load forecasting are restated from the Staff report and addressed below:

1. **Provide a full explanation for any changes in forecasting methodology.**

   See Chapter 2, Section I.3. where this issue has been addressed.

2. **Provide a comparison of forecasted winter and summer peak demands with actual results for the period following Kentucky Power's 1999 IRP, along with a discussion of the reasons for the differences between forecasted and actual peak demands.**

   See Chapter 2, Section I. 2.where this issue has been addressed.

3. **Provide a comparison of the annual forecast of residential energy sales, using the current econometric models, with actual results for the period following the 1999 IRP. Include a discussion of the reasons for the differences between forecasted and actual results.**

   See Chapter 2, Section L.1.where this issue has been addressed.

4. **Kentucky Power should, to the extent possible, report on and reflect in its forecasts, the impacts of increasing wholesale and retail competition in the electric industry.**

   See Chapter 2, Section L.3.where this issued has been addressed.

5. **Kentucky Power should attempt, either in its forecasts or in its uncertainty analysis, to incorporate the impacts of potential environmental costs such as those associated with potential NOx reductions imposed on sources in the Eastern United States.**

   See Chapter 2, Section L.3.where this issued has been addressed.

Exhibit 2-1
(Page 1 of 2)

Kentucky Power Company
Internal Energy Requirements Forecasting Method

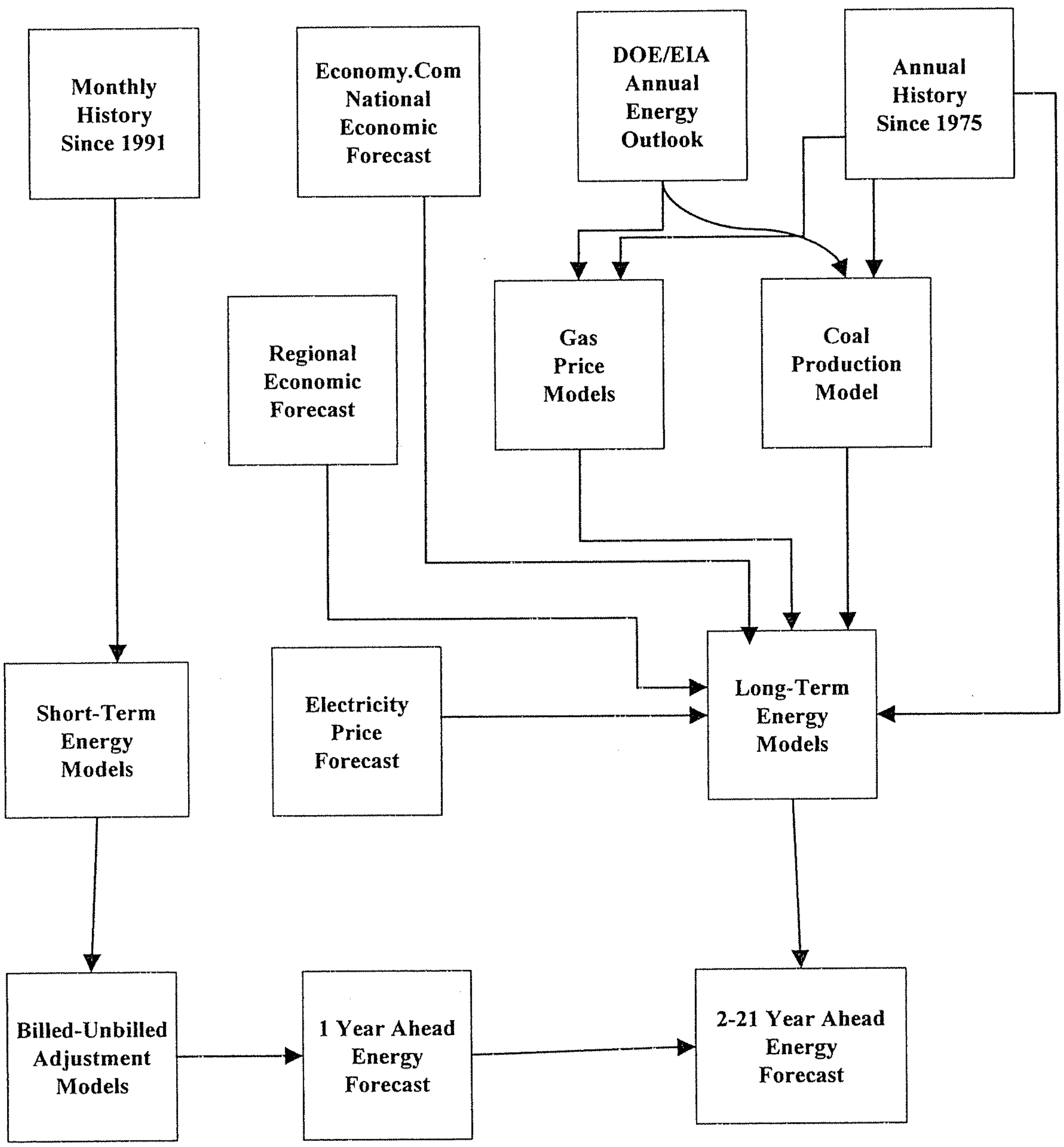


Exhibit 2-1
(Page 2 of 2)

KENTUCKY POWER COMPANY
VARIABLES EMPLOYED IN FORECAST MODELS OF ENERGY SALES

Variable	Residential Customers		Residential Energy Sales		Commercial Customers	Commercial Energy Sales		Total Industrial Energy Sales	Manufacturing Energy Sales	Mine Power Energy Sales	All Other Energy Sales	
	Short Term	Long Term	Short Term	Long Term	Short Term	Short Term	Long Term	Short Term	Long Term	Long Term	Short Term	Long Term
Binary	X	X	X	X	X	X	X	X		X	X	X
Time Trend	X		X		X	X		X			X	X
Electricity Price				X			X		X	X		
Natural Gas Price				X			X		X			
Petroleum Price Index										X		
Residential Customers				X			X					
Service Area Employment		X		X								
Heating Degree-Days			X	X		X					X	X
Cooling Degree-Days			X	X		X					X	X
Commercial Employment							X					
FRB Industrial Production Index									X			X
Manufacturing Employment									X			
Coal Production										X		

Exhibit 2-2

Kentucky Power Company
Peak Internal Demand

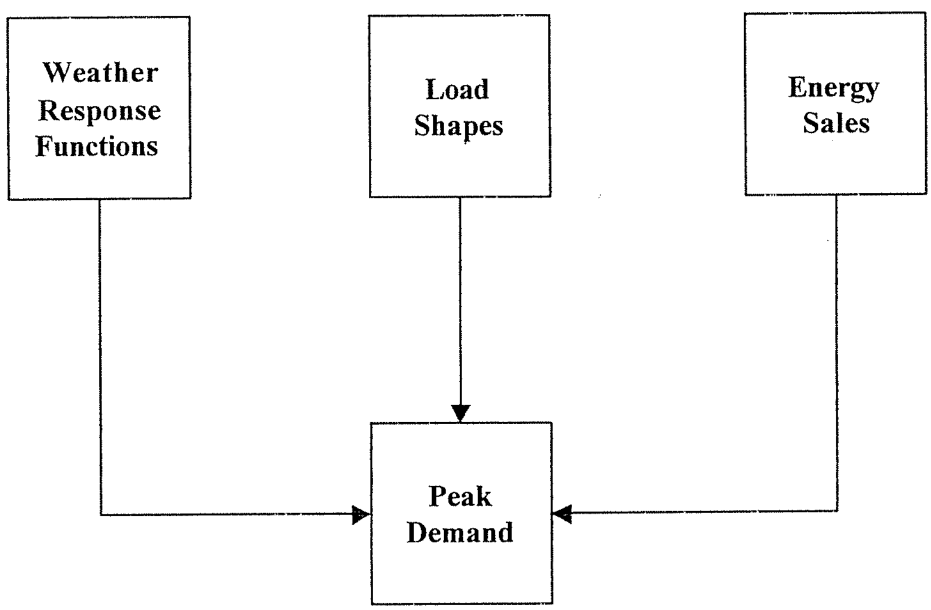


Exhibit 2-3

Kentucky Power Company
Values of Variables Employed in the Long-Term Forecasts of
Residential and Commercial Energy Sales
1975, 2001 and 2016

	Actual		Forecast	Average Annual Growth Rate - %	
	1975	2001	Base 2016	1975-2001	2001-2016
Residential Energy Sales					
1. Service Area Employment	95,261	130,784	163,369	1.2	1.5
Residential Customers	106,399	144,079	161,159	1.2	0.7
1. Cooling Degree Days - Huntington, West Virginia	1,274	1,120	1,166	-0.5	0.3
2. Heating Degree Days - Huntington, West Virginia	4,249	4,264	4,520	0.0	0.4
3. Service Area Employment	95,261	130,784	163,369	1.2	1.5
4. Real Residential Electricity Price Index (1997=1.00)	1.72	1.00	0.91	-2.1	-0.6
5. Real Kentucky Residential Gas Price Index (1997=1.00)	0.42	1.00	0.80	3.4	-1.5
Residential Energy Sales (GWH)	972	2,312	3,286	3.4	2.4
Commercial Energy Sales					
1. Residential Customers	106,399	144,079	161,159	1.2	0.7
2. Service Area Commerical Employment	45,441	86,227	119,653	2.5	2.2
3. Real Commercial Electricity Price Index (1997=1.00)	1.73	1.00	0.91	-2.1	-0.6
4. Real Kentucky Commercial Gas Price Index (1997=1.00)	2.60	1.00	1.29	-3.6	1.7
Commercial Energy Sales (GWH)	1,041	2,031	2,587	2.6	1.6

Exhibit 2-4

Kentucky Power Company

Values of Variables Employed in the Long-Term Forecasts for

Manufacturing and Mine Power Energy Sales

1975, 2001 and 2016

	Actual		Forecast	Average Annual Growth Rate-%	
	1975	2001	Base 2016	1975-2001	2001 2016
Manufacturing Energy Sales					
1. FRB Industrial Production Index for Petroleum (1992=100)	88.0	114.3	176.2	1.0	2.9
2. FRB Industrial Production Index for Chemicals (1992=100)	93.6	121.2	165.9	1.0	2.1
3. Service Area Manufacturing Employment	13,046	8,519	7,124	-1.6	-1.2
4. Real Manufacturing Electricity Price Index (2001=1.00)	1.39	1.00	0.90	-1.3	-0.7
5. Real Kentucky Manufacturing Gas Price Index (2001=1.00)	0.27	1.00	0.80	5.2	-1.5
Manufacturing Energy Sales (GWH)	1,041	1,990	2,737	2.5	2.1
Mine Power Energy Sales					
1. Service Area Coal Production (Million Tons)	61.2	93.5	105.7	1.6	0.8
2. Real Petroleum Price Index (2001=1.00)	0.82	1.00	1.06	0.8	0.4
2. Real Manufacturing Electricity Price Index (2001=1.00)	2.04	1.00	0.91	-2.7	-0.6
Mine Power Energy Sales (GWH)	405	1,071	1,263	3.8	1.1

Exhibit 2-5

Kentucky Power Company
Annual Internal Energy Requirements and Growth Rates
1997-2016

Before DSM Adjustments

	Residential Sales GWH	Residential Sales % Growth	Commercial Sales GWH	Commercial Sales % Growth	Industrial Sales GWH	Industrial Sales % Growth	Other Internal Sales GWH	Other Internal Sales % Growth	Losses GWH	Losses % Growth	Total Internal Energy Requirements GWH	Total Internal Energy Requirements % Growth
Actual												
1997	2,197	--	1,166	--	3,142	--	89	--	304	--	6,897	--
1998	2,156	-1.8	1,195	2.5	3,131	-0.4	91	2.2	419	38.1	6,992	1.4
1999	2,158	0.1	1,231	3.0	3,091	-1.3	91	0.4	535	27.5	7,106	1.6
2000	2,324	7.7	1,244	1.0	3,159	2.2	92	0.9	611	14.4	7,431	4.6
2001	2,312	-0.5	1,279	2.8	3,126	-1.0	91	-1.8	584	-4.5	7,392	-0.5
Forecast												
2002	2,406	4.1	1,340	4.8	3,229	3.3	99	9.1	601	3.0	7,676	3.8
2003	2,435	1.2	1,355	1.1	3,241	0.4	97	-1.6	574	-4.6	7,702	0.3
2004	2,525	3.7	1,396	3.0	3,378	4.2	99	2.1	596	3.8	7,993	3.8
2005	2,580	2.2	1,425	2.1	3,437	1.8	101	1.4	607	2.0	8,150	2.0
2006	2,612	1.2	1,448	1.6	3,448	0.3	12	-87.9	605	-0.3	8,125	-0.3
2007	2,670	2.2	1,478	2.1	3,542	2.7	12	1.6	620	2.4	8,322	2.4
2008	2,723	2.0	1,505	1.9	3,607	1.8	13	1.5	632	1.9	8,480	1.9
2009	2,770	1.7	1,532	1.7	3,662	1.5	13	1.4	642	1.6	8,620	1.6
2010	2,816	1.6	1,558	1.7	3,712	1.4	13	1.4	652	1.5	8,750	1.5
2011	2,864	1.7	1,584	1.7	3,762	1.3	13	1.4	662	1.5	8,884	1.5
2012	2,917	1.9	1,613	1.8	3,820	1.6	13	1.6	673	1.7	9,037	1.7
2013	2,972	1.9	1,641	1.8	3,878	1.5	14	1.5	685	1.7	9,189	1.7
2014	3,025	1.8	1,670	1.7	3,931	1.4	14	1.5	696	1.6	9,336	1.6
2015	3,080	1.8	1,698	1.7	3,989	1.5	14	1.4	707	1.6	9,489	1.6
2016	3,135	1.8	1,726	1.6	4,046	1.4	14	1.4	718	1.6	9,640	1.6
Average Annual Growth Rates:												
1997-2001		1.3		2.3		-0.1		0.4		17.8		1.7
2002-2016		1.9		1.8		1.6		-13.0		1.3		1.6

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-6

Regulated AEP-East
Annual Internal Energy Requirements and Growth Rates
1997-2016

Before DSM Adjustments

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
1997	30,283	--	22,720	--	46,583	--	8,173	--	8,356	--	116,116	--
1998	30,414	0.4	23,599	3.9	47,298	1.5	6,711	-17.9	9,039	8.2	117,061	0.8
1999	31,607	3.9	24,455	3.6	47,352	0.1	5,086	-24.2	8,736	-3.3	117,235	0.1
2000	32,185	1.8	25,216	3.1	42,378	-10.5	4,883	-4.0	9,406	7.7	114,067	-2.7
2001	32,765	1.8	25,656	1.7	40,588	-4.2	4,844	-0.8	8,635	-8.2	112,488	-1.4
Forecast												
2002	33,640	2.7	26,242	2.3	39,437	-2.8	4,919	1.6	8,358	-3.2	112,596	0.1
2003	20,318	-39.6	13,526	-48.5	23,080	-41.5	3,789	-23.0	5,449	-34.8	66,163	-41.2
2004	20,824	2.5	13,993	3.5	23,793	3.1	3,817	0.8	5,616	3.1	68,044	2.8
2005	21,201	1.8	14,300	2.2	24,158	1.5	3,801	-0.4	5,709	1.7	69,169	1.7
2006	21,542	1.6	14,573	1.9	24,607	1.9	3,801	0.0	5,808	1.7	70,331	1.7
2007	21,901	1.7	14,872	2.1	25,116	2.1	3,887	2.3	5,922	2.0	71,698	1.9
2008	22,241	1.6	15,168	2.0	25,527	1.6	3,976	2.3	6,025	1.7	72,936	1.7
2009	22,549	1.4	15,445	1.8	25,931	1.6	4,061	2.1	6,122	1.6	74,108	1.6
2010	22,836	1.3	15,711	1.7	26,325	1.5	4,146	2.1	6,216	1.5	75,234	1.5
2011	23,126	1.3	15,978	1.7	26,733	1.5	4,231	2.0	6,311	1.5	76,378	1.5
2012	23,450	1.4	16,279	1.9	27,174	1.7	4,329	2.3	6,416	1.7	77,648	1.7
2013	23,781	1.4	16,581	1.9	27,596	1.6	4,423	2.2	6,519	1.6	78,899	1.6
2014	24,112	1.4	16,880	1.8	28,036	1.6	4,514	2.1	6,624	1.6	80,166	1.6
2015	24,451	1.4	17,182	1.8	28,482	1.6	4,605	2.0	6,730	1.6	81,450	1.6
2016	24,789	1.4	17,483	1.8	28,932	1.6	4,695	2.0	6,836	1.6	82,735	1.6
Average Annual Growth Rates:												
1997-2001		2.0		3.1		-3.4		-12.3		0.8		-0.8
2002-2016		-2.2		-2.9		-2.2		-0.3		-1.4		-2.2
2003-2016		1.5		2.0		1.8		1.7		1.8		1.7

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-7

Kentucky Power Company
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
1997-2016

Before DSM Adjustments

	Summer Peak			Winter Peak (1)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1997	07/28/97	1,164	--	03/13/98	1,299	--	1,417	--	6,897	--	55.6
1998	08/25/98	1,213	4.2	01/05/99	1,432	10.2	1,299	-8.3	6,992	1.4	61.4
1999	07/30/99	1,215	0.2	01/27/00	1,558	8.8	1,432	10.2	7,106	1.6	56.7
2000	08/09/00	1,210	-0.4	01/03/01	1,579	1.3	1,558	8.8	7,431	4.6	54.3
2001	08/07/01	1,302	7.6	01/04/02	1,551	-1.8	1,579	1.3	7,392	-0.5	53.4
Forecast											
2002		1,271	-2.4		1,503	-3.1	1,551	-1.8	7,676	3.8	56.5
2003		1,286	1.2		1,554	3.4	1,503	-3.1	7,702	0.3	58.5
2004		1,331	3.4		1,592	2.4	1,554	3.4	7,993	3.8	58.7
2005		1,363	2.4		1,586	-0.4	1,592	2.4	8,150	2.0	58.4
2006		1,357	-0.5		1,624	2.4	1,586	-0.4	8,125	-0.3	58.5
2007		1,389	2.4		1,651	1.7	1,624	2.4	8,322	2.4	58.5
2008		1,412	1.7		1,684	2.0	1,651	1.7	8,480	1.9	58.6
2009		1,440	2.0		1,709	1.5	1,684	2.0	8,620	1.6	58.4
2010		1,462	1.5		1,737	1.6	1,709	1.5	8,750	1.5	58.4
2011		1,486	1.6		1,758	1.2	1,737	1.6	8,884	1.5	58.4
2012		1,504	1.2		1,794	2.0	1,758	1.2	9,037	1.7	58.7
2013		1,535	2.0		1,823	1.6	1,794	2.0	9,189	1.7	58.5
2014		1,560	1.6		1,853	1.7	1,823	1.6	9,336	1.6	58.5
2015		1,585	1.7		1,878	1.3	1,853	1.7	9,489	1.6	58.4
2016		1,606	1.3		1,911	1.8	1,878	1.3	9,640	1.6	58.6
Average Annual Growth Rates:											
1997-2001			2.8			4.5		2.7		1.7	
2002-2016			1.7			1.7		1.4		1.6	

Note: (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.
Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-8

Regulated AEP-East
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
1997-2016

Before DSM Adjustments

	Summer Peak			Winter Peak (1)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1997	07/14/97	19,119	--	03/13/98	17,841	--	19,381	--	116,116	--	68.4
1998	07/21/98	19,414	1.5	01/05/99	18,546	4.0	19,414	0.2	117,061	0.8	68.8
1999	07/30/99	19,952	2.8	01/28/00	19,167	3.3	19,952	2.8	117,235	0.1	67.1
2000	08/31/01	18,218	-8.7	01/03/01	18,604	-2.9	19,167	-3.9	114,067	-2.7	67.8
2001	08/08/01	20,218	11.0	02/05/02	17,911	-3.7	20,218	5.5	112,488	-1.4	63.5
Forecast											
2002		19,577	-3.2		16,985	-5.2	19,577	-3.2	112,596	0.1	65.7
2003		10,950	-44.1		11,721	-31.0	11,438	-41.6	66,163	-41.2	66.0
2004		11,225	2.5		11,956	2.0	11,721	2.5	68,044	2.8	66.3
2005		11,455	2.0		12,133	1.5	11,956	2.0	69,169	1.7	66.0
2006		11,631	1.5		12,367	1.9	12,133	1.5	70,331	1.7	66.2
2007		11,856	1.9		12,548	1.5	12,367	1.9	71,698	1.9	66.2
2008		12,031	1.5		12,788	1.9	12,548	1.5	72,936	1.7	66.4
2009		12,263	1.9		12,982	1.5	12,788	1.9	74,108	1.6	66.2
2010		12,450	1.5		13,186	1.6	12,982	1.5	75,234	1.5	66.2
2011		12,647	1.6		13,345	1.2	13,186	1.6	76,378	1.5	66.1
2012		12,802	1.2		13,602	1.9	13,345	1.2	77,648	1.7	66.4
2013		13,049	1.9		13,824	1.6	13,602	1.9	78,899	1.6	66.2
2014		13,261	1.6		14,047	1.6	13,824	1.6	80,166	1.6	66.2
2015		13,476	1.6		14,230	1.3	14,047	1.6	81,450	1.6	66.2
2016		13,651	1.3		14,483	1.8	14,230	1.3	82,735	1.6	66.4
Average Annual Growth Rates:											
1997-2001			1.4			0.1		1.1		-0.8	
2002-2016			-2.5			-1.1		-2.3		-2.2	
2003-2016			1.7			1.6		1.7		1.7	

Note: (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.
Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-9
(Page 1 of 2)

Kentucky Power Company
Annual Internal Load
2002-2011

Before DSM Adjustments

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Internal Energy (GWH)										
Residential	2,406	2,435	2,525	2,580	2,612	2,670	2,723	2,770	2,816	2,864
Commercial	1,340	1,355	1,396	1,425	1,448	1,478	1,505	1,532	1,558	1,584
Industrial	3,229	3,241	3,378	3,437	3,448	3,542	3,607	3,662	3,712	3,762
Total Other Ultimate	11	12	12	12	12	12	13	13	13	13
Total Ultimate Sales	6,987	7,043	7,310	7,454	7,520	7,702	7,848	7,977	8,098	8,222
Municipals	87	86	87	89	0	0	0	0	0	0
Total Sales-for-Resale	87	86	87	89	0	0	0	0	0	0
Total Internal Sales	7,075	7,128	7,398	7,543	7,520	7,702	7,848	7,977	8,098	8,222
Total Losses	601	574	596	607	605	620	632	642	652	662
Total Internal Energy	7,676	7,702	7,993	8,150	8,125	8,322	8,480	8,620	8,750	8,884
Internal Peak Demand (MW)										
Summer	1,271	1,286	1,331	1,363	1,357	1,389	1,412	1,440	1,462	1,486
Preceding Winter	1,551	1,503	1,554	1,592	1,586	1,624	1,651	1,684	1,709	1,737

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-9
(Page 2 of 2)

Kentucky Power Company
Annual Internal Load
2012-2016

Before DSM Adjustments

	2012	2013	2014	2015	2016
Internal Energy (GWH)					
Residential	2,917	2,972	3,025	3,080	3,135
Commercial	1,613	1,641	1,670	1,698	1,726
Industrial	3,820	3,878	3,931	3,989	4,046
Total Other Ultimate	13	14	14	14	14
Total Ultimate Sales	8,364	8,504	8,640	8,782	8,921
Municipals	0	0	0	0	0
Total Sales-for-Resale	0	0	0	0	0
Total Internal Sales	8,364	8,504	8,640	8,782	8,921
Total Losses	673	685	696	707	718
Total Internal Energy	9,037	9,189	9,336	9,489	9,640
Internal Peak Demand (MW)					
Summer	1,504	1,535	1,560	1,585	1,606
Preceding Winter	1,758	1,794	1,823	1,853	1,878

Exhibit 2-10

Kentucky Power Company
Monthly Internal Load
2002

Before DSM Adjustments

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	327.0	237.0	219.2	151.6	133.5	182.4	194.2	191.7	143.5	169.9	188.6	267.8	2,406
Commercial	118.0	113.8	104.4	96.2	114.2	116.1	118.0	118.6	111.8	105.2	103.4	120.4	1,340
Industrial	258.3	269.4	271.3	264.6	274.8	251.5	276.0	268.0	232.2	284.1	288.1	290.9	3,229
Total Other Ultimate	1.0	1.0	1.0	0.8	0.9	0.7	0.8	0.9	0.8	1.1	1.2	1.2	11
Total Ultimate Sales	704.3	621.3	595.8	513.3	523.4	550.7	589.0	579.1	488.4	560.3	581.3	680.4	6,987
Municipals	11.8	7.5	6.7	7.8	6.1	7.5	7.2	7.5	5.9	5.7	7.2	6.6	87
Total Sales-for-Resale	11.8	7.5	6.7	7.8	6.1	7.5	7.2	7.5	5.9	5.7	7.2	6.6	87
Total Internal Sales	716.1	628.8	602.5	521.1	529.5	558.2	596.2	586.6	494.3	566.0	588.5	687.1	7,075
Total Losses	49.3	48.3	57.7	49.9	48.8	55.7	49.4	48.6	41.0	46.9	48.8	57.0	601
Total Internal Energy	765.4	677.1	660.2	571.0	578.3	613.8	645.6	635.3	535.3	612.9	637.2	744.0	7,676
Internal Peak Demand (MW)	1,551	1,412	1,419	1,106	1,093	1,269	1,248	1,271	1,177	1,025	1,159	1,288	1,551

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-11

Kentucky Power Company
Monthly Internal Load
2003

Before DSM Adjustments

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	318.8	246.8	229.7	155.5	144.9	165.6	197.9	191.6	144.7	174.8	191.6	273.6	2,435
Commercial	132.7	105.6	106.5	89.0	100.8	115.0	124.9	120.1	102.7	115.0	111.4	131.5	1,355
Industrial	276.7	255.8	266.0	255.7	268.4	275.1	276.0	268.9	248.6	282.2	281.6	285.6	3,241
Total Other Ultimate	1.2	0.9	1.0	0.8	0.8	0.8	0.8	0.9	0.8	1.1	1.2	1.2	12
Total Ultimate Sales	729.3	609.2	603.3	501.0	515.0	556.4	599.6	581.4	496.8	573.1	585.8	692.0	7,043
Municipals	10.6	8.3	7.1	7.2	5.5	6.6	7.4	7.5	5.9	5.9	7.2	6.4	86
Total Sales-for-Resale	10.6	8.3	7.1	7.2	5.5	6.6	7.4	7.5	5.9	5.9	7.2	6.4	86
Total Internal Sales	739.9	617.5	610.4	508.2	520.5	563.1	607.0	589.0	502.7	579.0	593.0	698.3	7,128
Total Losses	59.5	49.7	49.1	40.9	41.9	45.3	48.8	47.4	40.4	46.6	47.7	56.2	574
Total Internal Energy	799.4	667.2	659.5	549.1	562.4	608.4	655.8	636.3	543.2	625.5	640.7	754.5	7,702
Internal Peak Demand (MW)	1,503	1,353	1,231	1,099	1,119	1,263	1,263	1,286	1,191	1,142	1,173	1,303	1,503

Exhibit 2-12

Regulated AEP-East
Estimated Demand-Side Management Impacts
on Forecasted Energy Requirements and Peak Demands

	Energy Requirements Impacts GWH					Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
2002	-1	-1	0	0	-2	-1	-1
2003	-3	-2	0	0	-5	-1	-2
2004	-4	-2	0	-1	-7	-1	-3
2005	-7	-2	0	-1	-10	-2	-4
2006	-8	-2	0	-1	-11	-2	-4
2007	-8	-2	0	-1	-11	-2	-4
2008	-8	-2	0	-1	-11	-2	-4
2009	-8	-2	0	-1	-11	-2	-4
2010	-8	-2	0	-1	-11	-2	-4
2011	-8	-2	0	-1	-11	-2	-4
2012	-8	-2	0	-1	-11	-2	-4
2013	-8	-2	0	-1	-11	-2	-4
2014	-8	-2	0	-1	-11	-2	-4
2015	-8	-2	0	-1	-11	-2	-4
2016	-8	-2	0	-1	-11	-2	-4

Kentucky Power Company
Estimated Demand-Side Management Impacts
on Forecasted Energy Requirements and Peak Demands

	Energy Requirements Impacts GWH					Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Losses	Total	Summer	Winter Following
2002	-1	-1	0	0	-2	-1	-1
2003	-3	-2	0	0	-5	-1	-2
2004	-4	-2	0	-1	-7	-1	-3
2005	-7	-2	0	-1	-10	-2	-4
2006	-8	-2	0	-1	-11	-2	-4
2007	-8	-2	0	-1	-11	-2	-4
2008	-8	-2	0	-1	-11	-2	-4
2009	-8	-2	0	-1	-11	-2	-4
2010	-8	-2	0	-1	-11	-2	-4
2011	-8	-2	0	-1	-11	-2	-4
2012	-8	-2	0	-1	-11	-2	-4
2013	-8	-2	0	-1	-11	-2	-4
2014	-8	-2	0	-1	-11	-2	-4
2015	-8	-2	0	-1	-11	-2	-4
2016	-8	-2	0	-1	-11	-2	-4

Exhibit 2-13

Kentucky Power Company
Annual Internal Energy Requirements and Growth Rates
1997-2016

Reflecting DSM Adjustments

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
1997	2,197	--	1,166	--	3,142	--	89	--	304	--	6,897	--
1998	2,156	-1.8	1,195	2.5	3,131	-0.4	91	2.2	419	38.1	6,992	1.4
1999	2,158	0.1	1,231	3.0	3,091	-1.3	91	0.4	535	27.5	7,106	1.6
2000	2,324	7.7	1,244	1.0	3,159	2.2	92	0.9	611	14.4	7,431	4.6
2001	2,312	-0.5	1,279	2.8	3,126	-1.0	91	-1.8	584	-4.5	7,392	-0.5
Forecast												
2002	2,405	4.0	1,339	4.7	3,229	3.3	99	9.1	601	3.0	7,674	3.8
2003	2,432	1.1	1,353	1.0	3,241	0.4	97	-1.6	574	-4.6	7,697	0.3
2004	2,521	3.6	1,394	3.0	3,378	4.2	99	2.1	595	3.7	7,986	3.8
2005	2,573	2.1	1,423	2.1	3,437	1.8	101	1.4	606	2.0	8,140	1.9
2006	2,604	1.2	1,446	1.6	3,448	0.3	12	-87.9	604	-0.3	8,114	-0.3
2007	2,662	2.2	1,476	2.1	3,542	2.7	12	1.6	619	2.4	8,311	2.4
2008	2,715	2.0	1,503	1.9	3,607	1.8	13	1.5	631	1.9	8,469	1.9
2009	2,762	1.8	1,530	1.7	3,662	1.5	13	1.4	641	1.6	8,609	1.6
2010	2,808	1.6	1,556	1.7	3,712	1.4	13	1.4	651	1.5	8,739	1.5
2011	2,856	1.7	1,582	1.7	3,762	1.3	13	1.4	661	1.5	8,873	1.5
2012	2,909	1.9	1,611	1.8	3,820	1.6	13	1.6	672	1.7	9,026	1.7
2013	2,964	1.9	1,639	1.8	3,878	1.5	14	1.5	684	1.7	9,178	1.7
2014	3,017	1.8	1,668	1.7	3,931	1.4	14	1.5	695	1.6	9,325	1.6
2015	3,072	1.8	1,696	1.7	3,989	1.5	14	1.4	706	1.6	9,478	1.6
2016	3,127	1.8	1,724	1.6	4,046	1.4	14	1.4	717	1.6	9,629	1.6
Average Annual Growth Rates:												
1997-2001		1.3		2.3		-0.1		0.4		17.8		1.7
2002-2016		1.9		1.8		1.6		-13.0		1.3		1.6

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-14

Regulated AEP-East
Annual Internal Energy Requirements and Growth Rates
1997-2016

Reflecting DSM Adjustments

	Residential Sales		Commercial Sales		Industrial Sales		Other Internal Sales		Losses		Total Internal Energy Requirements	
	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth	GWH	% Growth
Actual												
1997	30,283	--	22,720	--	46,583	--	8,173	--	8,356	--	116,116	--
1998	30,414	0.4	23,599	3.9	47,298	1.5	6,711	-17.9	9,039	8.2	117,061	0.8
1999	31,607	3.9	24,455	3.6	47,352	0.1	5,086	-24.2	8,736	-3.3	117,235	0.1
2000	32,185	1.8	25,216	3.1	42,378	-10.5	4,883	-4.0	9,406	7.7	114,067	-2.7
2001	32,765	1.8	25,656	1.7	40,588	-4.2	4,844	-0.8	8,635	-8.2	112,488	-1.4
Forecast												
2002	33,639	2.7	26,241	2.3	39,437	-2.8	4,919	1.6	8,358	-3.2	112,594	0.1
2003	20,315	-39.6	13,524	-48.5	23,080	-41.5	3,789	-23.0	5,449	-34.8	66,158	-41.2
2004	20,820	2.5	13,991	3.5	23,793	3.1	3,817	0.8	5,615	3.0	68,037	2.8
2005	21,194	1.8	14,298	2.2	24,158	1.5	3,801	-0.4	5,708	1.7	69,159	1.7
2006	21,534	1.6	14,571	1.9	24,607	1.9	3,801	0.0	5,807	1.7	70,320	1.7
2007	21,893	1.7	14,870	2.1	25,116	2.1	3,887	2.3	5,921	2.0	71,687	1.9
2008	22,233	1.6	15,166	2.0	25,527	1.6	3,976	2.3	6,024	1.7	72,925	1.7
2009	22,541	1.4	15,443	1.8	25,931	1.6	4,061	2.1	6,121	1.6	74,097	1.6
2010	22,828	1.3	15,709	1.7	26,325	1.5	4,146	2.1	6,215	1.5	75,223	1.5
2011	23,118	1.3	15,976	1.7	26,733	1.5	4,231	2.0	6,310	1.5	76,367	1.5
2012	23,442	1.4	16,277	1.9	27,174	1.7	4,329	2.3	6,415	1.7	77,637	1.7
2013	23,773	1.4	16,579	1.9	27,596	1.6	4,423	2.2	6,518	1.6	78,888	1.6
2014	24,104	1.4	16,878	1.8	28,036	1.6	4,514	2.1	6,623	1.6	80,155	1.6
2015	24,443	1.4	17,180	1.8	28,482	1.6	4,605	2.0	6,729	1.6	81,439	1.6
2016	24,781	1.4	17,481	1.8	28,932	1.6	4,695	2.0	6,835	1.6	82,724	1.6
Average Annual Growth Rates:												
1997-2001		2.0		3.1		-3.4		-12.3		0.8		-0.8
2002-2016		-2.2		-2.9		-2.2		-0.3		-1.4		-2.2
2003-2016		1.5		2.0		1.8		1.7		1.8		1.7

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-15

Kentucky Power Company
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
1997-2016

Reflecting DSM Adjustments

	Summer Peak			Winter Peak (1)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1997	07/28/97	1,164	--	03/13/98	1,299	--	1,417	--	6,897	--	55.6
1998	08/25/98	1,213	4.2	01/05/99	1,432	10.2	1,299	-8.3	6,992	1.4	61.4
1999	07/30/99	1,215	0.2	01/27/00	1,558	8.8	1,432	10.2	7,106	1.6	56.7
2000	08/09/00	1,210	-0.4	01/03/01	1,579	1.3	1,558	8.8	7,431	4.6	54.3
2001	08/07/01	1,302	7.6	01/04/02	1,551	-1.8	1,579	1.3	7,392	-0.5	53.4
Forecast											
2002		1,270	-2.4		1,502	-3.2	1,551	-1.8	7,674	3.8	56.5
2003		1,285	1.2		1,552	3.4	1,502	-3.2	7,697	0.3	58.5
2004		1,330	3.4		1,589	2.4	1,552	3.4	7,986	3.8	58.7
2005		1,361	2.4		1,582	-0.4	1,589	2.4	8,140	1.9	58.5
2006		1,355	-0.5		1,620	2.4	1,582	-0.4	8,114	-0.3	58.5
2007		1,387	2.4		1,647	1.7	1,620	2.4	8,311	2.4	58.6
2008		1,410	1.7		1,680	2.0	1,647	1.7	8,469	1.9	58.7
2009		1,438	2.0		1,705	1.5	1,680	2.0	8,609	1.6	58.5
2010		1,460	1.5		1,733	1.6	1,705	1.5	8,739	1.5	58.5
2011		1,484	1.6		1,754	1.2	1,733	1.6	8,873	1.5	58.4
2012		1,502	1.2		1,790	2.0	1,754	1.2	9,026	1.7	58.7
2013		1,533	2.0		1,819	1.6	1,790	2.0	9,178	1.7	58.5
2014		1,558	1.6		1,849	1.7	1,819	1.6	9,325	1.6	58.5
2015		1,583	1.7		1,874	1.3	1,849	1.7	9,478	1.6	58.5
2016		1,604	1.3		1,907	1.8	1,874	1.3	9,629	1.6	58.7
Average Annual Growth Rates:											
1997-2001			2.8			4.5		2.7		1.7	
2002-2016			1.7			1.7		1.4		1.6	

Note: (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.
Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-16

Regulated AEP-East
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
1997-2016

Reflecting DSM Adjustments

	Summer Peak			Winter Peak (1)			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1997	07/14/97	19,119	--	03/13/98	17,841	--	19,381	--	116,116	--	68.4
1998	07/21/98	19,414	1.5	01/05/99	18,546	4.0	19,414	0.2	117,061	0.8	68.8
1999	07/30/99	19,952	2.8	01/28/00	19,167	3.3	19,952	2.8	117,235	0.1	67.1
2000	08/31/01	18,218	-8.7	01/03/01	18,604	-2.9	19,167	-3.9	114,067	-2.7	67.8
2001	08/08/01	20,218	11.0	02/05/02	17,911	-3.7	20,218	5.5	112,488	-1.4	63.5
Forecast											
2002		19,576	-3.2		16,984	-5.2	19,576	-3.2	112,594	0.1	65.7
2003		10,949	-44.1		11,719	-31.0	11,437	-41.6	66,158	-41.2	66.0
2004		11,224	2.5		11,953	2.0	11,719	2.5	68,037	2.8	66.3
2005		11,453	2.0		12,129	1.5	11,953	2.0	69,159	1.7	66.1
2006		11,629	1.5		12,363	1.9	12,129	1.5	70,320	1.7	66.2
2007		11,854	1.9		12,544	1.5	12,363	1.9	71,687	1.9	66.2
2008		12,029	1.5		12,784	1.9	12,544	1.5	72,925	1.7	66.4
2009		12,261	1.9		12,978	1.5	12,784	1.9	74,097	1.6	66.2
2010		12,448	1.5		13,182	1.6	12,978	1.5	75,223	1.5	66.2
2011		12,645	1.6		13,341	1.2	13,182	1.6	76,367	1.5	66.1
2012		12,800	1.2		13,598	1.9	13,341	1.2	77,637	1.7	66.4
2013		13,047	1.9		13,820	1.6	13,598	1.9	78,888	1.6	66.2
2014		13,259	1.6		14,043	1.6	13,820	1.6	80,155	1.6	66.2
2015		13,474	1.6		14,226	1.3	14,043	1.6	81,439	1.6	66.2
2016		13,649	1.3		14,479	1.8	14,226	1.3	82,724	1.6	66.4
Average Annual Growth Rates:											
1997-2001			1.4			0.1		1.1		-0.8	
2002-2016			-2.5			-1.1		-2.3		-2.2	
2003-2016			1.7			1.6		1.7		1.7	

Note: (1) Actual winter peak for year may occur in the 4th quarter of that year or in the 1st quarter of the following year.
Note: 2002 data include 6-months actual data and 6-months forecast data.

Kentucky Power Company
Annual Internal Load
2002-2011

Reflecting DSM Adjustments

	2002	2003	2004	2005	2006	2007	2008	2009	2010	2011
Internal Energy (GWH)										
Residential	2,405	2,432	2,521	2,573	2,604	2,662	2,715	2,762	2,808	2,856
Commercial	1,339	1,353	1,394	1,423	1,446	1,476	1,503	1,530	1,556	1,582
Industrial	3,229	3,241	3,378	3,437	3,448	3,542	3,607	3,662	3,712	3,762
Total Other Ultimate	11	12	12	12	12	12	13	13	13	13
Total Ultimate Sales	6,985	7,038	7,304	7,445	7,510	7,692	7,838	7,967	8,088	8,212
Municipals	87	86	87	89	0	0	0	0	0	0
Total Sales-for-Resale	87	86	87	89	0	0	0	0	0	0
Total Internal Sales	7,073	7,123	7,392	7,534	7,510	7,692	7,838	7,967	8,088	8,212
Total Losses	601	574	595	606	604	619	631	641	651	661
Total Internal Energy	7,674	7,697	7,986	8,140	8,114	8,311	8,469	8,609	8,739	8,873
Internal Peak Demand (MW)										
Summer	1,270	1,285	1,330	1,361	1,355	1,387	1,410	1,438	1,460	1,484
Preceding Winter	1,550	1,501	1,551	1,588	1,582	1,620	1,647	1,680	1,705	1,733

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-17
(Page 2 of 2)

Kentucky Power Company
Annual Internal Load
2012-2016

Reflecting DSM Adjustments

	2012	2013	2014	2015	2016
Internal Energy (GWH)					
Residential	2,909	2,964	3,017	3,072	3,127
Commercial	1,611	1,639	1,668	1,696	1,724
Industrial	3,820	3,878	3,931	3,989	4,046
Total Other Ultimate	13	14	14	14	14
Total Ultimate Sales	8,354	8,494	8,630	8,772	8,911
Municipals	0	0	0	0	0
Total Sales-for-Resale	0	0	0	0	0
Total Internal Sales	8,354	8,494	8,630	8,772	8,911
Total Losses	672	684	695	706	717
Total Internal Energy	9,026	9,178	9,325	9,478	9,629
Internal Peak Demand (MW)					
Summer	1,502	1,533	1,558	1,583	1,604
Preceding Winter	1,754	1,790	1,819	1,849	1,874

Exhibit 2-18

Kentucky Power Company
Monthly Internal Load
2002

Reflecting DSM Adjustments

Internal Energy (GWH)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential	326.9	236.9	219.1	151.5	133.5	182.3	194.1	191.6	143.5	169.8	188.5	267.7	2,405
Commercial	117.9	113.7	104.3	96.1	114.2	116.1	118.0	118.6	111.8	105.1	103.3	120.3	1,340
Industrial	258.3	269.4	271.3	264.6	274.8	251.5	276.0	268.0	232.2	284.1	288.1	290.9	3,229
Total Other Ultimate	1.0	1.0	1.0	0.8	0.9	0.7	0.8	0.9	0.8	1.1	1.2	1.2	11
Total Ultimate Sales	704.1	621.1	595.6	513.1	523.4	550.6	588.9	579.0	488.4	560.1	581.1	680.2	6,986
Municipals	11.8	7.5	6.7	7.8	6.1	7.5	7.2	7.5	5.9	5.7	7.2	6.6	87
Total Sales-for-Resale	11.8	7.5	6.7	7.8	6.1	7.5	7.2	7.5	5.9	5.7	7.2	6.6	87
Total Internal Sales	715.9	628.6	602.3	520.9	529.5	558.1	596.1	586.5	494.3	565.8	588.3	686.9	7,073
Total Losses	49.3	48.3	57.7	49.9	48.8	55.7	49.4	48.6	41.0	46.9	48.8	57.0	601
Total Internal Energy	765.2	676.9	660.0	570.8	578.3	613.7	645.5	635.2	535.3	612.7	637.0	743.8	7,674
Internal Peak Demand (MW)	1,551	1,412	1,419	1,106	1,093	1,269	1,248	1,271	1,177	1,025	1,159	1,287	1,551

Note: 2002 data include 6-months actual data and 6-months forecast data.

Exhibit 2-19

Kentucky Power Company
Monthly Internal Load
2003

Reflecting DSM Adjustments

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	318.5	246.5	229.4	155.2	144.7	165.4	197.7	191.4	144.5	174.5	191.3	273.3	2,432
Commercial	132.5	105.4	106.3	88.8	100.7	114.9	124.8	120.0	102.6	114.8	111.2	131.3	1,353
Industrial	276.7	255.8	266.0	255.7	268.4	275.1	276.0	268.9	248.6	282.2	281.6	285.6	3,241
Total Other Ultimate	1.2	0.9	1.0	0.8	0.8	0.8	0.8	0.9	0.8	1.1	1.2	1.2	12
Total Ultimate Sales	728.8	608.7	602.8	500.5	514.7	556.1	599.3	581.1	496.5	572.6	585.3	691.5	7,038
Municipals	10.6	8.3	7.1	7.2	5.5	6.6	7.4	7.5	5.9	5.9	7.2	6.4	86
Total Sales-for-Resale	10.6	8.3	7.1	7.2	5.5	6.6	7.4	7.5	5.9	5.9	7.2	6.4	86
Total Internal Sales	739.4	617.0	609.9	507.7	520.2	562.8	606.7	588.7	502.4	578.5	592.5	697.8	7,123
Total Losses	59.5	49.7	49.1	40.9	41.9	45.3	48.8	47.4	40.4	46.6	47.7	56.2	574
Total Internal Energy	798.9	666.7	659.0	548.6	562.1	608.1	655.5	636.0	542.9	625.0	640.2	754.0	7,697
Internal Peak Demand (MW)	1,502	1,352	1,230	1,099	1,119	1,262	1,262	1,285	1,191	1,142	1,173	1,301	1,502

Exhibit 2-20

Regulated AEP-East
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2002-2016

Before DSM Adjustments

Year	Summer Peak Internal Demands (MW) Low Case	Summer Peak Internal Demands (MW) Base Case	Summer Peak Internal Demands (MW) High Case	Winter (Following) Peak Internal Demands (MW) Low Case	Winter (Following) Peak Internal Demands (MW) Base Case	Winter (Following) Peak Internal Demands (MW) High Case	Internal Energy Requirements (GWH) Low Case	Internal Energy Requirements (GWH) Base Case	Internal Energy Requirements (GWH) High Case
2002	19,341	19,577	19,746	11,694	11,837	11,939	111,241	112,596	113,567
2003	10,788	10,950	11,047	11,892	12,071	12,178	65,184	66,163	66,749
2004	11,042	11,225	11,408	12,096	12,297	12,497	66,933	68,044	69,151
2005	11,250	11,455	11,705	12,302	12,527	12,800	67,929	69,169	70,679
2006	11,392	11,631	11,944	12,495	12,758	13,100	68,881	70,331	72,219
2007	11,586	11,856	12,253	12,671	12,967	13,401	70,064	71,698	74,099
2008	11,721	12,031	12,471	12,804	13,144	13,625	71,052	72,936	75,604
2009	11,909	12,263	12,743	12,938	13,323	13,844	71,966	74,108	77,005
2010	12,051	12,450	12,965	13,069	13,501	14,059	72,825	75,234	78,345
2011	12,197	12,647	13,202	13,192	13,678	14,279	73,662	76,378	79,734
2012	12,300	12,802	13,396	13,314	13,857	14,500	74,606	77,648	81,254
2013	12,488	13,049	13,679	13,422	14,024	14,702	75,511	78,899	82,713
2014	12,645	13,261	13,927	13,533	14,192	14,904	76,441	80,166	84,190
2015	12,803	13,476	14,176	13,643	14,360	15,106	77,383	81,450	85,681
2016	12,919	13,651	14,387	13,748	14,527	15,311	78,299	82,735	87,198
Average Annual Growth Rate %									
2002-2016	-2.8	-2.5	-2.2	1.2	1.5	1.8	-2.5	-2.2	-1.9
2003-2016	1.4	1.7	2.1	1.1	1.4	1.8	1.4	1.7	2.1

Exhibit 2-21

Kentucky Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2002-2016

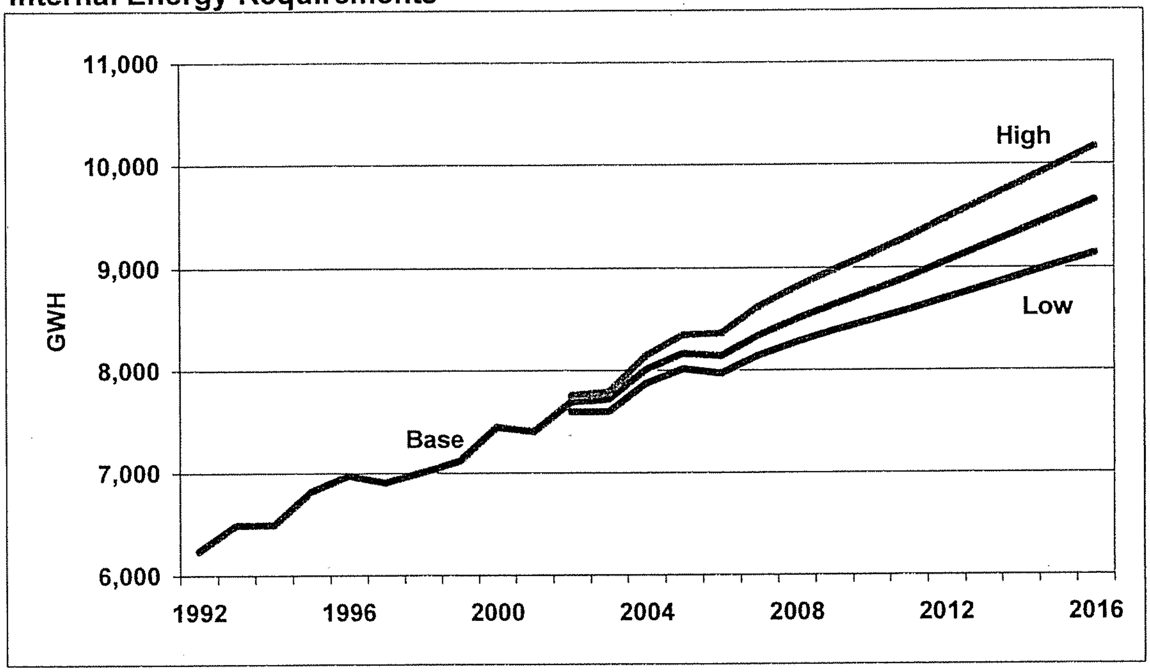
Before DSM Adjustments

	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2002	1,256	1,271	1,282	1,484	1,503	1,515	7,584	7,676	7,742
2003	1,267	1,286	1,298	1,531	1,554	1,568	7,588	7,702	7,770
2004	1,309	1,331	1,352	1,566	1,592	1,618	7,863	7,993	8,123
2005	1,338	1,363	1,393	1,558	1,586	1,621	8,004	8,150	8,328
2006	1,329	1,357	1,393	1,591	1,624	1,668	7,958	8,125	8,343
2007	1,358	1,389	1,436	1,614	1,651	1,707	8,133	8,322	8,601
2008	1,376	1,412	1,464	1,640	1,684	1,745	8,261	8,480	8,790
2009	1,399	1,440	1,496	1,660	1,709	1,776	8,371	8,620	8,957
2010	1,415	1,462	1,523	1,682	1,737	1,809	8,470	8,750	9,112
2011	1,433	1,486	1,551	1,696	1,758	1,836	8,568	8,884	9,275
2012	1,445	1,504	1,574	1,724	1,794	1,877	8,683	9,037	9,457
2013	1,469	1,535	1,609	1,745	1,823	1,911	8,794	9,189	9,633
2014	1,487	1,560	1,638	1,767	1,853	1,946	8,902	9,336	9,805
2015	1,506	1,585	1,668	1,784	1,878	1,975	9,015	9,489	9,981
2016	1,520	1,606	1,693	1,808	1,911	2,014	9,123	9,640	10,160
Average Annual Growth Rate % 2002-2016	1.4	1.7	2.0	1.4	1.7	2.1	1.3	1.6	2.0

Exhibit 2-22

Kentucky Power Company
Range of Forecasts

Internal Energy Requirements



Winter Peak Demand

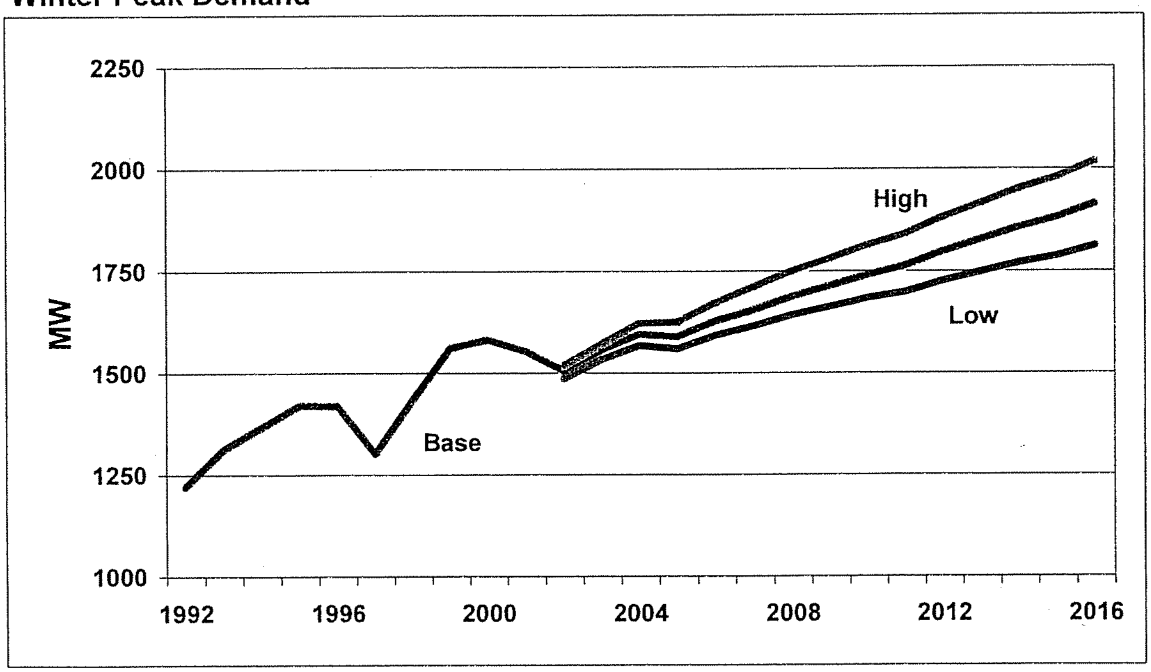


Exhibit 2-23

Regulated AEP-East
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2002-2016

Reflecting DSM Adjustments

	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2002	19,340	19,576	19,745	11,693	11,836	11,938	111,239	112,594	113,565
2003	10,787	10,949	11,046	11,890	12,069	12,176	65,179	66,158	66,744
2004	11,041	11,224	11,407	12,093	12,294	12,494	66,926	68,037	69,144
2005	11,248	11,453	11,703	12,298	12,523	12,796	67,919	69,159	70,669
2006	11,390	11,629	11,942	12,491	12,754	13,096	68,870	70,320	72,208
2007	11,584	11,854	12,251	12,667	12,963	13,397	70,053	71,687	74,088
2008	11,719	12,029	12,469	12,800	13,140	13,621	71,041	72,925	75,593
2009	11,907	12,261	12,741	12,934	13,319	13,840	71,955	74,097	76,994
2010	12,049	12,448	12,963	13,065	13,497	14,055	72,814	75,223	78,334
2011	12,195	12,645	13,200	13,188	13,674	14,275	73,651	76,367	79,723
2012	12,298	12,800	13,394	13,310	13,853	14,496	74,595	77,637	81,243
2013	12,486	13,047	13,677	13,418	14,020	14,698	75,500	78,888	82,702
2014	12,643	13,259	13,925	13,529	14,188	14,900	76,430	80,155	84,179
2015	12,801	13,474	14,174	13,639	14,356	15,102	77,372	81,439	85,670
2016	12,917	13,649	14,385	13,744	14,523	15,307	78,288	82,724	87,187
Average Annual Growth Rate %									
2002-2016	-2.8	-2.5	-2.2	1.2	1.5	1.8	-2.5	-2.2	-1.9
2003-2016	1.4	1.7	2.1	1.1	1.4	1.8	1.4	1.7	2.1

Exhibit 2-24

Kentucky Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2002-2016

Reflecting DSM Adjustments

Year	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
	Low Case	Base Case	High Case	Low Case	Base Case	High Case	Low Case	Base Case	High Case
2002	1,255	1,270	1,281	1,483	1,502	1,514	7,582	7,674	7,740
2003	1,266	1,285	1,297	1,529	1,552	1,566	7,583	7,697	7,765
2004	1,308	1,330	1,351	1,563	1,589	1,615	7,856	7,986	8,116
2005	1,336	1,361	1,391	1,554	1,582	1,617	7,994	8,140	8,318
2006	1,327	1,355	1,391	1,587	1,620	1,664	7,947	8,114	8,332
2007	1,356	1,387	1,434	1,610	1,647	1,703	8,122	8,311	8,590
2008	1,374	1,410	1,462	1,636	1,680	1,741	8,250	8,469	8,779
2009	1,397	1,438	1,494	1,656	1,705	1,772	8,360	8,609	8,946
2010	1,413	1,460	1,521	1,678	1,733	1,805	8,459	8,739	9,101
2011	1,431	1,484	1,549	1,692	1,754	1,832	8,557	8,873	9,264
2012	1,443	1,502	1,572	1,720	1,790	1,873	8,672	9,026	9,446
2013	1,467	1,533	1,607	1,741	1,819	1,907	8,783	9,178	9,622
2014	1,485	1,558	1,636	1,763	1,849	1,942	8,891	9,325	9,794
2015	1,504	1,583	1,666	1,780	1,874	1,971	9,004	9,478	9,970
2016	1,518	1,604	1,691	1,804	1,907	2,010	9,112	9,629	10,149
Average Annual Growth Rate % 2002-2016	1.4	1.7	2.0	1.4	1.7	2.0	1.3	1.6	2.0

Exhibit 2-25

Kentucky Power Company and Regulated AEP-East
Total Internal Energy Requirements
Comparison of 1999 and 2002 Forecasts

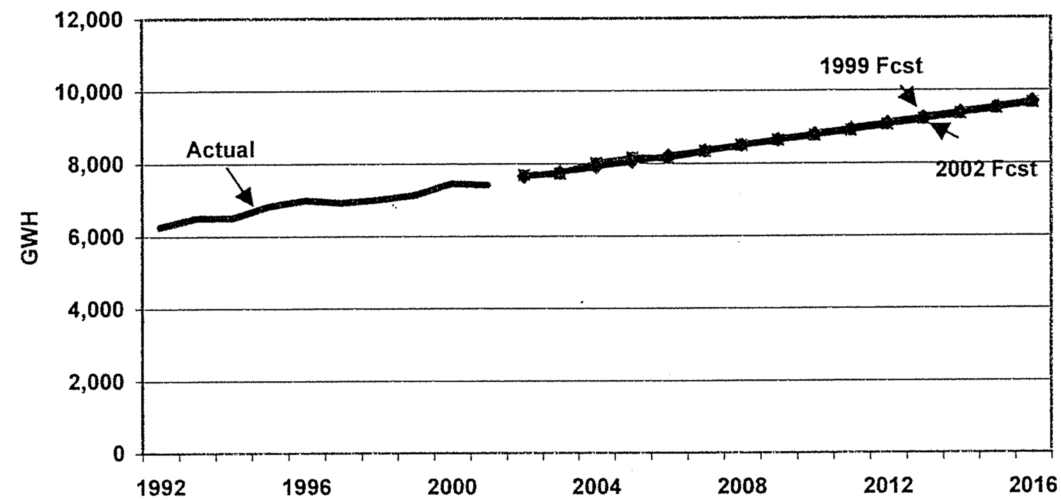
Before DSM Adjustments

	KPCo				Regulated AEP-East			
Forecast Year	2002 Forecast GWH	1999 Forecast GWH	Change From 1996 Forecast GWH	Change From 1996 Forecast Percent	2002 Forecast GWH	1999 Forecast GWH	Change From 1996 Forecast GWH	Change From 1996 Forecast Percent
1999	-	7,297	-	-	-	118,710	-	-
2000	-	7,406	-	-	-	116,116	-	-
2001	-	7,524	-	-	-	118,205	-	-
2002	7,676	7,632	44	0.6	112,596	120,268	-7,672	-6.4
2003	7,702	7,746	-44	-0.6	66,163	122,358	-56,195	-45.9
2004	7,993	7,895	98	1.2	68,044	124,168	-56,124	-45.2
2005	8,150	8,045	105	1.3	69,169	125,978	-56,809	-45.1
2006	8,125	8,194	-69	-0.8	70,331	127,788	-57,457	-45.0
2007	8,322	8,343	-21	-0.2	71,698	129,598	-57,900	-44.7
2008	8,480	8,493	-13	-0.2	72,936	131,408	-58,472	-44.5
2009	8,620	8,642	-22	-0.3	74,108	133,219	-59,111	-44.4
2010	8,750	8,792	-42	-0.5	75,234	135,029	-59,795	-44.3
2011	8,884	8,941	-57	-0.6	76,378	136,839	-60,461	-44.2
2012	9,037	9,090	-53	-0.6	77,648	138,649	-61,001	-44.0
2013	9,189	9,240	-51	-0.6	78,899	140,459	-61,560	-43.8
2014	9,336	9,389	-53	-0.6	80,166	142,269	-62,103	-43.7
2015	9,489	9,538	-49	-0.5	81,450	144,079	-62,629	-43.5
2016	9,640	9,688	-48	-0.5	82,735	145,889	-63,154	-43.3
2002-2016 Growth Rate (%)	1.6	1.7			-2.2	1.4		

Exhibit 2-26

Kentucky Power Company
Comparison of Forecasts

Internal Energy Requirements



Winter Peak Demand

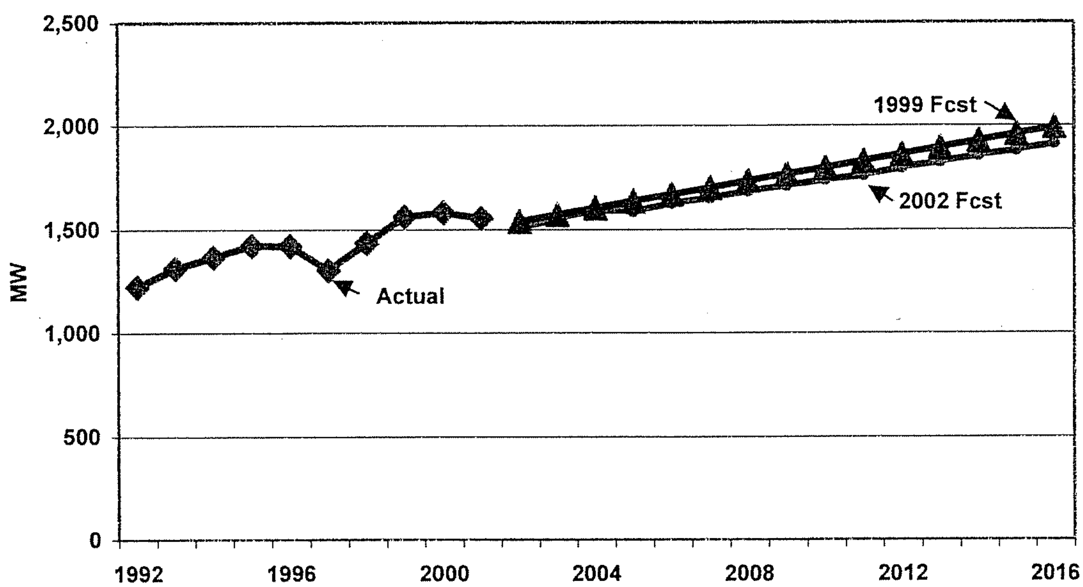


Exhibit 2-27

Kentucky Power Company and Regulated AEP-East
Winter Peak Internal Demands
Comparison of 1999 and 2002 Forecasts

Before DSM Adjustments

	KPCo				Regulated AEP-East			
Forecast Year	2002 Forecast MW	1999 Forecast MW	Change From 1996 Forecast MW	Change From 1996 Forecast Percent	2002 Forecast MW	1999 Forecast MW	Change From 1996 Forecast MW	Change From 1996 Forecast Percent
1999	-	1,462	-	-	-	19,082	-	-
2000	-	1,488	-	-	-	19,372	-	-
2001	-	1,512	-	-	-	19,660	-	-
2002	1,503	1,537	-34	-2.2	16,985	19,955	-2,970	-14.9
2003	1,554	1,570	-16	-1.0	11,721	20,244	-8,523	-42.1
2004	1,592	1,602	-10	-0.6	11,956	20,533	-8,577	-41.8
2005	1,586	1,635	-49	-3.0	12,133	20,821	-8,688	-41.7
2006	1,624	1,667	-43	-2.6	12,367	21,110	-8,743	-41.4
2007	1,651	1,699	-48	-2.8	12,548	21,399	-8,851	-41.4
2008	1,684	1,732	-48	-2.8	12,788	21,687	-8,899	-41.0
2009	1,709	1,764	-55	-3.1	12,982	21,976	-8,994	-40.9
2010	1,737	1,796	-59	-3.3	13,186	22,265	-9,079	-40.8
2011	1,758	1,829	-71	-3.9	13,345	22,553	-9,208	-40.8
2012	1,794	1,861	-67	-3.6	13,602	22,842	-9,240	-40.5
2013	1,823	1,894	-71	-3.7	13,824	23,131	-9,307	-40.2
2014	1,853	1,926	-73	-3.8	14,047	23,419	-9,372	-40.0
2015	1,878	1,958	-80	-4.1	14,230	23,708	-9,478	-40.0
2016	1,911	1,991	-80	-4.0	14,483	23,997	-9,514	-39.6
2002-2016 Growth Rate (%)	1.7	1.9			-1.1	1.3		

Exhibit 2-28

Kentucky Power Company
Average Annual Number of Customers by Class
1997-2001

	1997	1998	1999	2000	2001
A. Residential					
1. Heating Customers	71,038	73,288	75,302	77,003	78,244
2. Nonheating Customers	71,160	69,310	67,872	66,649	65,835
3. Total	142,197	142,598	143,174	143,652	144,079
B. Commercial	23,690	24,213	24,782	25,501	25,966
C. Industrial					
1. Manufacturing	1,077	1,065	1,059	976	974
2. Mine Power	613	600	586	550	543
3. Total	1,690	1,664	1,645	1,526	1,517
D. Other Ultimate Sales					
1. Street Lighting	476	499	529	527	447
2. Other	0	0	0	0	0
3. Total	476	499	529	527	447
E. Total Ultimate Sales	168,054	168,974	170,129	171,206	172,009
F. Internal Sales for Resale					
1. Municipals	2	2	2	2	2
2. Other	0	0	0	0	0
3. Total	2	2	2	2	2
G. Total Internal Sales	168,056	168,976	170,131	171,208	172,011

Exhibit 2-29

Kentucky Power Company
Annual Internal Load by Class (GWH)
1997-2001

	1997	1998	1999	2000	2001
A. Residential					
1. Heating Customers	1,399	1,361	1,394	1,534	1,527
2. Nonheating Customers	797	795	765	790	785
3. Total	2,197	2,156	2,158	2,324	2,312
B. Commercial	1,166	1,195	1,231	1,244	1,279
C. Industrial					
1. Manufacturing	2,031	2,021	2,017	2,088	1,990
2. Mine Power	1,111	1,110	1,074	1,071	1,137
3. Total	3,142	3,131	3,091	3,159	3,126
D. Other Ultimate Sales					
1. Street Lighting	10	11	11	11	11
2. Other	0	0	0	0	0
3. Total	10	11	11	11	11
E. Total Ultimate Sales	6,515	6,492	6,491	6,738	6,729
F. Internal Sales for Resale					
1. Municipals	79	81	81	81	79
2. Other	0	0	0	0	0
3. Total	79	81	81	81	79
G. Total Internal Sales	6,593	6,572	6,572	6,819	6,808
H. Losses	304	419	535	611	584
I. Total Internal Load	6,897	6,992	7,106	7,431	7,392

Exhibit 2-30

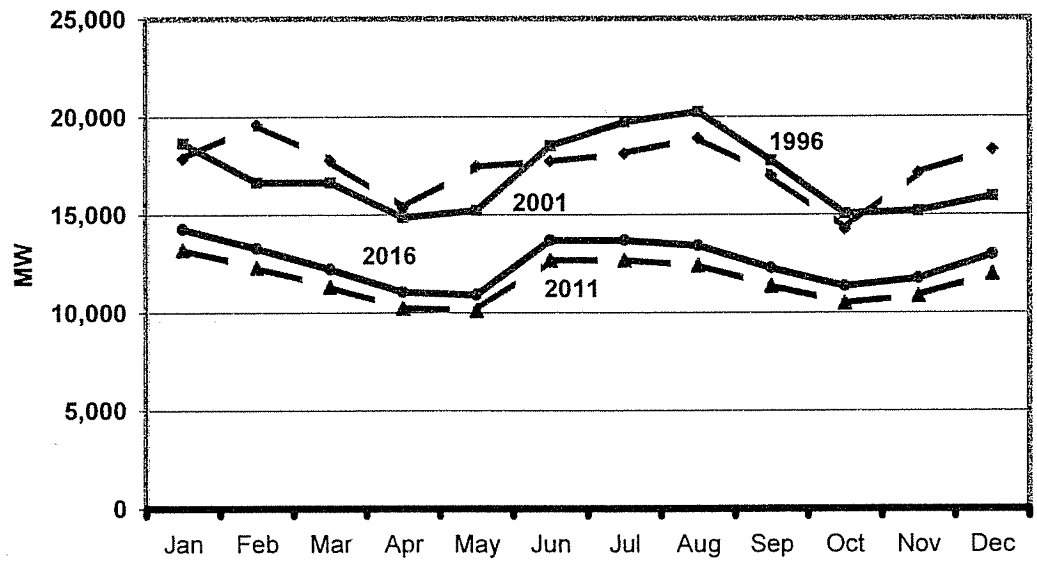
Kentucky Power Company and Regulated AEP-East
Recorded and Weather-Normalized Peak Load (MW) and Energy (GWH)
1997-2001

	1997	1998	1999	2000	2001
Kentucky Power Company					
A. Peak Load - Summer					
1. Recorded	1,164	1,213	1,215	1,210	1,302
2. Weather-Normalized	1,165	1,217	1,183	1,264	1,225
B. Peak Load - Winter					
1. Recorded	1,299	1,432	1,558	1,579	1,551
2. Weather-Normalized	1,399	1,413	1,433	1,473	1,495
C. Energy					
1. Recorded	6,897	6,992	7,106	7,431	7,392
2. Weather-Normalized	6,949	7,083	7,134	7,457	7,429
Regulated AEP-East					
A. Peak Load - Summer					
1. Recorded	19,119	19,414	19,952	18,218	20,218
2. Weather-Normalized	19,822	20,117	19,636	19,516	19,218
B. Peak Load - Winter					
1. Recorded	17,841	18,546	19,167	18,634	17,911
2. Weather-Normalized	18,989	18,786	18,405	18,512	18,468
C. Energy					
1. Recorded	116,116	117,061	117,235	114,067	112,488
2. Weather-Normalized	116,779	117,761	117,224	114,387	113,100

Exhibit 2-31

Regulated AEP-East and Kentucky Power Company
Profiles of Monthly Peak Internal Demands
1996 and 2001 (Actual)
2011 and 2016

Regulated AEP-East



Kentucky Power Company

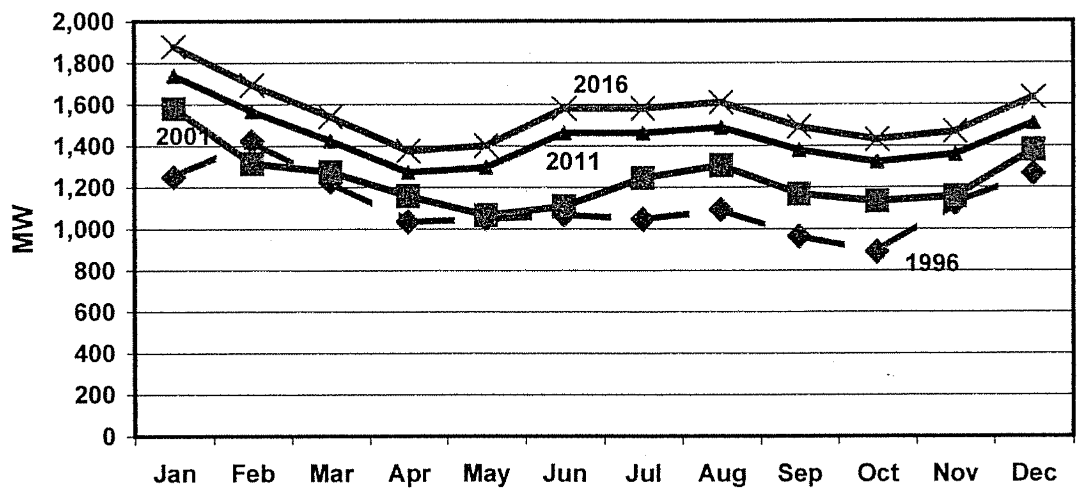


Exhibit 2-32

KENTUCKY POWER COMPANY LOAD FORECAST
DATA SOURCES OUTSIDE THE COMPANY

DATA SERIES	FREQUENCY	GEOGRAPHIC	INTERVAL	SOURCE	ADJUSTMENT
Average Daily Temperatures at time of Daily Peak Load	Daily	Selected weather stations throughout the AEP System	1975-2002	NOAA (1)	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/75-5/02	NOAA (1)	Annual Sums used in long-term models
FRB Production Index, Manufacturing	Monthly and Quarterly	U. S.	1975:1-2002:1 2002:2-2023:4	BOG/FRB (3) Economy.Com (2)	Forecast allocated to months for short-term models; Annual averages used in long-term models
CPI-All Urban Wage Earners	Quarterly	U. S.	1975:1-2023:4	Economy.Com (2)	Annual averages used in long-term models
Index of Producer Prices-Industrial Commodities	Quarterly	U. S.	1975:1-2023:4	Economy.Com (2)	Annual averages used in long-term models
U. S. and Kentucky Natural Gas Prices by Sector	Annually	U. S.	1973-2001	DOE/EIA (4)	None
U. S. Coal Production and Consumption	Annually	U. S.	1975-2023	DOE/EIA (5)	None
Kentucky Coal Production	Annually	Selected Kentucky Counties	1975-2001	DMMCK (6)	None
Employment (Total and Selected Sectors), Personal Income and Population	Annually	Selected Kentucky Counties	1975-2023	Economy.Com (2)	None

Source Citations:
(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) May 2002 Forecast, Economy.Com.
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1975-2002
(4) U. S. Department of Energy/Energy Information Administration "Natural Gas Monthly" and "Natrual Gas Annual," Selected Issues.
(5) U. S. Department of Energy/Energy Information Administration "2002 Annual Energy Outlook" and "Quarterly Coal Report," Selected Issues.
(6) Department of Mines and Minerals, Commonwealth of Kentucky "Annual Report," Selected Issues.
(7) June 2002 Forecast, Economy.Com.

Exhibit 2-33

Kentucky Power Company
Residential Energy Sales
1999-2001
Actual vs. 1999 IRP

	Residential Energy Sales -GWH				Heating Degree Days			
Year	Actual	1999 Forecast	GWH Difference	% Difference	Actual	Normal	HDD Difference	% Difference
1999	2,158	2,315	-157	-6.8	4,197	4,520	-323	-7.1
2000	2,324	2,363	-39	-1.7	4,603	4,520	83	1.8
2001	2,312	2,409	-97	-4.0	4,264	4,520	-256	-5.7

Exhibit 2-34

Kentucky Power Company
Seasonal Peak Demands
1999-2001
Actual vs. 1999 Forecast

Summer Peak Demand - MW				
Summer	Actual	1999 Forecast	MW Difference	% Difference
1999	1,215	1,231	-16	-1.3
2000	1,210	1,250	-40	-3.2
2001	1,302	1,270	32	2.5
Summer	Weather Normalized	1999 Forecast	MW Difference	% Difference
1999	1,183	1,231	-48	-3.9
2000	1,264	1,250	14	1.1
2001	1,225	1,270	-45	-3.5

Winter Peak Demand - MW				
Winter	Actual	1999 Forecast	MW Difference	% Difference
1999/00	1,558	1,462	96	6.6
2000/01	1,579	1,488	91	6.1
2001/02	1,551	1,512	39	2.6
Winter	Weather Normalized	1999 Forecast	MW Difference	% Difference
1999/00	1,433	1,462	-29	-2.0
2000/01	1,473	1,488	-15	-1.0
2001/02	1,495	1,512	-17	-1.1

Kentucky Power Company

Seasonal and Annual Peak Internal Demands, Energy Requirements and Load Factor

1994-2015

	Summer Peak			Preceding Winter Peak			Annual Peak, Energy and Load Factor				
	Date	MW	% Growth	Date	MW	% Growth	MW	% Growth	GWH	% Growth	Load Factor %
Actual											
1994	06/20/94	1,079	---	01/19/94	1,309	---	1,309	---	6,483	---	56.5
1995	08/15/95	1,136	5.3	02/09/95	1,363	4.1	1,363	4.1	6,808	5.0	57.0
1996	08/07/96	1,087	-4.3	02/05/96	1,418	4.0	1,418	4.0	6,960	2.2	55.9
1997	07/28/97	1,164	7.1	01/17/97	1,417	-0.1	1,417	-0.1	6,897	-0.9	55.6
1998	08/25/98	1,213	4.2	03/13/98	1,299	-8.3	1,299	-8.3	6,992	1.4	61.4
1999	07/30/99	1,215	0.2	01/05/99	1,432	10.2	1,432	10.2	7,106	1.6	56.7
2000	08/09/00	1,210	-0.4	01/27/00	1,558	8.8	1,558	8.8	7,368	3.7	53.8
2001	08/07/01	1,302	7.6	01/03/01	1,579	1.3	1,579	1.3	7,433	0.9	53.7
2002	08/05/02	1,326	1.8	01/04/02	1,551	-1.8	1,551	-1.8	7,714	3.8	56.8
2003	08/26/03	1,212	-8.6	01/27/03	1,564	0.8	1,564	0.8	7,531	-2.4	55.0
2004		1,319	8.9	01/31/04	1,478	-5.5	1,512	-3.3	8,074	7.2	60.8
Forecast											
2005		1,364	3.4		1,687	14.2	1,687	11.6	8,241	2.1	55.8
2006		1,355	-0.6		1,695	0.5	1,695	0.5	8,249	0.1	55.5
2007		1,384	2.1		1,722	1.6	1,722	1.6	8,410	2.0	55.8
2008		1,398	1.1		1,741	1.1	1,741	1.1	8,522	1.3	55.9
2009		1,420	1.5		1,769	1.6	1,769	1.6	8,629	1.3	55.7
2010		1,437	1.2		1,791	1.2	1,791	1.2	8,738	1.3	55.7
2011		1,458	1.4		1,816	1.4	1,816	1.4	8,857	1.4	55.7
2012		1,473	1.1		1,834	1.0	1,834	1.0	8,979	1.4	55.9
2013		1,498	1.7		1,866	1.7	1,866	1.7	9,103	1.4	55.7
2014		1,519	1.4		1,892	1.4	1,892	1.4	9,229	1.4	55.7
2015		1,540	1.4		1,918	1.4	1,918	1.4	9,357	1.4	55.7

Note: 2004 data are six months actual and six months forecast.

Corporate Planning and Budgeting
2005 Load Forecast

Kentucky Power Company

REQUEST

Provide all the Power Flow Analyses scenarios, including considerations for wheeling and loop flows, performed for the proposed transmission line.

RESPONSE

The Hazard area transmission system serves the area load via three transmission line facilities, namely, Beaver Creek-Hazard 138 kV line via Topmost and other stations, Pineville-Hazard 161 kV line via Stinnett and other stations and Fleming-Collier 69 kV line via Mayking and other stations. This system configuration makes the area less prone to wheeling and loop flows. There is no generation in the Hazard Area.

Power flow scenarios for the area study analysis included peak load base condition and single contingencies involving the two major sources of power to the area – the 161 kV and the 138 kV line outages.

The above power flow analysis scenarios represent the following four base cases:

- 2004 winter peak without Wooten Interconnection
- 2004 winter peak with Wooten Interconnection
- 2007 winter peak without Wooten Interconnection
- 2007 winter peak with Wooten Interconnection

Single contingency outages of 138 kV and 161 kV lines were performed for base case conditions.

Files marked
Q4 - 2004 W cases.ppt
Q4 - 2007w base without new interconnection.zip
Q4 - 2007w Pineville 161 kV Line Out without new interconnection.zip
Q4 - 2007w Beaver Ck 138 kV Line Out without new interconnection_NON CONVERGENT.zip
Q4 - 2007w base with new interconnection.zip
Q4 - 2007w Pineville 161 kV Line Out with new interconnection.zip
Q4 - 2007w Beaver Ck 138 kV Line Out with new interconnection.zip

Kentucky Power Company

REQUEST

Provide a description and a summary of Kentucky Power's multi-year transmission expansion plan.

RESPONSE

In order to provide operational flexibility and adequate generation outlet capacity, alleviate single contingency thermal overload and low voltage concerns, and to improve the overall reliability in Kentucky Power's Ashland area, a plan is being implemented to re-conductor approximately 1.33 miles of 69 kV line between Bellefonte (KPCo) and Pleasant Street (OPCo) stations, installing a 20% series reactor on the Center Street-Hanging Rock 69 kV circuit at the Hanging Rock station and installing a 14.4 MVAr capacitor bank at the Highland 69 kV station. The first portion, re-conductoring Bellefonte-Pleasant Street 69 kV, would be completed in 2005. The remainder of these improvements is scheduled to be completed in 2006.

The on going planning process, as described in Question 1, is performed on a periodic basis to identify the need and timing for future system improvement.

Kentucky Power Company

REQUEST

Provide a description and a summary of AEP's implemented or planned actions for the power system stability and security considerations resulting from North American Electric Reliability Council's ("NERC") recommendations in reaction to the August 2003 event.

RESPONSE

AEP has reviewed various processes, procedures, communication protocols and transmission system analyses in light of the August 2003 blackout that was initiated by generation conditions and transmission issues in the Northeastern Ohio. The NERC recommendations were primarily directed to study actions and initiatives to be undertaken by various NERC sub-groups and or the Regional Reliability Councils and specific actions to be taken by First Energy and/or the MISO and PJM Security Coordinators. It must be noted that the robust AEP Transmission System blocked southern propagation of this cascading blackout and provided the source of restoration power via AEP's interconnections with First Energy and the transmission system in lower Michigan. In addition, AEP conducted studies in early 2003, the results of which were shared with First Energy that showed that the Cleveland area was vulnerable to a blackout under heavy load conditions coincident with the unavailability of lakefront generation and key transmission facilities. FERC recognized the potential for remedial action, had First Energy heeded these study results, in the FERC Order of December 24, 2003.

AEP is continually examining our procedures, processes, communication protocols with neighboring systems and Security Coordinators, and reliability evaluation techniques to ensure that the reliability of the AEP System is maintained at acceptable levels at all times.

As an outgrowth of the NERC recommendations, but also part of AEP's continual effort to ensure reliability, AEP has taken several actions since the 2003 Blackout. For example, AEP has reviewed the Zone 3 relay protection on numerous circuits. Settings that did not meet NERC new relay setting criteria were either changed, protection systems replaced or are scheduled to be replaced within the next two years. AEP has successfully undergone a NERC Readiness Audit attesting to AEP's ability to operate the transmission system in a reliable manner. AEP has also reviewed and harden the cyber security of AEP's Control Centers and various communications channels. AEP has reviewed the Vegetation Management Program and has enhanced attention to the criticality of EHV Right of Way clearing. AEP has improved interaction and security processes with PJM—AEP's Security Coordinator. AEP has also enhanced real-time transmission assessment tools, providing AEP transmission operators with information and assessment tools to ensure continued reliability. Training programs for AEP transmission system operators has also expanded.

AEP, as a member or ECAR and an active participant on various NERC committees, continues to support the improvement of clarity of NERC and regional reliability Standards. AEP also supports expansion of the NERC and regional Compliance Programs as a necessary and critical initiative to support reliable operation as the electric industry continues to evolve. AEP participated in an ECAR assessment of its reactive power and voltage criteria. AEP also continues to support ECAR transmission reliability assessments.

Kentucky Power Company

REQUEST

Provide the transmission planning staff's recommendations to executive management to justify funding the proposed transmission line, and include any analysis of alternatives considered.

RESPONSE

The requested information is being provided on the attached CD, labeled as follows:

Q7 - AEP-LGE Interconnections Justification.doc
Q7 - AEP-LGE Interconnections ExecutiveSummary.doc

Kentucky Power Company

REQUEST

Provide supporting information showing how the AEP/Louisville Gas and Electric Company interconnection (proposed Hazard line) ranked among AEP's proposed system-wide transmission system capital projects.

RESPONSE

The AEP/Louisville Gas and Electric Company interconnection (proposed Hazard line) ranked fourth among AEP's proposed system-wide transmission system capital projects. The attached file shows the top seventeen 2006 projects.
One file marked

Q8 - Copy of Project Optimization.pdf

Kentucky Power Company

REQUEST

Provide backup for the alternative (Habart to Hazard) transmission project cost estimate.

RESPONSE

A Third Line from the Harbert to the Hazard 138 kV stations & Misc. Station Work was considered as an alternate plan that provides similar transmission system benefits. The cost for that plan was estimated as follows:

- **Harbert - New Bulan 138 kV Circuit**
    - Construct approximately 14-mile long single circuit 138 kV line from Harbert Station to a new station site near Bulan Station (Estimated cost $9,640,000)
- **New Bulan - Hazard 138 kV Circuit**
    - Construct approximately 5-mile long single circuit 138 kV line from the new station site near Bulan Station to Hazard Station (Estimated cost $3,500,000)
- **Harbert 138 kV Station**
    - (Estimated cost $1,060,000)
- **Other Miscellaneous Station Work**
    - Hazard Station (Estimated cost $525,000)
    - Beaver Creek 138 kV and other 69 kV stations - System Protection (Estimated Cost $250,000)

Kentucky Power Company

REQUEST

Provide a one-line diagram for the transmission area surrounding the proposed line.

RESPONSE

One file marked

Q10 - One-Line Diagram Hazard Area.jpg

Kentucky Power Company

REQUEST

Provide AEP's system protection criteria and the relay settings.

RESPONSE

The following bulleted items include some of the major AEP protection philosophies and principles.

- All faults in the targeted zone of protection should be detected and isolated.
- Backup protection must be provided to protect for failure of any single contingency equipment failure mode.
- Efforts should be made to protect as much of the infrastructure as reasonably possible with high-speed protection.
- Relay settings should be set above the emergency ratings of the associated equipment as to not be a limiting factor in the operation of the facilities.
- Primary and backup relay systems should be coordinated to minimize the amount of infrastructure that is isolated or disturbed for an operating event.
- Protection requirements shall be in accordance with regulatory requirements such as those from NERC and ECAR.
- Protection practices should reflect "good utility practices" and industry standards such as IEEE.
- All transmission lines operated at 138 kV and above must have high-speed pilot protection.
- Backup line protection should be set to clear line faults in 60 cycles or less under normal system conditions, not contingency situations.

Relay settings have not yet been identified pending future protection studies to be performed as noted in response to Question # 12.

Kentucky Power Company

REQUEST

Provide all the protection studies performed for the proposed line.

RESPONSE

The protection studies for the proposed station and lines have not yet been initiated. These studies, which will require a joint review of AEP- Kentucky and LG&E are expected to be initiated in the fall of 2005.

Kentucky Power Company

REQUEST

Provide a description of the generation dispatch scenarios for the proposed line.

RESPONSE

As indicated in Q 4, there is no generation in the Hazard Area. Three lines (a 138 kV, a 161 kV and a 69 kV line) provide the power requirement of the area. Therefore, external generation does not affect the performance of the local transmission system.

Kentucky Power Company

REQUEST

Provide the short-circuit analysis performed for the proposed line.

RESPONSE

Three Phase fault (in Amps) with and without the proposed connections are as follows:

System Condition	Hazard 138 kV Station	Hazard 161 kV Station	Leslie 161 kV Station
2004 base condition without the proposed 161 kV connection	5005	4192	4490
2004 base condition with the proposed 161 kV connection	6734	5980	6537

Kentucky Power Company

REQUEST

Provide a copy of the AEP Transmission Planning Department organization chart.

RESPONSE

One file marked

Q15 - TPOrgChart.jpg

Kentucky Power Company

REQUEST

Kentucky Power uses probabilistic techniques in its area transmission system studies to determine the need for reliability upgrades for its transmission network. Does the design phase utilize probabilistic solutions and does the result meet the industry standard N-1, N-2 criteria?

RESPONSE

Kentucky Power uses probabilistic techniques to compare projects to determine priority for each project. The power flow process, however, includes analyzing the performance of the transmission system utilizing peak load condition and outages based on the industry standard N-1 and N-2 criteria.

Kentucky Power Company

REQUEST

In its planning process Kentucky Power utilizes a probabilistic approach to transmission planning that allows for a higher risk factor if less load is affected. Specifically, it accepts a 95 percent reliability criteria for its normal system under steady-state conditions, and, with a single contingency, the reliability criteria falls to 92 percent for 138 kV lines and lower. Kentucky Power states that these percentages are consistent with good utility practice.

a. Does the NERC publish planning probability risk standards for transmission lines?

b. Does the East Central Area Reliability Council publish planning probability risk standards for transmission lines?

c. Is there an industry standard?

RESPONSE

a. NERC does not publish probabilistic risk standards for transmission lines. NERC standards consist of deterministic simulation tests designed to define the minimum level reliability for the planning and operation of bulk transmission facilities.

b. The East Area Reliability Council only provides deterministic simulation tests to be applied to the bulk transmission network to avoid widespread cascading outages. The planning and operation of local load serving transmission facilities are left to the discretion of entities that are responsible for planning of the local area transmission system.

To our knowledge, there is no probabilistic risk standard for the industry.

Kentucky Power Company

REQUEST

Does the $4.2 million estimated cost of the transmission line include the costs of the protection studies to be performed and any costs for solutions that may be needed in response to those studies?

RESPONSE

The cost of protection studies is included in the estimate.