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KENTUCKY POWER COMPANY

INTEGRATED RESOURCE PLANNING REPORT
TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

Submitted Pursuant to
Commission Regulation 807 KAR 5:058

VOLUME A

Case No. 2009-00339
August 17, 2009

KENTUCKY POWER COMPANY

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TO THE
KENTUCKY PUBLIC SERVICE COMMISSION

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Case No. 2009-________
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This report was prepared under the supervision of :

Errol K. Wagner
Kentucky Power Company
Director of Regulatory Services
101 A Enterprise Drive
P.O. Box 5190
Frankfort, Kentucky 40602

TABLE OF CONTENTS

VOLUME A

VOLUME B

VOLUME C

VOLUME D

CONFIDENTIAL SUPPLEMENT (NOT REDACTED)

1. OVERVIEW AND SUMMARY

1. OVERVIEW AND SUMMARY

A. GENERAL REMARKS

Kentucky Power Company (KPCo) is one of the operating companies of the AEP System - East Zone ("AEP - East Zone" or "AEP-East"), which is planned and operated on a wholly integrated basis.[1] In this regard, KPCo's resource plans must be considered in the context of the AEP System-East Zone.

Structural changes have taken place in the electric utility industry since KPCo's last Integrated Resource Plan (IRP) filing. Foremost among these is a transition away from the integrated utility generation, transmission, and distribution structure to a combination of regional transmission organizations that will have responsibility for planning and operation of the transmission system, along with a generating system that includes both utility and independent generating capacity operating in a market structure.

This report presents the results obtained from evaluations carried out in connection with the development of integrated resource plans for the AEP System-East Zone and KPCo. The information contained herein includes assumptions relating to overall study parameters and the integration of supply-side resources and demand-side management (DSM) programs.

The IRP is based on current mandatory environmental requirements (the existing SO_2 reduction programs under the CAAA and the AEP settlement in the New Source Review case as well as the NO_x SIP Call requirements for reductions in the Midwestern U.S.). It also assumes a need to reduce the production of CO_2 similar in many respects to legislation that has been proposed at the federal level in recent months.

Below see Table 1 for AEP-East which provides the resource additions and reductions for the period 2009-2023. Specific for KPCo is the addition of peaking capacity in 2018 and the addition of intermediate capacity in 2023.

[1] 1 The operating companies are: Appalachian Power (APCo); Columbus Southern Power (CSP); Indiana Michigan Power (I&M); Kentucky Power (KPCo); Kingsport Power; Ohio Power (OPCo); and Wheeling Power.

Table 1

2009 AEP System - *East Zone IRP*

MW	*Planned Resource Reductions* (A)		*Planned Resource Additions* (A)						
			DSM		RENEWABLE			THERMAL	
	Unit Retirements (summer-rating)	**CCS Retrofits** (Chilled Ammonia-auxiliary impact @ ~15%)	*Embedded* **Demand Reduction**(B) *(Cumul Contribution)*	*New* **Demand Reduction**(C) *(Cumul Contribution)*	**Solar** (Nameplate)	***Wind*** (Nameplate)	**Biomass** (Dedicated Facility)	**Duty Cycle Type: BL=Baseload INT=Intermediate/Cyclic PKG=Peaking**	***Ownership***
2009			58	0	0	200			
2010	(440)	MT-Ph1 (4)	145	179	3	350			
2011			267	358	3	600			
2012	(560)		*269*	537	*9*	*700*	*60*		
2013			271	716	14	500		(Dresden) 540-MW INT	*APCo*
2014	(395)	MT-Ph2 (31)	272	894	14			(Cook 2)+45MW BL	*I&M*
2015	(415)		273	1,073	14			(Cook 1&2)+168MW BL	*I&M*
2016			273	1,073	14	100		(Cook 1)+68MW BL	*I&M*
2017	(600)		273	1,073	13			(Cook 2)+68MW BL	*I&M*
2018	(580)		273	1,073	17		127(D)	(Cook 1)+ 68MW BL and 628-MW PKG	*PKG: APCo/KPCo 50/50; BL: I&M*
2019	(480)		273	1,073	17				
2020		MT-Ph3 (160)	273	1,073	16	200			
2021	(690)		273	1,073	35	150	127(D)	*611-MW INT*	*APCo*
2022			273	1,073	52	100		628-MW PKG	*APCo*
2023	(660)		273	1,073	0	100		611-MW INT	*APCo/KPCo 50/50*
2023 Cumul. Contribution/Nameplate	***(4,820)***	***(195)***	***273***	***1,073***	***220***	***3,000***	***314***	***3,435***	
(PJM) Capacity Value (E)					***154***	***390***			
Cumul. (Nameplate) Contribution			*3%*	*13%*	*3%*	*36%*	*4%*	*41%*	
Cumul. (Capacity) Contribution			*5%*	*19%*	*3%*	*7%*	*6%*	*61%*	

Peaking	1,256	*37%*
Intermediate (*incl. Dresden*)	1,762	*51%*
Baseload (D.C. Cook Uprates)	417	*12%*
	3,435	

'NET' CAPACITY RESOURCE ADDITIONS:
Additions - Reductions = 624

(A) Not shown are smaller unit derates and uprates embedded in the current plan which are largely offseting (e g FGD retrofit auxiliary load loss, offset by turbine/MSV uprates)
(B) "Embedded" DSM represents 'known & measurable', commission-approved program activity now projected in the most recent load forecast
(C) "New" DSM represents incremental activity projected based on estimated contribution & program cost (vs avoided cost) parameters, from recent Market Potential Studies, and were generally limited to an EPRI Jan '09 study identifying a "Realistically Achievable Potential" Note: Such 'New' (increm) DSM-DR activity modeled thru 2015 only
(D) Reflects a single repowered (100%) dedicated biomass (e g stoker) unit from MR 1-4
(E) Capacity value in PJM for wind is initially set at 13% of nameplate and 70% of nameplate for solar

Conclusion:

The recommended plan provides the lowest practical cost solution through a combination of traditional supply, renewable and demand side investments. The tempered load growth combined with additional renewable resources and other additional supply-side resources, and increased DR/EE initiatives reduce the need for new peaking capacity until 2018, with new baseload capacity now not required until beyond the forecast period. The AEP System-East Zone (including KPCo) is expected to have adequate resources to serve its customers' requirements throughout the forecast period. See Section F.1, for KPCo's stand-alone position for the forecast period.

The planning process is a continuous activity; assumptions and plans are continually reviewed as new information becomes available and modified as appropriate. Indeed, the resource expansion plan reported herein reflects, to a large extent, assumptions that are subject to change; it is simply a snapshot of the future at this time. It is not a commitment to a specific course of action, since the future, now more than ever before, is highly uncertain, particularly in light of the current economic conditions, the movement towards increasing use of renewable generation and end-use efficiency, as well as legislative proposals to control "greenhouse gases" which could result in the retirement or retrofit of existing generating units, impacting the supply of capacity and energy to Kentucky Power. The resource planning process is becoming increasingly complex given pending legislative and regulatory restrictions, technology advancement, changing energy supply fundamentals, uncertainty of demand and energy efficiency advancements all of which advancements all of which necessitate flexibility in any ongoing plan. The ability to invest in capital intensive infrastructure is increasingly challenged in light of current economic conditions and the impact on Kentucky Power customers will be a primary consideration.

B. PLANNING OBJECTIVES (807 KAR 5:058 Sec. 5.1)

The primary objective of power system planning is to assure the reliable, adequate and economical supply of electric power and energy to the consumer, in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy.

Other objectives of a resource plan include planning flexibility, creation of an optimum asset mix, adaptability to risk and affordability. In addition, given unique impact on generation of environmental compliance, the planning effort must be in concert with anticipated long-term requirements as established by the environmental compliance planning process.

C. COMPANY OPERATIONS AND INTERRELATIONSHIP WITH THE AEP SYSTEM (807 KAR 5:058 Sec. 5.1)

Kentucky Power serves a population of about 369,000 (176,000 retail customers) in a 3,762 square-mile area in eastern Kentucky. The principal industries served are primary metals, chemicals and allied products, petroleum refining and coal mining. The Company also sells and transmits power at wholesale to other electric utilities, municipalities, electric cooperatives, and non-utility entities engaged in the wholesale power market.

KPCo's internal load usually peaks in the winter; the all-time peak internal demand of 1,678 megawatts (MW) occurred on January 25, 2008. On August 24, 2007, an all-time summer peak internal demand of 1,358 MW was experienced. Of KPCo's total internal energy requirements in 2008, which amounted to 7,907 gigawatt-hours (GWh), residential, commercial, and industrial energy sales accounted for 31.4%, 18.1%, and 42.0%, respectively. Public street and highway lighting, sales for resale, and all other categories accounted for the remaining 8.5%.

In comparison, the AEP - East Zone collectively serves a population of about 7.2 million (3.3 million retail customers) in a 41,000 square-mile area in parts of Indiana, Kentucky, Michigan, Ohio, Tennessee, Virginia, and West Virginia. In 2008 the residential, commercial, and industrial customers accounted for 28.4%, 22.2%, and 35.9%, respectively, of the System's total internal energy requirements of 131,466 GWh. The remaining 13.5% was supplied for use in the public street and highway lighting, sales for resale, and all other categories.

The AEP-East Zone experienced its all-time peak internal demand of 22,413 MW in the summer season of 2007, on August 8th. The all-time winter peak internal demand, 22,270 MW, was experienced on January 16, 2009. If sales to non-affiliated power systems are included, the AEP-East Zone reached its all-time peak total demand of 26,467 MW on August 21, 2003.

As of June 1, 2009, KPCo owns and operates the 1,060-megawatt, coal-fired Big Sandy Plant, consisting of an 800-MW unit and a 260-MW unit, at Louisa, Kentucky, and has a unit power agreement with AEP Generating Company, an affiliate, to purchase 393 megawatts of capacity through December 7, 2022 or the end of the lease agreement from the Rockport Plant, located in southern Indiana. By comparison, as of June 1, 2009, the AEP System-East Zone's total generating capability was 28,726 MW reflecting the reduction for a 250 MW unit power sale currently in place with CP&L. The CP&L unit power sale expires at the end of 2009 at which time the AEP System-East Zone's total generating capability will become 28,976 MW. Such capacity is predominantly coal-fired generating units along with conventional hydroelectric, pumped storage, and nuclear capacity.

The AEP System's generating eastern operating companies, including KPCo, are electrically interconnected by a high capacity transmission system extending from Virginia to Michigan. This eastern transmission system, consisting of an integrated 765-kV, 500-kV, and 345-kV, extra-high-voltage (EHV) network, together with an extensive underlying 138-kV transmission network, and numerous interconnections with neighboring power systems, is planned, constructed, and operated to provide a reliable mechanism to transmit the electrical output from the AEP System–East Zone generating plants to the principal load centers and to provide open access transmission service pursuant to FERC Order No. 888.

AEP transferred functional control of transmission facilities in the Eastern part of its system to the PJM Interconnection, LLC a regional transmission organization (RTO) in 2004. This transfer was approved by the Kentucky Public Service Commission in Case No. 2002-00475 order dated May 19, 2004. The PJM RTO assumed the monitoring, market operations and planning responsibilities of these facilities. In addition, PJM assumed the Open Access Same Time Information System (OASIS) responsibility including the evaluation and disposition of requests for transmission services over the AEP System–East Zone transmission system. PJM also became the North American Electric Reliability Council (NERC) Reliablity Coordinator for the AEP System-East Zone transmission system. AEP-East continues to maintain and physically operate all of its transmission facilities. AEP-East retains operational responsibility for those facilities that are not under PJM functional control, and is involved in the various operations, and planning stakeholder processes of PJM. In addition, PJM directs the dispatch of the AEP System-East Zone generating resources to meet minute-to-minute loads and determines the planning reserve required to maintain generation resource adequacy.

D. LOAD FORECASTS (807 KAR 5:058 Sec. 5.2.,5.3., and 5.4.)

It should be noted that the load forecasts presented herein were developed in early 2009 and finalized in June 2009 and do not reflect the experience for the summer season of 2009 and later, or other relevant changes.[2]

KPCo's forecasts of energy consumption for the major customer classes were developed by using both short-term and long-term econometric models. These energy forecasts were determined in part by forecasts of the regional economy, which, in turn, are based on the October 2008 national economic forecast of Moody's Economy.com. The forecasts of seasonal peak demands were developed using an analysis of energy, load shapes and load factor that estimates hourly demand.

Some of the key assumptions on which the load forecast is based include:

- a recession with recovery being experienced in 2010 and 2011 and moderate growth beyond;
- electricity prices are tied to an Energy Information Administration (EIA) long-term outlook which reflects slow real growth;
- generally slow growth in the Company's service-area population;
- normal weather.

Table 2 provides a summary of the "base" forecasts of the seasonal peak internal demands and annual energy requirements for KPCo and the AEP-East Zone for the years 2009 to 2023. The forecast data shown on this table reflects adjustments for filed DSM programs. In addition, inherent in the forecast are the impacts of past customer conservation and load management activities, including DSM programs already in place.

As Table 2 indicates, during the period 2009-2023, KPCo's base internal energy requirements are forecasted to increase at an average annual rate of 0.9%, while the corresponding summer and winter peak internal demands are forecasted to grow at average annual rates of 0.9% and 0.7%, respectively. KPCo's annual peak demand is expected to continue to occur in the winter season.

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[2] The load forecasts (as well as the historical loads) presented in this report reflect the traditional concept of internal load, i.e., the load that is directly connected to the utility's transmission and distribution system and that is provided with bundled generation and transmission service by the utility. Such load serves as the starting point for the load forecasts used for generation planning. Internal load is a subset of *connected load*, which also includes directly connected load for which the utility serves only as a transmission provider. Connected load serves as the starting point for the load forecasts used for transmission planning.

TABLE 2 KPCo and AEP-East Zone Forecast of Peak Internal Demand and Energy Requirements After Filed DSM Programs 2009-2023						
	KPCo			Regulated AEP-East System		
	Peak Internal Demand		Internal Energy Req'ts (GWh)	Peak Internal Demand		Internal Energy Req'ts (GWh)
Year	Summer (MW)	Winter Following (MW)		Summer (MW)	Winter Following (MW)	
2009	1,308	1,639	7,963	21,077	20,338	123,530
2010	1,338	1,668	8,144	21,160	21,726	122,116
2011	1,357	1,672	8,286	22,368	21,864	132,096
2012	1,364	1,689	8,354	22,595	22,130	133,603
2013	1,379	1,700	8,417	22,876	22,297	134,724
2014	1,389	1,711	8,472	23,079	22,456	135,657
2015	1,400	1,717	8,530	23,276	22,550	136,608
2016	1,408	1,728	8,593	23,423	22,702	137,621
2017	1,420	1,739	8,651	23,651	22,840	138,487
2018	1,431	1,750	8,707	23,828	22,976	139,317
2019	1,441	1,754	8,762	23,999	23,038	140,107
2020	1,448	1,771	8,816	24,112	23,268	140,917
2021	1,462	1,784	8,874	24,358	23,441	141,837
2022	1,474	1,791	8,940	24,566	23,561	142,889
2023	1,483	1,799	9,007	24,768	23,674	143,998
% Average Growth Rate, 2009-2023	0.9	0.7	0.7	1.2	1.1	1.1
Note: Regulated AEP-East System Peak Internal Demands indicated above include "traditional" interruptible/non-firm loads, which are assumed to aggregate to 591 MW (summer) and 615 MW (winter) throughout the forecast period. KPCo does not have such loads.						

Similarly, the AEP-East Zone's base internal energy requirements during the forecast period are projected to increase at an average annual rate of 1.1% over the 2009-2023 period, while the corresponding summer and winter peak internal demands are projected to grow at average annual rates of 1.2% and 1.1%, respectively. The AEP-East Zone's annual peak demand is expected to occur in the summer season.

Table 3 shows KPCo and AEP-East Zone load forecast information as in Table 2 except that the peak demands and energy requirements have been increased, where appropriate, to exclude the impact of the filed DSM programs assumed to be implemented during the forecast period. A comparison of the data shown on Tables 2 and 3 indicates that the expanded DSM program effects are minor and do not affect the long-term load growth rates.

TABLE 3 KPCo and AEP-East Zone Forecast of Peak Internal Demand and Energy Requirements Prior to Adjusting for Filed DSM Programs 2009-2023						
	KPCo			Regulated AEP-East System		
	Peak Internal Demand		Internal Energy Req'ts (GWh)	Peak Internal Demand		Internal Energy Req'ts (GWh)
Year	Summer (MW)	Winter Following (MW)		Summer (MW)	Winter Following (MW)	
2009	1,309	1,640	7,964	21,131	20,419	123,713
2010	1,338	1,669	8,146	21,297	21,818	122,601
2011	1,357	1,674	8,290	22,619	22,033	133,003
2012	1,364	1,691	8,358	22,849	22,302	134,520
2013	1,379	1,702	8,420	23,131	22,475	135,649
2014	1,390	1,713	8,475	23,336	22,634	136,589
2015	1,400	1,719	8,533	23,534	22,725	137,544
2016	1,408	1,730	8,596	23,677	22,877	138,561
2017	1,420	1,741	8,654	23,906	23,017	139,430
2018	1,431	1,751	8,710	24,084	23,154	140,260
2019	1,441	1,756	8,765	24,257	23,216	141,051
2020	1,448	1,773	8,819	24,370	23,441	141,861
2021	1,462	1,785	8,877	24,614	23,614	142,780
2022	1,474	1,793	8,943	24,821	23,734	143,832
2023	1,483	1,800	9,009	25,023	23,849	144,942
% Average Growth Rate, 2009-2023	0.9	0.7	0.9	1.2	1.1	1.1
Note: Regulated AEP-East System Peak Internal Demands indicated above include "traditional" interruptible/non-firm loads, which are assumed to aggregate to 591 MW (summer) and 605 MW (winter) throughout the forecast period. KPCo has no such loads.						

E. DSM PROGRAMS AND IMPACTS (807 KAR 5:058 Sec. 5.4)

KPCo has offered a variety of conservation and demand-side management programs designed to encourage customers to use electricity efficiently, achieve energy conservation, and reduce the level of future peak demands for electricity since 1994. As a result of KPCo's DSM programs the AEP System - East Zone has realized an annual energy savings of approximately 8 GWh and peak demand reductions of approximately 8 MW in winter and approximately 8 MW in summer were achieved by the end of 2008. Through 2008 KPCo was the only AEP-East Zone operating company that had active traditional DSM programs. For future years, AEP System - East Zone will continue to experience the load impact benefits from these traditional DSM programs, and these load impacts are "embedded" in the base load forecast of the integrated resource plan. Additionally, all AEP - East Zone companies (including KPCo) continue to provide peak demand options, such as interruptible contracts, time-of-day and real time pricing tariffs.

AEP System - East Zone anticipates significantly expanding the base of demand-side programs within its footprint. Within the AEP-East operating zone, legislation in Ohio and Michigan require significant programs beginning in 2009. Internally, AEP has embraced peak demand reductions of 1,000 MW by year-end 2012 and energy reductions of 2,250 GWh for the entire AEP System, approximately 60-65% of which is in the AEP-East Zone. Further, pending national CO_2 legislation has made the economics of energy efficiency more compelling.

The level of DSM activity in each AEP-East Zone jurisdiction will vary, depending on the regulatory climate, various economic factors, such as potential program participation and cost-effectiveness, and the DSM cost recovery mechanisms in that jurisdiction. This IRP contemplates for KPCo an approximately prorated share of the AEP-East Zone's DSM level. The future programs that are modeled, within the context of the IRP, are "generic" in that the impacts are representative of programs that may be offered in other AEP-East Zone jurisdictions. To achieve the results represented in this IRP, KPCo will have to significantly expand its portfolio offerings to include more programs, especially in the commercial and industrial classes.

This IRP contemplates demand response programs that would primarily effect peak demand reduction in the summer in order to reduce capacity requirements within the PJM market.

The Company has been continually working with the KPCo DSM Collaborative (which was established in November 1994 to develop KPCo's DSM plans) to ensure that DSM programs are implemented as effectively and efficiently as possible and are helping Kentucky customers save energy. Over the years, the KPCo DSM Collaborative has worked closely in reviewing, recommending and endorsing DSM programs for Kentucky Power customers. Through continuously monitoring the program performance, program participation level and DSM market potential, the Collaborative has recommended the addition, deletion and modification of various DSM programs. These past and present programs, along with DSM programs proposed by the Collaborative for a three-year extension beyond 2008, are described in detail in the KPCo DSM Collaborative Semi-Annual Status Report and Program Evaluation Reports filed with the Commission on August 25, 2008. The Company has received Commission approval, by order dated November 25, 2008 in Case No. 2008-00350, to continue the KPCo Collaborative DSM programs through 2011. The development of KPCo's DSM programs by the Collaborative incorporated the Collaborative's perspectives on those aspects of integrated resource planning that related to demand-side management.

Table 4 lists the existing DSM programs that are currently being offered in Kentucky. This table includes those DSM programs that were approved by the Commission for a three-year extension beyond 2008 and the three new programs approved by the Commission on February 24, 2009.

TABLE 4
KPCo
Existing DSM Programs
Residential Programs:
1. Targeted Energy Efficiency Program (Low-Income Weatherization)
2. High-Efficiency Heat Pump - Mobile Home Program
3. Mobile Home New Construction Program
4. Modified Energy Fitness Program
5. High Efficiency Heat Pump Program
6. Energy Education for Students Program
7. Community Outreach Compact Fluorescent Lighting (CFL) Programs

Table 5 provides a summary of the estimated load impacts of implementing the expanded DSM programs for the AEP-East Zone and KPCo for the years 2009 to 2020, based on the market penetration rates assumed. It was also assumed that there would be no new DSM program participants after the year 2015. Thus, for KPCo, the expanded DSM programs would reduce the base forecast of peak internal demand for the winter season of 2015/16 by an estimated 20 MW (0.2%). In comparison, the summer 2015 peak demand would be reduced by 86 MW.

As Table 5 indicates, the DSM impacts increase through about the year 2015 and remain stable through the planning period. The assumption is that programs will continue to be funded to maintain this level of relative efficiency and peak demand reduction.

The expanded DSM program impacts shown in Table 5 are in addition to the impacts of DSM program installations already in place, i.e., the DSM measures implemented prior to 2009. Such "embedded" DSM impacts are already reflected in the base load forecast. Estimates of these embedded DSM program impacts as of the end of 2008 are shown in the bottom portion of Table 5.

Table 5

KPCo and AEP-East Zone
Estimated Load Impacts of Expanded and Filed DSM Programs
2009-2023

	KPCo			AEP-East Zone		
	Demand Reduction			Demand Reduction		
Year	Summer (MW)	Winter (MW)	Energy Reduction (GWh)	Summer (MW)	Winter (MW)	Energy Reduction (GWh)
2009	0	1	1	54	148	183
2010	18	2	38	316	225	836
2011	37	9	77	609	371	1607
2012	49	16	88	791	441	1967
2013	61	18	98	971	514	2325
2014	74	20	109	1152	582	2682
2015	86	22	119	1331	578	3037
2016	86	24	119	1327	578	3037
2017	86	24	119	1328	581	3037
2018	86	24	119	1329	582	3037
2019	86	23	119	1331	582	3037
2020	86	23	119	1331	576	3037
2021	86	24	119	1329	577	3037
2022	86	24	119	1327	576	3037
2023	86	24	119	1328	578	3037

Note: Expanded and Filed DSM program impacts result from installations assumed to be made in the future. Impacts of DSM program installations already in-place, i.e., embedded DSM program impacts, are reflected in the base load forecast.

As of the end of 2008, the estimated aggregate embedded DSM program impacts were as follows:

	Summer MW	Winter MW	Annual GWh
KPCo	8	8	8
AEP-East Zone	8	8	8

F. SUPPLY-SIDE RESOURCE EXPANSION (807 KAR 5:058 Sec. 5.4.)

The supply-side expansion plan represented in this report is influenced by the AEP System - East Zone's commitment to both DSM programs and renewables and, to a lesser extent, to the need for compliance with environmental regulations.

As described above, DSM programs are expected to reduce the KPCo peak and energy requirements by 86 MW and 119 GWh by the end of the planning period (2023). KPCo's participation in the renewables program is represented by the purchase of the output of two, 50 MW nameplate wind energy projects, one by year-end 2010 and the other by year-end 2011. The renewables program for KPCo also includes cofiring biomass in Rockport units 1 and 2 by 2013; separate injection of biomass in Big Sandy Unit 2 by 2015; and separate injection of biomass in Rockport Unit 1 by 2023. The two separate injection systems are expected to have substantial auxiliary load requirements (currently estimated to be 25 MW and 41 MW, respectively).

Conventional units that form part of an optimal plan for KPCo include 342 MW of peaking capacity (modeled as natural gas-fired combustion turbines) in 2018 and 360 MW of intermediate capacity (modeled as natural gas-fired combined cycle capacity) in 2023.

Major new environmental controls consist of flue gas desulfurization (FGD) systems at Big Sandy Unit 2 (2015) Rockport Unit 1 (2017), and Rockport Unit 2 (2019) for SO_2 emission reduction as well as activated carbon injection captured by the existing electrostatic precipitator at Rockport Units 1 and 2 in 2009 to reduce mercury emissons. The auxiliary load requirements of the (FGD) retrofits are expected to be offset by efficiency improvements brought about by steam valve replacements.

Table 6 compares projected demands net of expanded DSM with the projected capacity for the AEP System-East Zone and KPCo and presenting the resulting reserve margins. The data are shown for the winter, which is KPCo's peak season.

Table 6

Projected Peak Demands, Generating Capabilities and Margins At Time of Winter Peak 2009 – 2023								
	AEP System - East Zone				KPCo			
Year	Peak Demand(1) (MW)	Capability (MW) (2)	Reserve (MW)	Margin (%)	Peak Demand(1) (MW)	Capability (MW) (2)	Reserve (MW)	Margin (%)
2009	21,387	27,107	5,720	26.7%	1,629	1,336	-293	-18.0%
2010	21,275	28,048	6,773	31.8%	1,647	1,381	-266	-16.2%
2011	22,053	27,434	5,381	24.4%	1,654	1,387	-267	-16.1%
2012	22,114	27,670	5,556	25.1%	1,656	1,400	-256	-15.5%
2013	22,313	28,269	5,956	26.7%	1,671	1,474	-197	-11.8%
2014	22,413	28,941	6,528	29.1%	1,680	1,475	-205	-12.2%
2015	22504	28576	6,072	27.0%	1689	1451	-238	-14.1%
2016	22,598	28,165	5,567	24.6%	1,695	1,412	-283	-16.7%
2017	22,750	28,301	5,551	24.4%	1,706	1,412	-294	-17.2%
2018	22,888	27,739	4,851	21.2%	1,717	1,412	-305	-17.8%
2019	23,024	27,910	4,886	21.2%	1,728	1,754	26	1.5%
2020	23,086	27,444	4,358	18.9%	1,732	1,754	22	1.3%
2021	23316	27303	3,987	17.1%	1749	1754	5	0.3%
2022	23,489	27,407	3,918	16.7%	1,762	1,754	-8	-0.5%
2023	23,601	28,062	4,461	18.9%	1,769	1,748	-21	-1.2%

Notes: (1) After curtailment of interruptible loads.
(2) Includes generating facilities as shown in Exhibit 4-11 or 4-13.

Inasmuch as there are many assumptions, each with its own degree of uncertainty, which had to be made in carrying out the resource evaluations, changes in these assumptions could result in significant modifications in the resource plan reflected in Table 6. In this respect, sensitivity analyses indicated that the resource plan is sufficiently flexible to accommodate possible changes in key parameters, including load growth. As such changes are recognized, updated, and more refined, input information must be continually evaluated and resource plans modified as appropriate.

F.1. KPCo STAND ALONE (807 KAR 5:058 Sec. 5.4)

On page 5, of the Commission's Order dated December 13, 2004 in Case No. 2004-00420, "In the Matter of: Application of Kentucky Power Company for Approval of a Stipulation and Settlement Agreement Resolving State Regulatory Matters" (commonly referred to as the Rockport Settlement Agreement), the Company was directed that its next IRP should reflect the resources available to Kentucky Power as a "stand-alone" utility, as well as the resources available to it as a member of any power-pooling arrangement that is anticipated to exist during the period reflected in the IRP.

In fulfilment of that directive please see Exhibits 4-2, 4-8, 4-12, and 4-13, all of which identify the resources available to KPCo as a stand-alone utility and Exhibits 4-2, 4-7, 4-10, and 4-11 that identify the resources available to the AEP System-East Zone of which KPCo is a member.

As shown on Exhibit 4-12, KPCo's resources as a stand-alone utility include the Big Sandy plant and KPCo's shares of Rockport units 1 and 2. Future supply-side resources include two proposed wind energy power purchase agreements of 50 MW nameplate each. The plan includes over 300 MW of peaking capacity in 2018 and about 300 MW of intermediate capacity in 2023. Projected demand-side resources amount to 86 MW at the summer peak and 24 MW at the winter peak by 2015. Given these resources, as a stand-alone utility KPCo would have negative reserve margins through 2017. The addition of the peaking capacity would bring the reserve margin into the vicinity of zero. Given the large size of Big Sandy Unit 2 relative to KPCo, a large but undetermined reserve margin would be required by KPCo as a stand-alone utility. If 20% were required, then KPCo would need an additional 800 MW of capacity beyond the current plan in the near term and 400 MW after 2018. If KPCo as a stand-alone utility were a member of the PJM Interconnection, it would need to maintain a reserve margin of about 12% to 16% in the summer. As can be determined from Exhibit 4-12, KPCo as a stand-alone utility and a member of the PJM Interconnection would be required to either install additional generation capacity or purchase capacity from the PJM Interconnection earlier than it does as a member of the AEP-East Pool.

G. SIGNIFICANT CHANGES FROM THE PREVIOUS IRP FILING (807 KAR 5:058 Sec. 6)

Background: Kentucky Power Company filed an IRP on November 15, 2002 (Case No. 2002-00377). On March 3, 2003, the Commission issued an order placing the case in abeyance. On February 28, 2005, the parties to the case filed a joint motion to dismiss, citing the fact that KPCo's 2002 IRP was based on a three-member pool which did not materialize. The motion also cited the extension of the Rockport purchase power contract which was not reflected in the 2002 IRP. Finally, the motion stated that the requirement in the Commission's December 13, 2004 Order in Case No. 2004-00420 (Rockport extension) required Kentucky Power file its next IRP no later than June 30, 2009 [later extended to August 17, 2009]. The December 13th Order stated that Kentucky Power Company's 2002 IRP is considered ineffective as a planning document. For these reasons, Kentucky Power's previous IRP filing for purposes of this report is the October 19, 1999 Report filed in Case No. 99-437.

Significant Changes from 1999 to 2009 are as follow by major function:

Load Forecast

In the 10 years since the last IRP filing for the Company, there have been many changes to the customer base in Kentucky. For example, the residential customer growth has essentially ceased. In addition, Congress has passed legislation that greatly affects appliance efficiency. These, along with other factors, have resulted in a lowered load forecast. To better evaluate and account for efficiency trends and mandates, the Company now utilizes the Statistically Adjusted End-use model to forecast residential and commercial energy. See Chapter 2., Sec. I. for further details.

Resource Planning

With regards to the resource planning aspect of this IRP report the following changes have been addressed in this report:

- Entrance of the AEP System - East Zone into the PJM RTO – see Chapter 4, Sections B.1, B.2., and D.1.
- Advent of federal legislation Energy Independence and Security Act (EISA) and Energy Policy Act (EPAct) and proposals for green house gas limits – see Chapter 4, Sections B.3. and C.2.c.
- Tightening of power market conditions – see Chapter 4, Section C.4.a.
- Supply Side Plan – see comparison in Exhibit 4-15. The plan has changed from a general market orientation to a mix of specific renewable and traditional supplies described in Section F. above.

DSM

Since the last IRP submitted in 1999, the utility landscape has changed significantly. Energy costs have increased, improving the economics of demand-side management, from the prospective of the utility and the consumer. Federal initiatives have revitalized efforts in this area. This plan shows (Exhibit 3-1) a five-fold increase in energy savings attributable to expanded DSM programs in 2010 relative to the 1999 plan. Chapter 3 discusses in greater detail the process used to determine an appropriate level of prospective demand-side programs.

Transmission

From a transmission perspective, there are two significant changes between the 2009 IRP filing and KPCo's last IRP filing in 1999. First, at the time of the 1999 IRP filing, AEP System - East Zone was not a member of a Regional Transmission Organization or RTO. However, as indicated above the AEP System - East Zone became a member of the PJM Interconnection, LLC in 2004, at which time it transferred functional control of transmission facilities in the Eastern part of its system to the PJM Interconnection, LLC. AEP System - East Zone retains operational responsibility for those facilities that are not under PJM functional control, and is involved in the various operations, and planning stakeholder processes of PJM to help ensure the reliability of the transmission system.

The other significant change pertains to the Wyoming-Jacksons Ferry project, which at the time of the 1999 IRP filing, was an alternative to the originally proposed Wyoming-Cloverdale 765-kV line. However, as referenced in Chapter 4 of the current IRP filing, the Wyoming-Jacksons Ferry line was completed and in-service in 2006.

Environmental Compliance

In addition to the compliance strategy for meeting the CAAA Title IV (Acid Rain Program) Phase I and II emission requirements for SO_2 and NO_X included in its 1999 IRP, since then AEP and its operating companies (including Kentucky Power Company) have developed additional strategies to meet the requirements of the Clean Air Act (CAA) and its Amendments (CAAA) as each rule became known. These rules included the NO_X State Implementation Plan (SIP) Call, Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR). In addition to compliance with CAAA rules, on October 9, 2007, AEP entered into a consent decree with the Department of Justice to settle all complaints filed against AEP and its affiliates under the New Source Review (NSR) program of the Clean Air Act. Looking beyond existing CAAA rules, the electric utility industry, as a major producer of CO_2, will be significantly affected by any green house gas (GHG) legislation. Details of AEP's strategy for compliance with the NSR Consent Decree, each CAAA rule as it became effective, and proposed GHG legislation are provided in Section B.3 of Chapter 4.

Fuel Procurement

There have been no significant changes in the area of fuel procurement practices since the 1999 IRP report.

H. FINANCIAL INFORMATION (807 KAR 5:058 Sec. 9)

In accordance with Section 9 of the IRP Regulations that requests certain financial information be provided, please see Table 7 that follows:

Table 7
KENTUCKY POWER COMPANY
INTEGRATED RESOURCE PLAN
FINANCIAL INFORMATION
($ Millions)

Year	Nominal Value of Revenue Requirements	Discount Rate	Present Value of Revenue Requirements	Real Value of Revenue Requirements	Average Rate (Cents/kWh)
2009	486	11.78%	486	486	6.64
2010	542	11.78%	485	532	7.12
2011	600	11.78%	480	579	7.67
2012	601	11.78%	431	570	7.46
2013	610	11.78%	391	568	7.37
2014	638	11.78%	366	584	7.52
2015	683	11.78%	350	613	7.85
2016	707	11.78%	324	624	7.94
2017	723	11.78%	297	627	7.91
2018	759	11.78%	279	647	8.11
2019	801	11.78%	263	670	8.35
2020	819	11.78%	240	673	8.33

Notes:

(1) Present values are calculated using a mid-year convention along with KPCo's discount rate (shown above).

(2) Real dollar values are calculated using an inflation rate of 1.8%. This rate is estimated to be an average for all customers.

(3) Discount Rate based on incremental pretax weighted average cost of capital.

(4) Average rate calculated by dividing Real Value of Revenue Requirements by Internal GWh Sales.

(5) Data is only available through 2020.

I. NEXT STEPS, KEY ISSUES/UNCERTAINTIES

I.1. Implementation Steps (807 KAR 5:058 Sec. 5.5)

Steps to be taken during the next three (3) years to implement the plan are as follows:

Wind Projects

The expansion plan in this report for KPCo includes 50-MW (nameplate) wind resources to be in place by year-end 2010 and year-end 2011. On June 1, 2009 AEP issued a Request for Proposals for up to 1,100 MW (nameplate) of renewable power, with commercial operating dates between January 1, 2008 and December 31, 2011. Pre-bid meetings have been held. Proposals for projects expected online by the end of 2010 are due August 31; those expected online by the end of 2011 are due January 15, 2010. Proposals will be evaluated and short-listed bidders will be notified 45 days after the bid due date. Post-bid negotiations then will cover both price and non-price issues. It is expected that, with this schedule, contracts for the capacity assigned to KPCo can be signed expeditiously and the power received as planned. Contracts pertaining to KPCo are subject to Commission approval.

DSM Goals Imbedded in the IRP

To achieve the DSM goals imbedded in the IRP, KPCo will need to obtain customer acceptance and participation in the new and expanded DSM programs in all three sectors (residential, commercial and industrial). Currently, the DSM Collaborative is represented by the residential sector only, therefore, KPCo will vigorously endeavor to re-establish representation of both the commercial and industrial sectors. When the DSM Collaborative is represented by all three sectors, the Collaborative will need to develop new and expanded cost effective DSM programs relative to all three sectors. Once the Collaborative has developed the new and expanded cost effective programs, Commission approval will need to be obtained. Only then can the DSM programs be activated and the benefits from the new and expanded cost effective programs begin to be realized.

Load Forecasting

With regards to load forecasting, KPCo will continue to evaluate and incorporate the effects of the economy and the energy efficiency programs including federal mandates and expanded energy efficiency programs.

I.2. Key Issues/Uncertainties (807 KAR 5:058 Sec. 5.6)

Key issues or uncertainties that could affect successful implementation of the plan are as follows:

Resource Planning

The plan represented in this report meets the objectives mentioned above, having planning flexibility and adaptability to risk. KPCo's supply-side plan does not entail much risk or uncertainty. Perhaps the uncertainty presenting the largest change, though not likely to occur, would be the catastrophic failure of Big Sandy Unit 1. This unit, now 46 years old, has few environmental controls compared to many newer and larger units, making it relatively costly to operate from an emission allowance standpoint. A catastrophic failure would bring about a careful evaluation of the viability of any plan to repair and return it to service. A decision to not repair the unit after such a failure would bring forward in time the need for major, new generating facilities for KPCo.

DSM

In the area of DSM the key issues and/or uncertainties are 1) the degree of customer acceptance of offered DSM programs. Achieving the high levels of energy efficiency and demand response will require customers to embrace these efforts in unprecedented numbers; 2) the impact on ratepayer and their ability to fund DSM programs. Ramping up customer participation to achieve planning levels will require up-front investment by ratepayers (i.e., they will see increased bills); and 3) whether or not in today's economic climate regulators will approve the increase spending that accompanies increasing levels of implementation of utility sponsored DSM programs due to its impact upon customers' bills.

Load Forecasting

A major uncertainty is how strong will the economy be in the future. The economy has a direct impact on the Company's load.

The Company provides a broad overview of a high and low economic forecast scenario. See Chapter 2.H. for more details.

Transmission

As a result of the AEP - East Zone transmission system's geographical location and expanse, as well as its numerous interconnections, the AEP-East Zone transmission system can be influenced by both internal and external factors. Facility outages, load changes, or generation redispatch on neighboring companies' systems, in combination with power transactions across the interconnected network, can affect power flows on AEP's eastern transmission facilities. As a result, the eastern transmission system is designed and operated to perform adequately even with the outage of its most critical transmission elements or the unavailability of generation. The AEP - East Zone transmission system conforms to the NERC Reliability Standards and the applicable Reliability*First* Corporation standards and performance criteria.

The AEP - East Zone transmission system assets are aging and some station equipment is becoming obsolete. Therefore, in order to maintain acceptable levels of reliability, significant investments will have to be made over the next ten years to proactively replace the most critical aging and obsolete equipment and transmission lines.

Environmental Compliance

Currently the CAIR, which became effective in July 2005 and called for significant reductions of NO_X and SO_2, beginning in 2009 and 2010, respectively, has been remanded by the D.C. Circuit Court to the EPA for further rulemaking in response to legal appeals of this rule. While EPA addresses the deficiencies identified by the Court, the compliance requirements of CAIR remain in effect. There is a great deal of uncertainty over what approach EPA will take to rewrite the CAIR and its associated compliance requirements. For purposes of planning, the AEP System expects the CAIR program to be replaced with a more restrictive policy.

The CAMR, which also became effective in July 2005, has been vacated by the D.C. Circuit Court, eliminating any compliance requirements for mercury until EPA develops a new rule. Federal action is anticipated and could become effective in 2014 when a command-and-control policy could require all coal units to install either a mercury-specific control technology such as activated carbon injection or FGD/SCR emissions control equipment. This scenario could have an impact on proposed retirement dates of older, non-controlled units and ultimately the timing for new capacity.

Finally, on-going debate over CO_2/GHG emissions, particulate matter, and regional haze (CAVR) will likewise influence future capacity resource planning surrounding decisions to retrofit, modify operations, or retire/mothball generating assets.

Coal Market Uncertainties

Coal market price volatility has increased due to various events affecting the supply and demand posture of coal in the international markets. Various countries have lessened their previously stated export coal quantities to rebuild domestic stockpiles, which caused all international coal markets to tighten and prices to rise significantly. Additionally, the decreased value of the U.S. dollar relative to most major foreign currencies contributed to the U.S. coal being more competitive based on price in the international export market. There also has been an increasingly strong demand for coal world wide, especially in emerging economies, along with sustained coal consumption in the United States. Early last year the global demand for coal seemed insatiable and that demand placed a significant upward pressure on the price of coal. Conversely, since last fall, there was a slow down in the world and U.S. economies, that reduced demand for U.S. coal and has effectively lowered the market price.

KPCo coal purchase strategy will continue to manage market volatility utilizing a variety of market analysis techniques and periodic solicitations for spot and longer term coal purchases with each successive long-term arrangement layered onto the base of existing long-term contracts. Spot offers can address KPCo's other needs. Throughout all market conditions, KPCo will maintain adequate deliveries of coal to the Big Sandy generating station recognizing its goal of obtaining the lowest reasonable delivered cost over a period of years consistent with the obligations of the Company to provide adequate and reliable service to its customers and meet environmental standards.

J. CROSS REFERENCE TABLE (807KAR5:058 SECTION 4, FORMAT);

Kentucky Power has included a Cross Reference Table below that lists the section and sub-section numbers found in Administrative Regulation 807KAR5:058 "Integrated Resource Planning by Electric Utilities" along with the corresponding report Sections and/or Exhibits of Kentucky Power's IRP Plan. This Cross Reference Table is provided in order to satisfy Section 4 of the IRP regulation.

Cross Reference Table
IRP Regulation (807 KAR 5:058)

Report Reference

807 KAR 5:058. Integrated resource planning by electric utilities	
Section 1. General Provisions	
(1) This administrative regulation shall apply to electric utilities under commission jurisdiction except a distribution company with less than $10,000,000 annual revenue or a distribution cooperative organized under KRS Chapter 279.	
(2) Each electric utility shall file triennially with the commission an integrated resource plan. The plan shall include historical and projected demand, resource, and financial data, and other operating performance and system information, and shall discuss the facts, assumptions, and conclusions, upon which the plan is based and the actions it proposes.	
(3) Each electric utility shall file ten (10) bound copies and one (1) unbound, reproducible copy of its integrated resource plan with the commission.	
Section 2. Filing Schedule. (1) Each electric utility shall file its integrated resource plan according to a staggered schedule which provides for the filing of integrated resource plans one (1) every six (6) months beginning nine (9) months from the effective date of this administrative regulation.	
(a) The integrated resource plans shall be filed at the specified times following the effective date of this administrative regulation:	
1. Kentucky Utilities Company shall file nine (9) months from the effective date;	
2. Kentucky Power Company shall file fifteen (15) months from the effective date;	In compliance with the KPSC's Order in Case No. 2004-00420 dated 2-23-09 the Company will file before 8-17-09
3. East Kentucky Power Cooperative, Inc. shall file twenty-one (21) months from the effective date;	
4. The Union Light, Heat & Power Company shall file twenty-seven (27) months from the effective date;	
5. Big Rivers Electric Corporation shall file thirty-three (33) months from the effective date; and	
6. Louisville Gas & Electric Company shall file thirty-nine (39) months from the effective date.	
(b) The schedule shall provide at such time as all electric utilities have filed integrated resource plans, the sequence shall repeat.	
(c) The schedule shall remain in effect until changed by the commission on its own motion or on motion of one (1) or more electric utilities for good cause shown. Good cause may include a change in a utility's financial or resource conditions.	
(d) If any filing date falls on a weekend or holiday, the plan shall be submitted on the first business day following the scheduled filing date.	
(2) Immediately upon filing of an integrated resource plan, each utility shall provide notice to intervenors in its last integrated resource plan review proceeding, that its plan has been filed and is available from the utility upon request.	The Company intends to comply with this requirement.
(3) Upon receipt of a utility's integrated resource plan, the commission shall establish a review schedule which may include interrogatories, comments, informal conferences, and staff reports.	

Cross Reference Table
IRP Regulation (807 KAR 5:058)

IRP Regulation (807 KAR 5:058)	Report Reference
Section 3. Waiver. A utility may file a motion requesting a waiver of specific provisions of this administrative regulation. Any request shall be made no later than ninety (90) days prior to the date established for filing the integrated resource plan. The commission shall rule on the request within thirty (30) days. The motion shall clearly identify the provision from which the utility seeks a waiver and provide justification for the requested relief which shall include an estimate of costs and benefits of compliance with the specific provision. Notice shall be given in the manner provided in Section 2(2) of this administrative regulation.	No Waivers have been requested.
Section 4. Format	
(1) The integrated resource plan shall be clearly and concisely organized so that it is evident to the commission that the utility has complied with reporting requirements described in subsequent sections.	Chapter 1.J. - Cross-reference Table
(2) Each plan filed shall identify the individuals responsible for its preparation, who shall be available to respond to inquiries during the commission's review of the plan.	Direct Inquiries to Errol Wagner, KPCO's Director of Rates. The lead preparers for Chapters 2, 3, and 4 are Randy Holliday (Economic Forecasting), William Castle (Resource Planning - DSM) and Donald Schlegei (Resource Planning - Supply/Integration), respectively.
Section 5. Plan Summary	
The plan shall contain a summary which discusses the utility's projected load growth and the resources planned to meet that growth. The summary shall include at a minimum:	Chapter 1
(1) Description of the utility, its customers, service territory, current facilities, and planning objectives;	Chapter 1.B. and Chapter 1.C.
(2) Description of models, methods, data, and key assumptions used to develop the results contained in the plan;	Chapter 1.D. , Chapter 2 Section A.1. B. C. and D.
(3) Summary of forecasts of energy and peak demand, and key economic and demographic assumptions or projections underlying these forecasts;	Chapter 1.D.
(4) Summary of the utility's planned resource acquisitions including improvements in operating efficiency of existing facilities, demand-side programs, nonutility sources of generation, new power plants, transmission improvements, bulk power purchases and sales, and interconnections with other utilities;	Chapter 1, Sections D, E and F and Chapter 4.D.1.and Exhibit 4-18
(5) Steps to be taken during the next three (3) years to implement the plan;	Chapter 1.I.1.
(6) Discussion of key issues or uncertainties that could affect successful implementation of the plan.	Chapter 1.I.2.
Section 6. Significant Changes	
All integrated resource plans, shall have a summary of significant changes since the plan most recently filed. This summary shall describe, in narrative and tabular form, changes in load forecasts, resource plans, assumptions, or methodologies from the previous plan. Where appropriate, the utility may also use graphic displays to illustrate changes.	Chapter 1.G. and Chapter 2.I.and Chapter 3.A.1.and Exhibit 4-15
Section 7. Load Forecasts	
The plan shall include historical and forecasted information regarding loads.	Chapter 2.E.1 and Chapter 2.E.2
(1) The information shall be provided for the total system and, where available, disaggregated by the following customer classes:	Chapter 2.E.1 & Chapter 2.E.2 note Residential forecast in aggregate
(a) Residential heating;	Chapter 2.J.
(b) Residential nonheating;	Chapter 2.J.
(c) Total residential (total of paragraphs (a) and (b) of this subsection);	Chapter 2.E.1 and E.2
(d) Commercial;	Chapter 2.E.1 and E.2

Cross Reference Table IRP Regulation (807 KAR 5:058)	Report Reference
(e) Industrial;	Chapter 2.E.1 and E.2
(f) Sales for resale;	Chapter 2.E.1 and E.2
(g) Utility use and other.	Chapter 2.E.1 and E.2
The utility shall also provide data at any greater level of disaggregation available.	Chapter 2.E.1 and E.2
(2) The utility shall provide the following historical information for the base year, which shall be the most recent calendar year for which actual energy sales and system peak demand data are available, and the four (4) years preceding the base year:	
(a) Average annual number of customers by class as defined in subsection (1) of this section;	Chapter 2.J.
(b) Recorded and weather-normalized annual energy sales and generation for the system, and sales disaggregated by class as defined in subsection (1) of this section;	Chapter 2.J.
(c) Recorded and weather-normalized coincident peak demand in summer and winter for the system;	Chapter 2.J.
(d) Total energy sales and coincident peak demand to retail and wholesale customers for which the utility has firm, contractual commitments;	Chapter 2.J.
(e) Total energy sales and coincident peak demand to retail and wholesale customers for which service is provided under an interruptible or curtailable contract or tariff or under some other nonfirm basis;	Chapter 2.J.
(f) Annual energy losses for the system;	Chapter 2.J.
(g) Identification and description of existing demand-side programs and an estimate of their impact on utility sales and coincident peak demands including utility or government sponsored conservation and load management programs;	Chapter 2.E.2; Chapter 3.A.2; Chapter 3 Appendix
(h) Any other data or exhibits, such as load duration curves or average energy usage per customer, which illustrate historical changes in load or load characteristics.	Chapter 2.J
(3) For each of the fifteen (15) years succeeding the base year, the utility shall provide a base load forecast it considers most likely to occur and, to the extent available, alternate forecasts representing lower and upper ranges of expected future growth of the load on its system. Forecasts shall not include load impacts of additional, future demand-side programs or customer generation included as part of planned resource acquisitions estimated separately and reported in Section 8(4) of this administrative regulation. Forecasts shall include the utility's estimates of existing and continuing demand-side programs as described in subsection (5) of this section.	Chapter 2.E.1 and E.2
(4) The following information shall be filed for each forecast:	
(a) Annual energy sales and generation for the system and sales disaggregated by class as defined in subsection (1) of this section;	Chapter 2.E.1 and E.2
(b) Summer and winter coincident peak demand for the system;	Chapter 2.E.1 and E.2
(c) If available for the first two (2) years of the forecast, monthly forecasts of energy sales and generation for the system and disaggregated by class as defined in subsection (1) of this section and system peak demand;	Chapter 2.E.1 and E.2
(d) The impact of existing and continuing demand-side programs on both energy sales and system peak demands, including utility and government sponsored conservation and load management programs	Chapter 2.E.1 and E.2, Chapter 2.F.
(e) Any other data or exhibits which illustrate projected changes in load or load characteristics.	Chapter 2.C.3.b and 2.C.3.c
(5) The additional following data shall be provided for the integrated system, when the utility is part of a multistate integrated utility system, and for the selling company, when the utility purchases fifty (50) percent of its energy from another company:	
(a) For the base year and the four (4) years preceding the base year	
1. Recorded and weather normalized annual energy sales and generation;	Chapter 2.J.

Cross Reference Table IRP Regulation (807 KAR 5:058)	Report Reference
2. Recorded and weather-normalized coincident peak demand in summer and winter.	Chapter 2.J.
(b) For each of the fifteen (15) years succeeding the base year:	
1. Forecasted annual energy sales and generation;	Chapter 2.E.1 and 2.E.2
2. Forecasted summer and winter coincident peak demand.	Chapter 2.E.1 and 2.E.2
(6) A utility shall file all updates of load forecasts with the commission when they are adopted by the utility.	Chapter 2.L.4
(7) The plan shall include a complete description and discussion of:	
(a) All data sets used in producing the forecasts;	Chapter 2 Appendix
(b) Key assumptions and judgments used in producing forecasts and determining their reasonableness;	Chapter 2.C and 2-D and Chapter 2 Appendix
(c) The general methodological approach taken to load forecasting (for example, econometric, or structural) and the model design, model specification, and estimation of key model parameters (for example, price elasticities of demand or average energy usage per type of appliance);	Chapter 2.B, 2.C and 2.D
(d) The utility's treatment and assessment of load forecast uncertainty;	Chapter 2.H.
(e) The extent to which the utility's load forecasting methods and models explicitly address and incorporate the following factors:	Chapter 2.C and Chapter 2 Appendix
1. Changes in prices of electricity and prices of competing fuels;	Chapter 2.C, 2.G and Chapter 2 Appendix
2. Changes in population and economic conditions in the utility's service territory and general region;	Chapter 2.C. and Chapter 2 Appendix
3. Development and potential market penetration of new appliances, equipment, and technologies that use electricity or competing fuels; and	Chapter 2.C. and Chapter 2 Appendix
4. Continuation of existing company and government sponsored conservation and load management or other demand-side programs.	Chapter 2.C. and Chapter 2 Appendix
(f) Research and development efforts underway or planned to improve performance, efficiency, or capabilities of the utility's load forecasting methods; and	Chapter 2.I.3.
(g) Description of and schedule for efforts underway or planned to develop end-use load and market data for analyzing demand-side resource options including load research and market research studies, customer appliance saturation studies, and conservation and load management program pilot or demonstration projects.	Chapter 2.J.
Technical discussions, descriptions, and supporting documentation shall be contained in a technical appendix.	Chapter 2 Appendix
Section 8. Resource Assessment and Acquisition Plan	
(1) The plan shall include the utility's resource assessment and acquisition plan for providing an adequate and reliable supply of electricity to meet forecasted electricity requirements at the lowest possible cost. The plan shall consider the potential impacts of selected, key uncertainties and shall include assessment of potentially cost-effective resource options available to the utility.	Chapter 4
(2) The utility shall describe and discuss all options considered for inclusion in the plan including:	
(a) Improvements to and more efficient utilization of existing utility generation, transmission, and distribution facilities;	Chapter 4.C.2.b.
(b) Conservation and load management or other demand-side programs not already in place;	Chapter 3.D and Chapter 3.E.
(c) Expansion of generating facilities, including assessment of economic opportunities for coordination with other utilities in constructing and operating new units; and	Chapter 4
(d) Assessment of nonutility generation, including generating capacity provided by cogeneration, technologies relying on renewable resources, and other nonutility sources.	Chapter 4.C.4.and Chapter 4.C.2.c.

Cross Reference Table
IRP Regulation (807 KAR 5:058)

	Report Reference
(3) The following information regarding the utility's existing and planned resources shall be provided. A utility which operates as part of a multistate integrated system shall submit the following information for its operations within Kentucky and for the multistate utility system of which it is a part. A utility which purchases fifty (50) percent or more of its energy needs from another company shall submit the following information for its operations within Kentucky and for the company from which it purchases its energy needs.	
(a) A map of existing and planned generating facilities, transmission facilities with a voltage rating of sixty-nine (69) kilovolts or greater, indicating their type and capacity, and locations and capacities of all interconnections with other utilities. The utility shall discuss any known, significant conditions which restrict transfer capabilities with other utilities.	Confidential Exhibits 4-16 & Confidential Exhibit 4-17
(b) A list of all existing and planned electric generating facilities which the utility plans to have in service in the base year or during any of the fifteen (15) years of the forecast period, including for each facility:	
1. Plant name; •	Exhibit 4-2 and Exhibits 4-10 through 4-13
2. Unit number(s);	Exhibit 4-2 and Exhibits 4-10 through 4-13
3. Existing or proposed location;	Exhibit 4-2 and Exhibits 4-10 through 4-13
4. Status (existing, planned, under construction, etc.);	Exhibit 4-2 and Exhibits 4-10 through 4-13
5. Actual or projected commercial operation date;	Exhibit 4-2 and Exhibits 4-10 through 4-13
6. Type of facility;	Exhibit 4-2 and Exhibits 4-10 through 4-13
7. Net dependable capability, summer and winter;	Exhibit 4-2 and Exhibits 4-10 through 4-13
8. Entitlement if jointly owned or unit purchase;	Exhibit 4-2 and Exhibits 4-10 through 4-13
9. Primary and secondary fuel types, by unit;	Exhibit 4-2 and Exhibits 4-10 through 4-13
10. Fuel storage capacity;	Exhibit 4-2 and Exhibits 4-10 through 4-13
11. Scheduled upgrades, deratings, and retirement dates;	Exhibits 4-10 through 4-13
12. Actual and projected cost and operating information for the base year (for existing units) or first full year of operations (for new units) and the basis for projecting the information to each of the fifteen (15) forecast years (for example, cost escalation rates). All cost data shall be expressed in nominal and real base year dollars.	
a. Capacity and availability factors;	Exhibits 4-5 and Confidential 4-6
b. Anticipated annual average heat rate;	Exhibits 4-5 and Confidential 4-6
c. Costs of fuel(s) per millions of British thermal units (MMBtu);	Exhibit 4-3 and Confidential Exhibit 4-4
d. Estimate of capital costs for planned units (total and per kilowatt of rated capacity);	Chapter 4.C.2.a. and Confidential Exhibit 4-9
e. Variable and fixed operating and maintenance costs;	Exhibit 4-3 and Confidential Exhibit 4-4
f. Capital and operating and maintenance cost escalation factors;	Chapter 4.C.5.b.
g. Projected average variable and total electricity production costs (in cents per kilowatt-hour).	Confidential Exhibit 4-4
(c) Description of purchases, sales, or exchanges of electricity during the base year or which the utility expects to enter during any of the fifteen (15) forecast years of the plan.	Exhibits 4-10 through 4-13
(d) Description of existing and projected amounts of electric energy and generating capacity from cogeneration, self-generation, technologies relying on renewable resources, and other nonutility sources available for purchase by the utility during the base year or during any of the fifteen (15) forecast years of the plan.	Chapter 4.C.4.a.and Chapter 4.C.2.a.
(e) For each existing and new conservation and load management or other demand-side programs included in the plan:	
1. Targeted classes and end-uses;	Chapter 3 Appendix; Chapter 3.E.5. and Exhibit 3-3
2. Expected duration of the program;	Chapter 3.E.7

Cross Reference Table
IRP Regulation (807 KAR 5:058)

	Report Reference
3. Projected energy changes by season, and summer and winter peak demand changes;	Chapter 3.E.6., Exhibit 3-4, and Chapter 3 Appendix, Filed DSM Programs see Chapters 2.F. and Chapter 2.E.2.
4. Projected cost, including any incentive payments and program administrative costs; and	Chapter 3 Appendix; Chapter 3.E.7. and Exhibit 3-5
5. Projected cost savings, including savings in utility's generation, transmission and distribution costs.	Chapter 3 E.7.,Chapter 3 Appendix
(4) The utility shall describe and discuss its resource assessment and acquisition plan which shall consist of resource options which produce adequate and reliable means to meet annual and seasonal peak demands and total energy requirements identified in the base load forecast at the lowest possible cost. The utility shall provide the following information for the base year and for each year covered by the forecast:	
(a) On total resource capacity available at the winter and summer peak:	
1. Forecast peak load;	Exhibits 4-10 through 4-13
2. Capacity from existing resources before consideration of retirements;	Exhibits 4-10 through 4-13
3. Capacity from planned utility-owned generating plant capacity additions;	Exhibits 4-10 through 4-13
4. Capacity available from firm purchases from other utilities;	Exhibits 4-10 through 4-13
5. Capacity available from firm purchases from nonutility sources of generation;	Exhibits 4-10 through 4-13
6. Reductions or increases in peak demand from new conservation and load management or other demand-side programs;	Exhibits 4-10 through 4-13, filed DSM Program Chapter 2.F. and Chapter 2.E.2. Also Exihibt 3-4
7. Committed capacity sales to wholesale customers coincident with peak;	Exhibits 4-10 through 4-13
8. Planned retirements;	Exhibits 4-10 through 4-13
9. Reserve requirements;	Exhibits 4-10 through 4-13
10. Capacity excess or deficit;	Exhibits 4-10 through 4-13
11. Capacity or reserve margin.	Exhibits 4-10 through 4-13
(b) On planned annual generation:	
1. Total forecast firm energy requirements;	Exhibit 4-14
2. Energy from existing and planned utility generating resources disaggregated by primary fuel type;	Exhibit 4-14
3. Energy from firm purchases from other utilities;	Exhibit 4-14
4. Energy from firm purchases from nonutility sources of generation; and	Exhibit 4-14
5. Reductions or increases in energy from new conservation and load management or other demand-side programs;	Exhibit 3-4 and Exhibit 4-14
(c) For each of the fifteen (15) years covered by the plan, the utility shall provide estimates of total energy input in primary fuels by fuel type and total generation by primary fuel type required to meet load. Primary fuels shall be organized by standard categories (coal, gas, etc.) and quantified on the basis of physical units (for example, barrels or tons) as well as in MMBtu.	Exhibit 4-14
(5) The resource assessment and acquisition plan shall include a description and discussion of	
(a) General methodological approach, models, data sets, and information used by the company;	Chapters 4.A., 4.C and 4.E.
(b) Key assumption and judgments used in the assessment and how uncertainties in those assumptions and judgments were incorporated into analyses;	Chapter 4.B.1.
(c) Criteria (for example, present value of revenue requirements, capital requirements, environmental impacts, flexibility, diversity) used to screen each resource alternative including demand-side programs, and criteria used to select the final mix of resources presented in the acquisition plan;	Chapters 4.A. and 4.E.
(d) Criteria used in determining the appropriate level of reliability and the required reserve or capacity margin, and discussion of how these determinations have influenced selection of options;	Chapter 4.B.2.
(e) Existing and projected research efforts and programs which are directed at developing data for future assessments and refinements of analyses;	Chapter 4.C.4.

Cross Reference Table IRP Regulation (807 KAR 5:058)	Report Reference
(f) Actions to be undertaken during the fifteen (15) years covered by the plan to meet the requirements of the Clean Air Act amendments of 1990, and how these actions affect the utility's resource assessment; and	Chapter 4.B.3.
(g) Consideration given by the utility to market forces and competition in the development of the plan.	Chapter 4.C.4.a.
Technical discussion, descriptions and supporting documentation shall be contained in a technical appendix.	Chapter 4 Technical Appendix
Section 9. Financial Information	
The integrated resource plan shall, at a minimum, include and discuss the following financial information:	
(1) Present (base year) value of revenue requirements stated in dollar terms;	Chapter 1.H. Financial Information, Table 7
(2) Discount rate used in present value calculations;	Chapter 1.H. Financial Information, Table 7
(3) Nominal and real revenue requirements by year; and	Chapter 1.H. Financial Information, Table 7
(4) Average system rates (revenues per kilowatt hour) by year.	Chapter 1.H. Financial Information, Table 7
Section 10. Notice	
Each utility which files an integrated resource plan shall publish, in a form prescribed by the commission, notice of its filing in a newspaper of general circulation in the utility's service area. The notice shall be published not more than thirty (30) days after the filing date of the report.	The Company intends to publish Notices on or before September 16th, 2009.
Section 11 Procedures for Review of the Integrated Resource Plan	
(1) Upon receipt of a utility's integrated resource plan, the commission shall develop a procedural schedule which allows for submission of written interrogatories to the utility by staff and intervenors, written comments by staff and intervenors, and responses to interrogatories and comments by the utility.	
(2) The commission may convene conferences to discuss the filed plan and all other matters relative to review of the plan.	
(3) Based upon its review of a utility's plan and all related information, the commission staff shall issue a report summarizing its review and offering suggestions and recommendations to the utility for subsequent filings.	
(4) A utility shall respond to the staff's comments and recommendations in its next integrated resource plan filing.	

2. LOAD FORECAST

2. LOAD FORECAST

A. SUMMARY OF LOAD FORECAST

A.1. Forecast Assumptions (807 KAR 5:058 Sec. 5.2.)

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 Moody's Economy.com. The load forecasts presented herein are based on a Moody's Economy.com economic forecast issued in October 2008 and on AEP load experience prior to 2009. Moody's Economy.com projects moderate growth in the U.S. economy during the 2009-2023 forecast period, characterized by a 2.7% annual rise in real Gross Domestic Product (GDP), and moderate inflation as well, with the consumer price index expected to rise by 1.9% per year. Industrial output, as measured by the Federal Reserve Board's (FRB's) index of industrial production, is expected to grow at 1.1% per year during the same period. For the regional economic outlook, the October 2008 forecast developed by Moody's Economy.com was utilized. The outlook for KPCo's service area projects employment growth of 0.2% per year during the forecast period and real regional income per-capita growth of 2.1%.

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, after consideration of the effects of filed DSM programs, are forecasted to increase at an average annual rate of 0.9% from 2009 to 2023. The corresponding summer and winter peak internal demands are forecasted to grow at an average annual rate of 0.9% and 0.7%, respectively. KPCo's annual peak demand is expected to continue to occur in the winter season.

The AEP-East Zone's internal energy requirements during the forecast period are projected to increase at an average annual rate of 1.1% between 2009 and 2023, after consideration of the effects of filed DSM. Summer and winter peak internal demands are expected to grow at average annual rates of 1.2% and 1.1%, respectively. The AEP-East Zone annual peak is projected to occur in the summer season.

The load effects of filed DSM generally increase in time through about the year 2011 and then remain relatively stable. Over the 15-year forecast period, the projected filed DSM has little effect on load growth. For both the AEP-East Zone 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 filed DSM, is unchanged from the growth rate without DSM. The effects of DSM programs beyond those have been filed will be discussed in Chapter 3.

B. OVERVIEW OF FORECAST METHODOLOGY (807 KAR 5:058 Sec. 5.2. and Sec. 7.7.c.)

KPCo's load forecasts are based mostly on econometric, supplemented with state-of-the-art statistically adjusted end-use, analyses of time-series data – producing an internally consistent forecast. This consistency is enhanced by model logic expressed in mathematical terms and quantifiable forecast assumptions. This is helpful when analyzing future scenarios and developing confidence bands. Additionally, econometric analysis lends itself to objective model verification by using standard statistical criteria. This is particularly helpful because it allows apples-to-apples comparisons of different companies and forecast periods.

In practice, econometric analysis highlights alternatives in forecasting models that may not be immediately obvious to the layperson. Likewise, professional judgment is required to interpret statistical criteria that are not always clear-cut. KPCo's analysts strive to interpret this data to produce as useful and as accurate a forecast as possible.

In pursuit of that goal, KPCo's energy requirements forecast is derived from two sets of econometric models: 1) a set of monthly short-term models and 2) a set of long-term models, with some using monthly data and others using annual data. 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, using billed or metered energy sales. The long-term sales are billed.

The short- and long-term forecasts are blended during the second six months of the second year of the forecast. The blending ensures a smooth transition from the short-term to the long-term forecast.

For those long-term forecasts that are quarterly, a monthly load shape is applied to the forecast based on analysis from the short-term models. The blended sales forecasts are converted to billed and accrued energy sales, which are consistent with the energy generated.

In both sets of models, the major energy classes are analyzed separately. Inputs such as regional and national economic conditions and demographics, energy prices, weather factors, special information such as known plans of specific major customers, and informed judgment are all used in producing the forecasts. The major difference between the two is that the short-term models use mostly trend, seasonal, and weather variables, while the long-term models use structural variables, such as population, income, employment, energy prices, and weather factors, as well as trends. Supporting forecasting models are used to predict some inputs to the long-term energy models. For example, natural gas models are used to predict sectoral natural gas prices that then serve as inputs.

Either directly, through national economic inputs to the forecast models, or indirectly, through inputs from supporting models, KPCo's load forecasts are influenced greatly by the outlook for the national economy. For the load forecasts reported herein, Moody's Economy.com's October 2008 forecast was used as the basis for that outlook. Moody's Economy.com's regional forecast, which is consistent with its national economic forecast, was used for the regional economic forecast of income, employment, households, output, and population.

The energy forecast for the AEP–East Zone, by customer class, is obtained by summing the forecasts, by customer class, of each of the AEP–East Zone operating companies. The same method is used to determine the forecast of peak internal demand and adjusting for diversity.

The demand forecast model is a series of algorithms for allocating the monthly net internal energy to hourly demand. The inputs into forecasting hourly demand are internal energy, weather, 24-hour load profiles and calendar information.

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, along with the stages of the development of the commercial and residential Statistically Adjusted End-Use models. Page 10 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 sequential steps for the peak demand and internal energy requirements forecasting. Displays of model equations, including the results of various statistical tests, along with data sets, are provided in the Appendix. Customer sensitive information will be provided as Chapter 2-Confidential Appendix, Customer Sensitive Information, and is provided in the Confidential Supplement.

C. FORECAST METHODOLOGY FOR INTERNAL ENERGY REQUIREMENTS (807 KAR 5:058 Sec. 5.2.and Sec. 7.7.b, c. and e.)

C.1. General

This section provides a detailed description of the short-term and long-term models employed in producing the forecasts of KPCo's energy consumption, by customer class. For the purposes of the load forecast, the short term is defined as the first two years, and the long term as the third forecast year and beyond.

Conceptually, the difference between short and long term energy consumption relates to changes in the stock of electricity-using equipment, rather than the passage of time. The short term covers the period during which changes are minimal, and the long term covers the period during which changes can be significant. In the short term, electric energy consumption is considered to be a function of an essentially fixed stock of equipment. For residential and commercial customers, the most significant factor influencing 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 models recognize these relationships and use weather and recent load growth trends as the primary variables in forecasting monthly energy sales.

Over time, demographic and economic factors such as population, employment, income, and technology determine the nature of the stock of electricity-using equipment, both in size and composition. Long-term forecasting models recognize the importance of these variables and include most of them in the formulation of 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, which are only included in long-term forecasts. This approach makes sense because although consumers may suffer sticker shock from energy price fluctuations, there is little they can do to impact them in the short-term. They already own a refrigerator, furnace or industrial equipment that may not be the most energy-efficient model available. 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 forecasts relied on autoregressive integrated moving average (ARIMA) models.

The estimation period for the short-term models was January 1998 through October 2008.

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

Short-term industrial energy sales are forecast separately for 10 large industrial customers in Kentucky and for the remainder of industrial energy customers segregated into manufacturing and mining load. These 12 short-term industrial energy sales models relate energy sales to lagged energy sales, lagged error terms and binary variables. The industrial models are estimated using ARIMA models. The short-term industrial energy sales forecast is a sum of the forecasts for the 10 large industrial customers and the forecasts for the remainder of the manufacturing and mining customers.

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 are 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 30 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 KPCo 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.

There are several techniques, including the use of lagged price or a moving average of price that can be used to introduce the concept of lagged response to price change into an econometric model. Each of these techniques incorporates price information from previous periods to estimate demand in the current period.

The general estimation period for the long-term load forecasting models was 1984-2008. The long-term energy sales forecast is developed by blending the last half of the second year of the short-term forecast with the long-term forecast. The energy sales forecast is developed by making a billed/unbilled adjustment to derive billed and accrued values, which are consistent with monthly generation.

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 "2008 Annual Energy Outlook". The estimation interval for the natural gas price model, which is an annual model, was 1973-2007.

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 "2008 Annual Energy Outlook." The estimation period for the model was 1975-2006.

C.3.b. Residential Energy Sales (807 KAR 5:058 Sec. 7.4.e.)

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 long-term residential customer forecasting model is linear and monthly. The model for the Company's service area is depicted as follows:

$$Customers = f(mortgagerate, employment, customers_{-1})$$

The mortgage interest rate provides a measure for household formation, while service area employment provides a measure of economic growth in the region, which will also affect customer growth. The lagged dependent variable captures the adjustment of customer growth to changes in the economy. There are also binary variables to capture monthly variations in customers, unusual data points and special occurrences.

The customer forecast is blended with the short-term residential customer forecast to produce a final forecast.

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

The residential usage model is estimated using a Statistically Adjusted End-Use Model (SAE), which was developed by Itron, a consulting firm with expertise in energy modeling. This model assumes that use will fall into one of three categories: heat, cool and other. The SAE model constructs variables to be used in an econometric equation like the following:

$$Use = f(Xheat, Xcool, Xother)$$

The Xheat variable is derived by multiplying a heating index variable by a heating use variable. The heating index incorporates information about heating equipment saturation; heating equipment efficiency standards and trends; and thermal integrity and size of homes. The heating use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xcool variable is derived by multiplying a cooling index variable by a cooling use variable. The cooling index incorporates information about cooling equipment saturation; cooling equipment efficiency standards and trends; and thermal integrity and size of homes. The cooling use variable is derived from information related to billing days, heating degree-days, household size, personal income, gas prices and electricity prices.

The Xother variable estimates the non-weather sensitive sales and is similar to the Xheat and Xcool variables. This variable incorporates information on appliance and equipment saturation levels; average number of days in the billing cycle each month; average household size; real personal income; gas prices and electricity prices.

The appliance saturations are based on historical trends from KPCo's residential customer survey. The saturation forecasts are based on DOE forecasts and analysis by Itron. The efficiency trends are based on U.S. Department of Energy (DOE) forecasts and Itron analysis. The thermal integrity and size of homes are for the East North Central Census Region and are based on DOE and Itron data.

The number of billing days is from internal data. Economic and demographic forecasts are from Moody's Economy.com and the electricity price forecast is developed internally.

The SAE model is estimated using a linear regression model. It is a monthly model for the period January 1990 through October 2008. This model incorporates the effects of the Energy Policy Act of 2005 (EPAct) and the Energy Independence and Security Act of 2007 (EISA) on the residential energy.

The long-term residential energy sales forecast is derived by multiplying the "blended" customer forecast by the usage forecast from the SAE model.

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 (807 KAR 5:058 Sec. 7.4.e.)

Long-term commercial energy sales are forecast using a SAE model. This model is similar to the residential SAE model. The functional model is as follows:

$$Energy = f(Xheat, Xcool, Xother)$$

As with the residential model, Xheat is determined by multiplying a heating index by a heat use variable. The variables incorporate information on heating degree-days, heating equipment saturation, heating equipment operating efficiencies, square footage, average number of days in a billing cycle, commercial output and electricity price.

The Xcool variable uses measures similar to the Xheat variable, except it uses information on cooling degree-days and cooling equipment, rather than those items related to heating load.

The Xother variable measures the non-weather sensitive commercial load. It uses non-weather sensitive equipment saturations and efficiencies, as well as billing days, commercial output and electricity price information.

The saturation, square footage and efficiencies are from the Itron base of DOE data and forecasts. The saturations and related items are from DOE's 2008 Annual Energy Outlook. Billing days and electricity prices are developed internally. The commercial output measure is real commercial gross regional product from Moody's Economy.com. The equipment stock and square footage information are for the East North Central Census Region.

The SAE is a linear regression for the period January 1996 through October 2008. As with the residential SAE model, the effects EPAct and EISA are captured in this model.

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

Manufacturing energy sales are estimated using a quarterly model, which is depicted as follows:

$$Energy = f(gasprice, electricprice, metal\sin dex, petroleu\min dex)$$

The manufacturing forecasting model relates energy sales to real price of natural gas, real price of electricity, FRB production indexes for primary metals and petroleum, and binary variables. The prices are modeled using twelve-quarter moving averages. The independent variables are modeled 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

Mine Power energy sales are estimated using a quarterly model, which is depicted as follows:

$$Energy = f(electricprice, coalproduction)$$

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 and a 12-quarter moving average of 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 binary variables. 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 service area gross regional product, 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.

C.3.f. Blending Short and Long-Term Sales

Forecast values for 2009 are taken from the short-term process. Forecast values for 2010 are obtained by blending the results from the short-term and long-term models. The blending process combines the results of the short-term and long-term models by assigning weights to each result and systematically changing the weights so that by the end of 2010 the entire forecast is from the long-term models. This blending allows for a smooth transition between the two separate processes, minimizing the impact of any differences in the results.

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

Energy is lost in the transmission and distribution of the product. This loss of energy from the source of production to consumption at the premise is measured as the average ratio of all FERC revenue class energy sales measured at the premise meter to the net internal energy requirements metered at the source. In modeling, company loss study results are incorporated to apply losses to each revenue class.

D. FORECAST METHODOLOGY FOR SEASONAL PEAK INTERNAL DEMAND (807 KAR 5:058 Sec. 5.2. and Sec. 7.7.b and c.)

The demand forecast model is a series of algorithms for allocating the monthly blended FERC revenue class sales to hourly demand. The inputs into forecasting hourly demand are blended FERC revenue class sales, energy loss multipliers, weather, 24-hour load profiles and calendar information.

The weather profiles are developed from representative weather stations in the service area. Twelve monthly profiles of average daily temperature that best represent the cooling and heating degree-days of the specific geography are taken from the last 30 years of historical values. The consistency of these profiles ensures the appropriate diversity of the company loads.

The 24-hour load profiles are developed from historical hourly company or jurisdictional load and end-use or revenue class hourly load profiles. The load profiles were developed from segregating, indexing and averaging hourly profiles by season, day types (weekend, midweek and Monday/Friday) and average daily temperature ranges. The end-use and class profiles were obtained from Iron, Inc. Energy Forecasting load shape library and modeled to represent each company or jurisdiction service area.

In forecasting, the weather profiles and calendars dictate which profile to apply and the sales plus losses results dictate the volume of energy under the profile. In the end, the profiles are benchmarked to the aggregate energy and seasonal peaks through the adjustments to the hourly load duration curves of the annual 8,760 hourly values. These 8,760 hourly values per year are the forecast load of the individual companies of AEP that can be aggregated by hour to represent load across the spectrum from end-use or revenue classes to total AEP-PJM, AEP-SPP or total AEP system. Net internal energy requirements are the sum of these hourly values to a total company energy need basis. Company peak demand is the maximum of the hourly values from a stated period (month, season or year).

E. LOAD FORECAST RESULTS

E.1. Load Forecast After Filed DSM Adjustments (Base Forecast) (807 KAR 5:058 Sec. 7.1.c.-g., Sec. 7.3, Sec. 7.4.a-d, Sec.7.5.b.1.-2.)

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 2004-2008 and on a forecast basis for the years 2009-2023. The exhibit also shows annual growth rates for both the historical and forecast periods. Corresponding information for the AEP-East Zone is given on Exhibit 2-6.

Exhibits 2-7 and 2-8 show for KPCo and the AEP-East Zone, 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., 2009 and 2010, KPCo's disaggregated energy requirements on a monthly basis, along with monthly peak demands.

E.2. Load Forecast Before DSM Adjustments (807 KAR 5:058 Sec. 7.1.c-g., Sec. 7.2.g., Sec. 7.3. and Sec. 7.4.a.-d, Sec. 7.5.b.1 and Sec. 7.5.b.2. and Sec. 8.4.a.6.)

Exhibit 2-12 lists the filed DSM adjustments (discussed in Chapter 3) that were used in the base forecasts of internal energy requirements and seasonal peak internal demands for both the AEP-East Zone and KPCo. The resulting forecasts, which reflect the load prior to 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 (807 KAR 5:058 Sec. 7.4.d.)

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 and regulatory requirements 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 filed DSM installations are analyzed and projected separately, and appropriate adjustments are made to derive the base load forecast.

The use of the SAE models for the residential and commercial sectors has enabled the Company to capture the anticipated effects of EPAct and EISA. The SAE models reflect not only equipment efficiencies, but also factors related to the building stock. These models reflect the Energy Information Administration (EIA) assessment of efficiency trends as provided in the 2008 Annual Energy Outlook.

G. ENERGY-PRICE RELATIONSHIPS (807 KAR 5:058 Sec. 7.7.e.1.)

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 disaggregated 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 tied to the EIA's forecast of nominal electricity prices by sector, as were provided in the 2008 Annual Energy Outlook. Likewise, the forecast state level natural gas prices by sector are modeled using information in the EIA outlook.

H. FORECAST UNCERTAINTY AND RANGE OF FORECASTS (807 KAR 5:058 Sec. 7.7.d.)

Even though load forecasts are created individually for each of the operating companies in the AEP-East Zone, and aggregated to form the AEP–East Zone 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-East Zone load.

Among the ways to characterize forecast uncertainty are: (1) the establishment of confidence intervals with 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. KPCo continues to support both approaches. However, this report uses scenarios for capacity planning sensitivity analyses.

The first step in producing high- and low-case scenarios was the estimation of an aggregated "mini-model" of AEP–East Zone 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 load forecasts for all operating companies. The mini-model is intended to represent the full forecasting structure employed in producing the base-case forecast for the AEP-East Zone and, by association, for the Company. The dependent variable is total AEP-East Zone internal energy requirements, excluding sales to the two aluminum reduction plants in the AEP–East Zone service area. This aluminum load is a large and volatile component of total load, which is treated judgmentally, not analytically, in the load forecast. It is simply added back 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 service area gross regional product, AEP-East Zone service-area employment, the average real price of electricity to all AEP-East Zone customer classes, the average real price of natural gas in the seven states served by AEP-East Zone, and AEP-East Zone service-area heating and cooling degree-days. All variables are expressed in logarithms with the exception of gross regional product and degree-days. Acceptance of this particular specification was 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 base 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 reflected professional judgment. The low- and high-case growth rates in real service area gross regional product for the forecast period were 0.9% and 2.0% per year, respectively, compared to 1.5% for the base case. The low- and high-case growth rates for AEP-East Zone region total employment were 0.0% and 0.6% per year, respectively, compared to 0.3% per year for the base case. For the real price of natural gas, the low case assumed a growth rate of -0.2% per year, and the high case assumed a growth rate of 0.9% per year. These compare to a base-case growth rate of 0.5% for the average real gas price in the seven states served in the AEP–East Zone.

For AEP-East Zone, the low-case and high-case energy and peak demand forecasts for the last forecast year, 2023, represent deviations of about 9% below and 10% 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 summer peak internal demand for the forecast period were 0.7% and 1.6% per year, respectively, compared to 1.2% per year for the base case.

The low-case, base-case and high-case forecasts of summer and winter peak demands and total energy requirements (after filed DSM adjustments) for AEP-East Zone 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.

The corresponding range of load forecasts prior to DSM adjustments is shown in Exhibits 2-23 (for the AEP System) and 2-24 (for KPCo).

I. SIGNIFICANT CHANGES FROM PREVIOUS FORECAST (807 KAR 5:058 Sec. 6)

I.1. Energy Forecast

During the ten years since the last filing with Commission, the nation's, AEP service area's, and KPCo's service areas economies have all experienced significant changes and therefore the load forecasts for AEP and KPCo reflect a more modest outlook.

Exhibit 2-25 provides a tabular comparison of the 1999 and 2009 forecasts of total internal energy requirements (before DSM adjustments) for both KPCo and the AEP-East Zone. Exhibit 2-26 shows the comparison for KPCo in graphical form. As these exhibits indicate, KPCo's 2009 energy forecast is lower than the 1999 forecast in terms of magnitude (1,095 GWh, or 11.3%, lower for year 2016) and long-term average annual growth rate (1.2% vs. 1.6%).

For the AEP-East Zone, the 2009 forecast for year 2016 is 5.7% less than the 1999 forecast.

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 11.3% decrease in the forecast of total energy requirements. Specifically, the residential, commercial, industrial and other retail energy sales forecasts were decreased by 26.0%, 17.1%, 4.5%, and 7.5%, respectively, while the losses forecast was increased by 42.5%.

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 Moody's Economy.com), a re-evaluation of expected long-term trends in residential and commercial consumption patterns in light of what has been experienced historically, and a more explicit accounting for appliance efficiency and other end-use trends. The changed assumptions reflect the effect of updated information obtained or developed since the 1999 forecast, along with changing perceptions of the future.

For the industrial sector, the relatively slight decrease reflects more recent trends that have evolved over the last tens for 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 2009 forecasts of the winter peak internal demand (before DSM adjustments) for both KPCo and the AEP-East Zone. This exhibit indicates that for the winter of 2016/17, KPCo's 2009 peak demand forecast is 13.7% 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 AEP-East Zone, for the winter of 2016/17, the 2009 forecast is 4.7% lower than the 1999 forecast.

I.3. Forecasting Methodology (807 KAR 5:058 Sec. 7.7.f)

Opportunities to enhance forecasting methods are explored by KPCo on a continuing basis. In this regard, the Company changed how it models peak demand, short-term industrial energy sales and long-term residential and commercial energy. Peak demand is now estimated using hourly load shapes, weather response functions and average daily temperature. Short-term industrial energy sales are now modeled by disaggregating load into 12 models, i.e., 10 large customers, small manufacturing and small mine power load. The residential and commercial long-term energy are now forecast using the SAE models, which provides some end-use flavor to the model analysis.

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

J. ADDITIONAL LOAD INFORMATION (807 KAR 5:058 Sec. 7.1.a. and b., Sec. 7.2.a-f. and h., Sec. 7.5.a.1 and 2 and Sec. 7.7.g.)

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

Exhibit 2-28: KPCo, Average Annual Number of Customers by Class, 2004-2008.

Exhibit 2-29: KPCo, Annual Internal Load by Class (GWh), 2004-2008.

Exhibit 2-30: KPCo and AEP System, Recorded and Weather-Normalized Peak Internal Load (MW) and Energy Requirements (GWh), 2004-2008. In addition, Normalized Annual Internal Sales by Class (GWh), 2004-2008.

Exhibit 2-31: AEP System and KPCo, Profiles of Monthly Peak Internal Demands, 2003, 2008 (Actual), 2018 and 2023.

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 2018 and 2023. These patterns also reflect the expectation that KPCo will continue to experience its annual peak demand in the winter season, while AEP-East Zone's annual peak is expected to occur in the summer.

Currently, the Company does not have any customers with interruptible provisions in their contracts. However, the Company does have Tariff Sheets filed with the Commission that would allow for interruptible service. None of the Company's customers operate under these tariffs.

The Company plans to conduct its next residential customer survey in the fall of 2009. As in the past, this survey will provide information on appliance saturations, along with other useful information to better understand the residential load.

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 Moody's 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 1999-2008. The gap between actual and forecast residential energy sales generally widened over the ten-year period. During this period residential customer growth dwindled to essentially no growth, with slight declines being experienced in 2007 and 2008. Another factor affecting sales is the impact of more stringent efficiency standards being mandated by Congress. Both of these factors will continue to have major influences on residential energy sales over the forecast period.

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 1999-2008. The exhibit also compares the calculated weather-normalized demands with the forecast values, thus indicating the extent to which weather affected actual demands.

There have been many changes in the local service over the 10 years since the 1999 forecast was filed. For, example the growth in residential customers has diminished greatly, there have been two major pieces of energy legislation enacted (i.e., EPAct and EISA), and commercial growth has slowed. Items, such as these, have contributed to a diminished outlook for peak demand growth. In addition, recent trends in normalized demand growth are evaluated when developing the forecast.

L.3. Other Scenario Analyses

Since the 1999 forecast filing there have been a number of emission requirements established. For NOx emissions, the Company has installed over-fire air on Big Sandy Unit 1 in 2002 and selective catalytic reduction on Unit 2 in 2003 to further reduce NOx emissions. The results of these projects are reflected in the Company's prices, which will have an impact on load forecasts.

L.4. Forecast Updates (807 KAR 5:058 Sec. 7.6.)

Each year the Company provides updates to the load forecast in response to requests related to Administrative Case 387.

L.5. 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.**

   The landscape of the power markets have changed dramatically since 1999. The push for retail competition has ebbed. Since that time AEP has become a member of PJM, which provides an additional market for energy and demand. However, AEP's membership in PJM has little impact on Kentucky Power's load forecast. Furthermore, the Company has long-term contracts with the only wholesale customers in its service area.

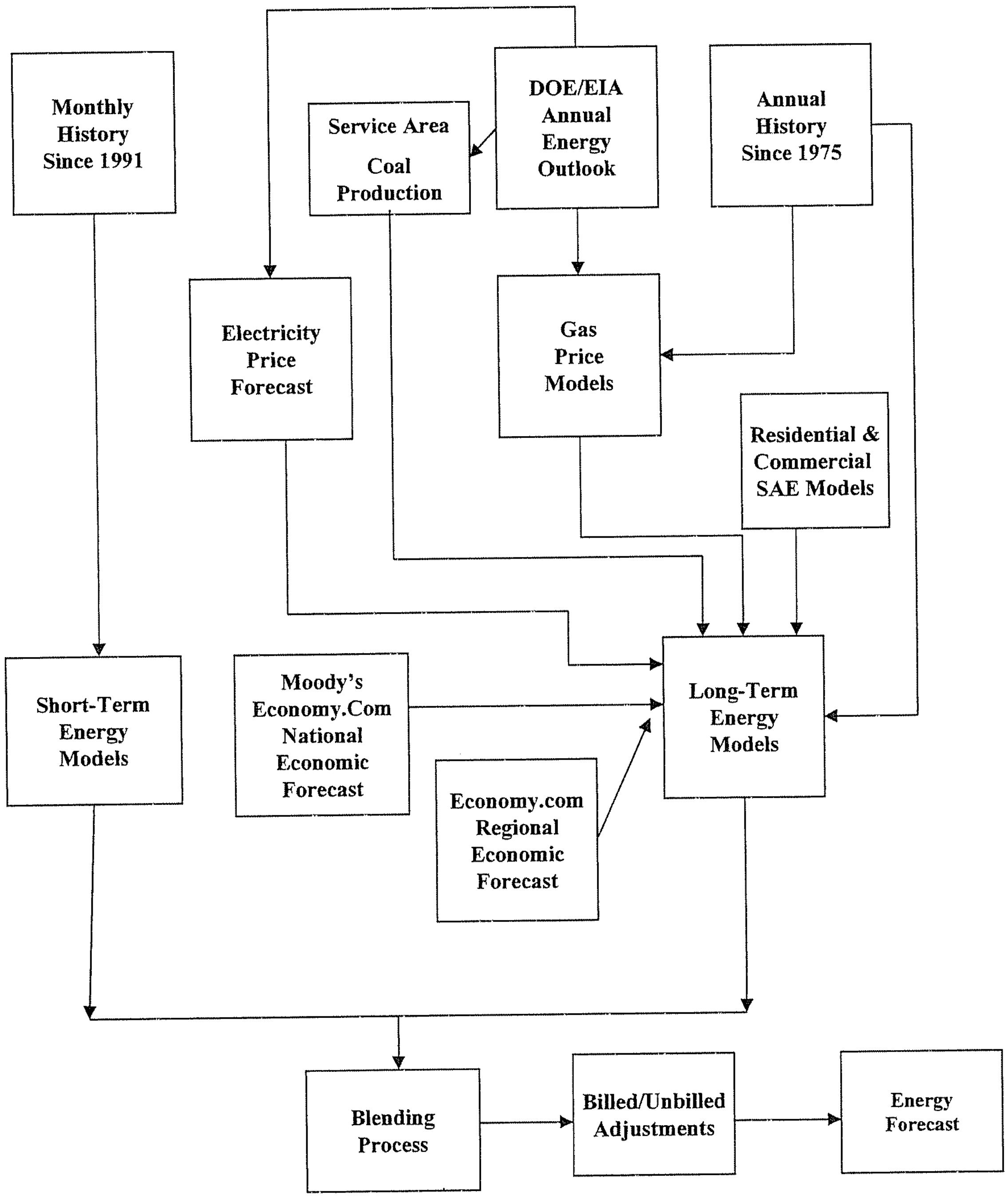
5. **Kentucky Power should attempt, either in its forecasts or in its uncertainty analysis, to incorporate the impacts of potential environmental costs such as those associated with potential NOx reductions imposed on sources in the Eastern United States.**

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

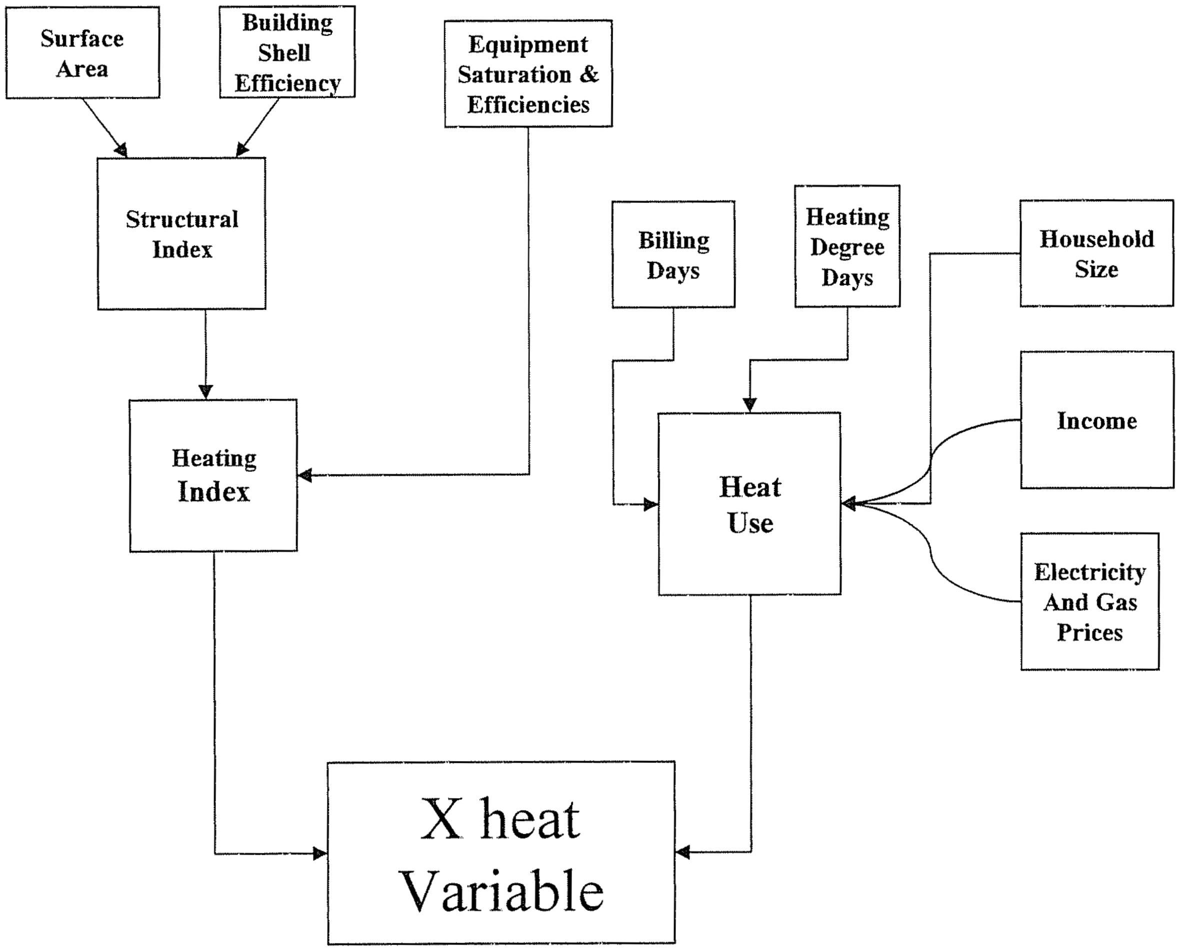
M. CHAPTER 2 EXHIBITS

The exhibits related to Chapter 2 are attached.

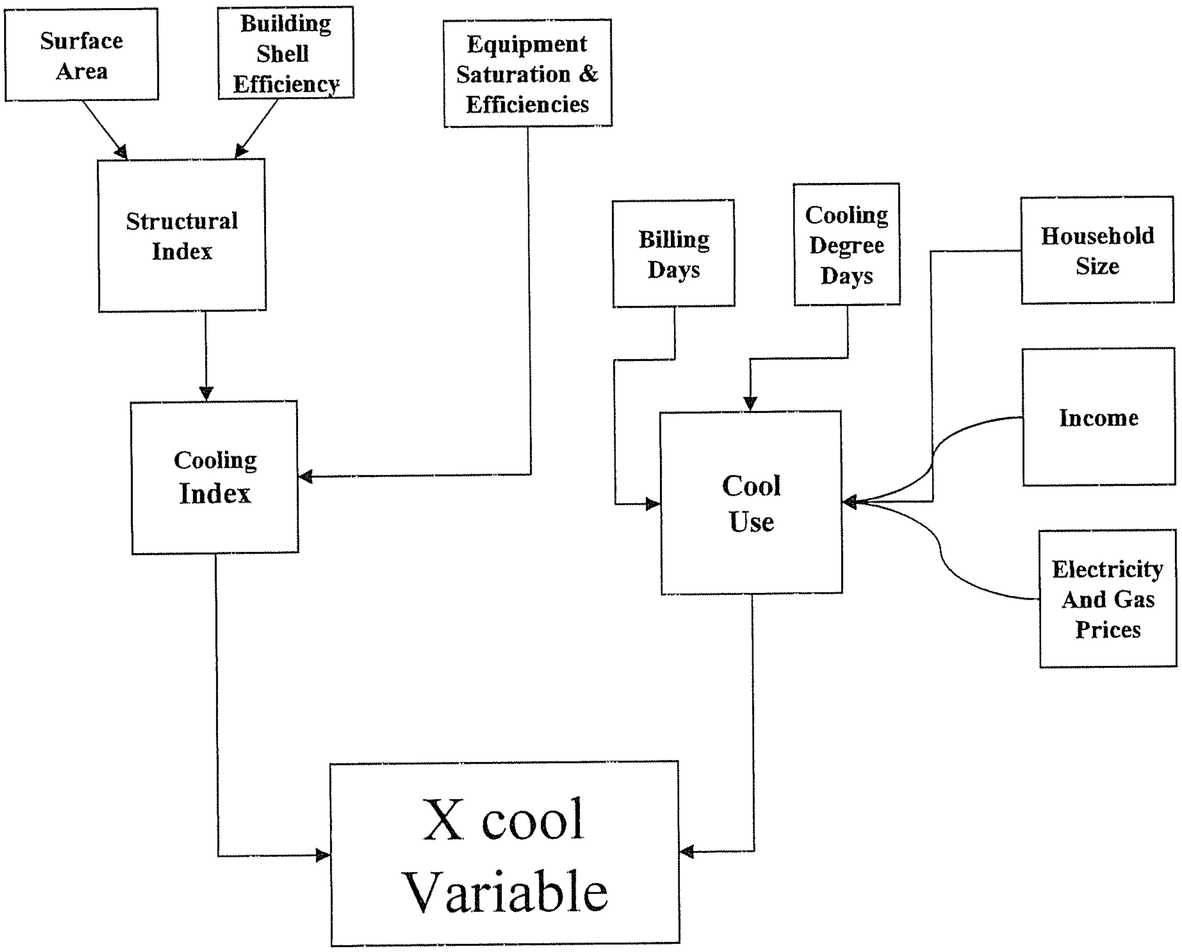
Kentucky Power Company
Internal Energy Requirements Forecasting Method



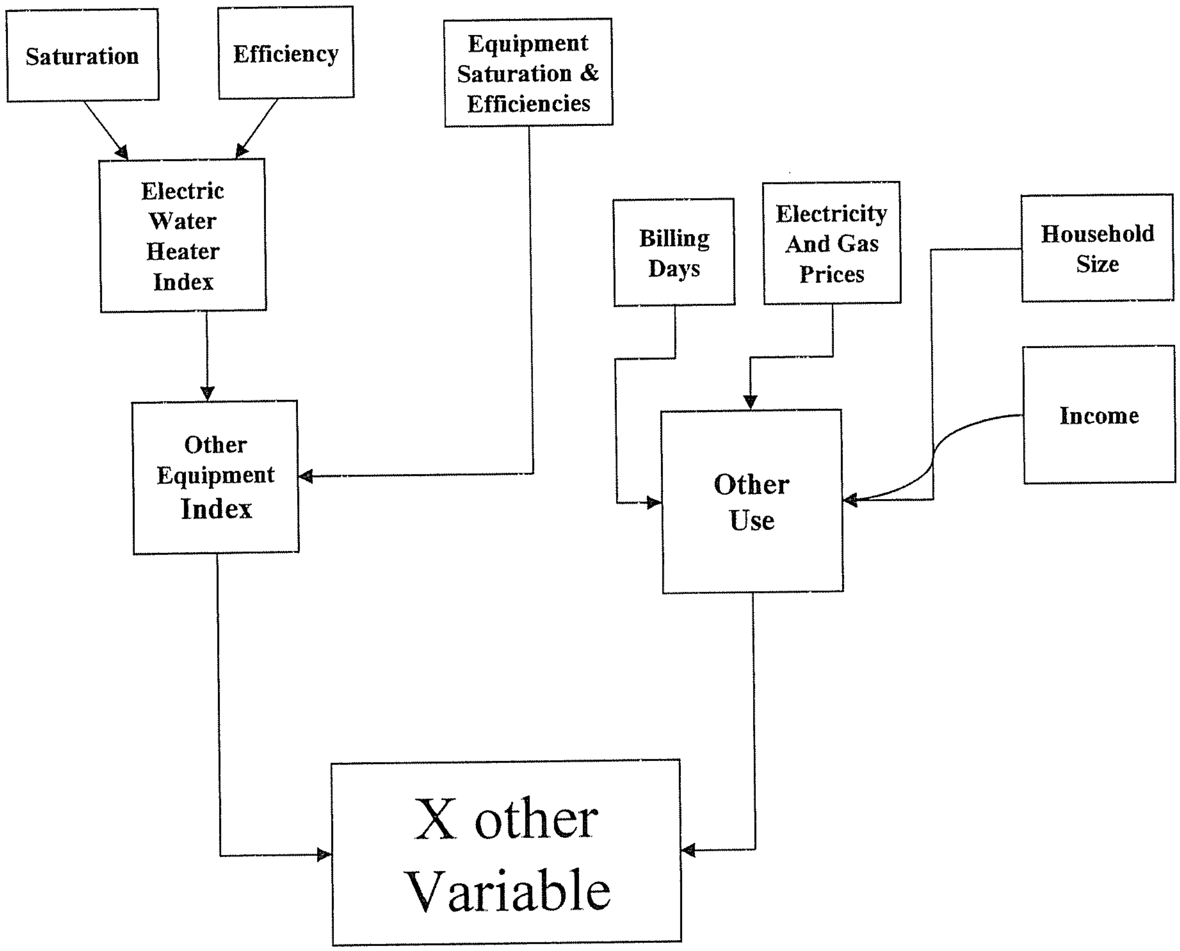
Kentucky Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X heat Variable



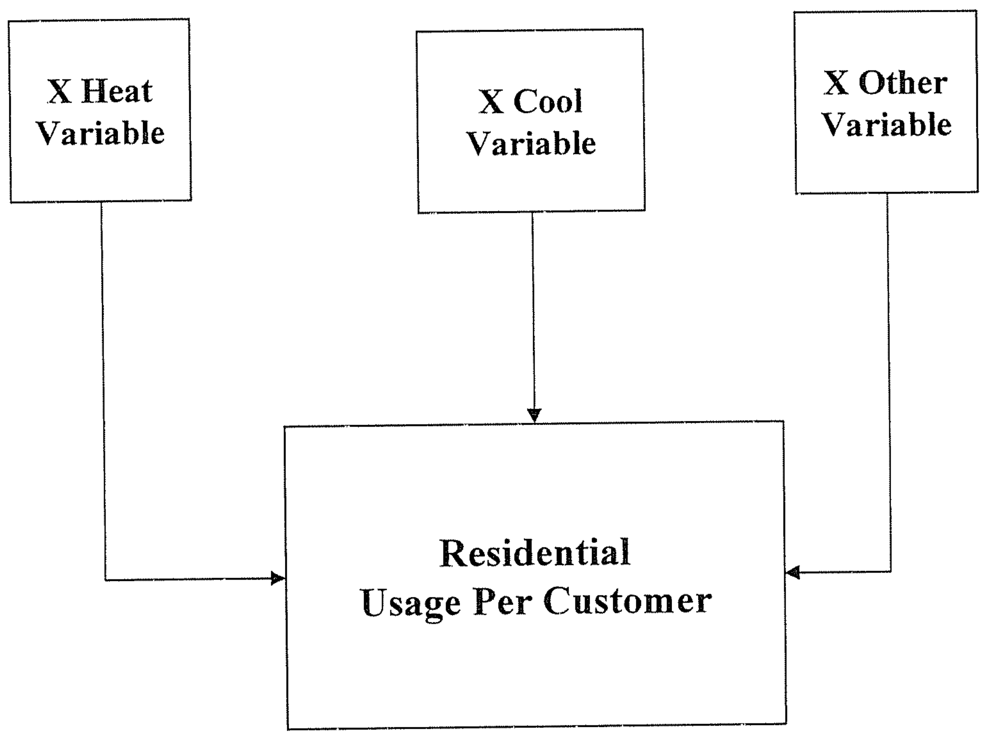
Kentucky Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X cool Variable



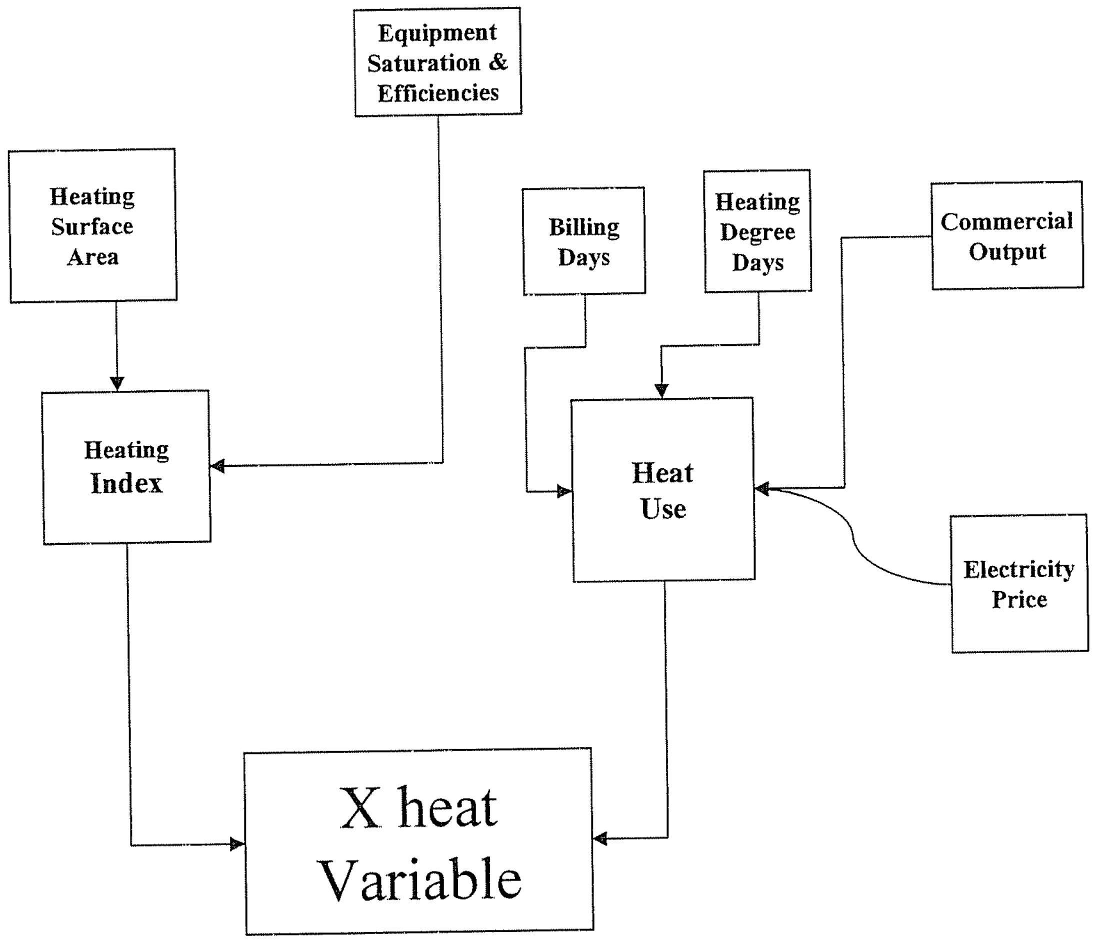
Kentucky Power Company
Residential Statistically Adjusted End-Use Model (SAE)
X other Variable



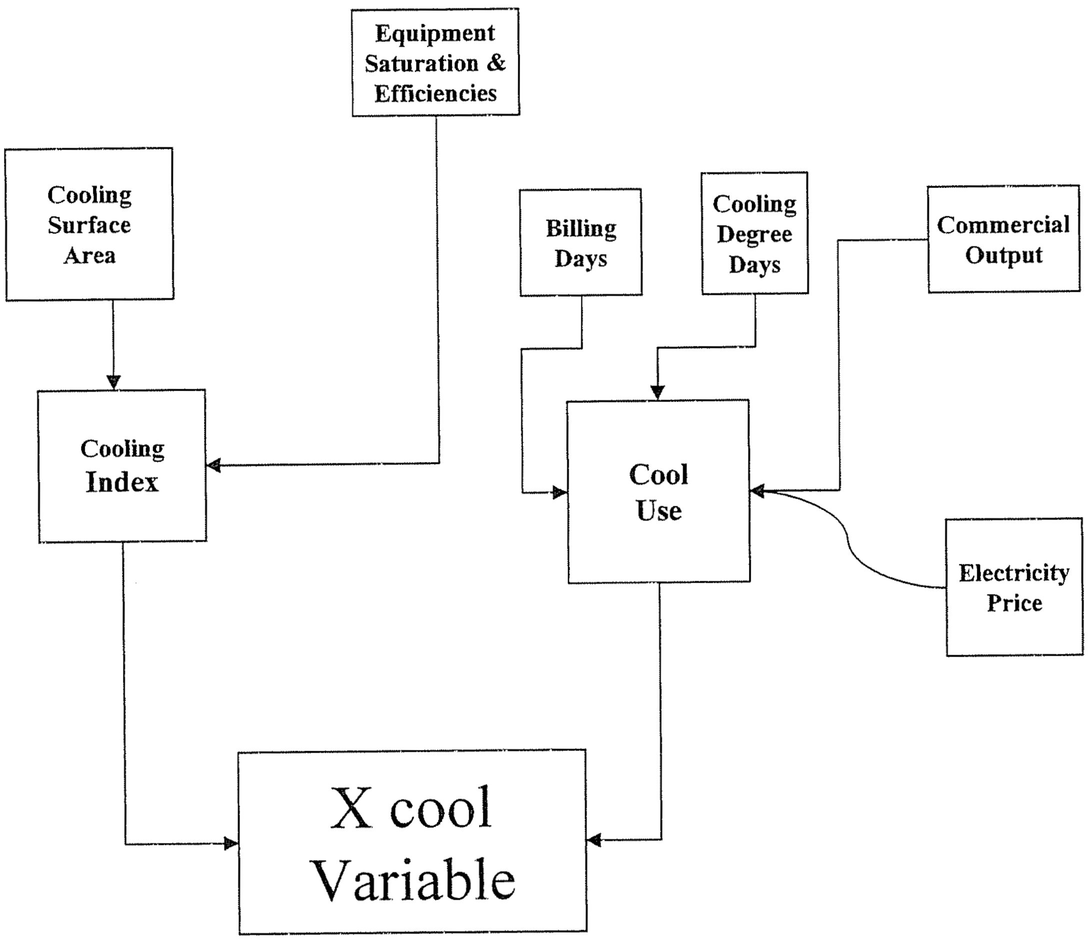
Kentucky Power Company
Residential Statistically Adjusted End-Use Model (SAE)



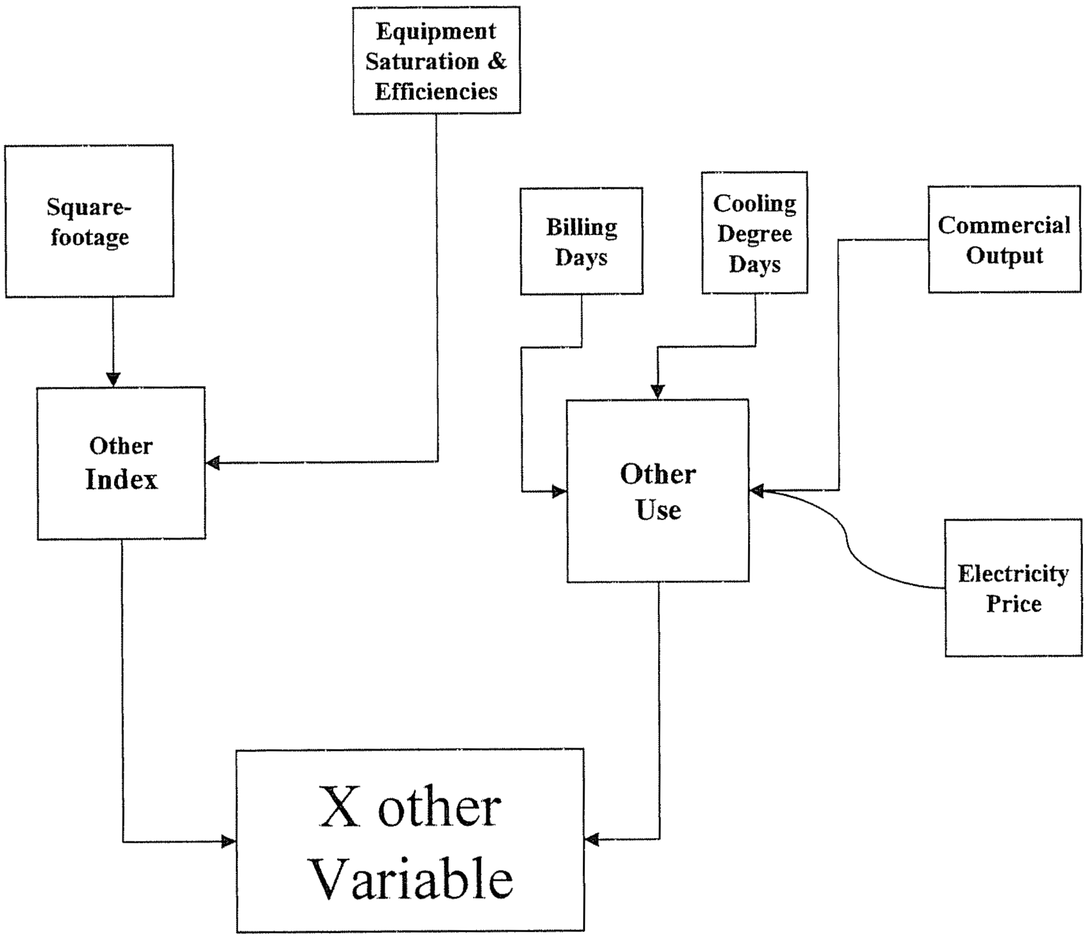
Kentucky Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X heat Variable



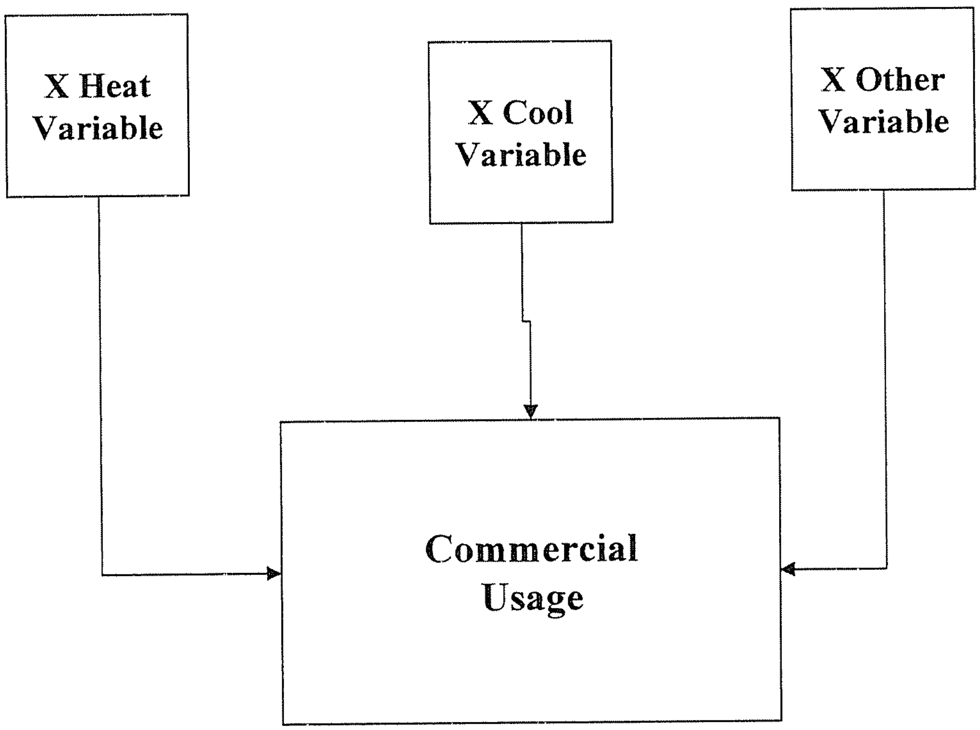
Kentucky Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X cool Variable



Kentucky Power Company
Commercial Statistically Adjusted End-Use Model (SAE)
X other Variable



Kentucky Power Company
Commercial Statistically Adjusted End-Use Model (SAE)

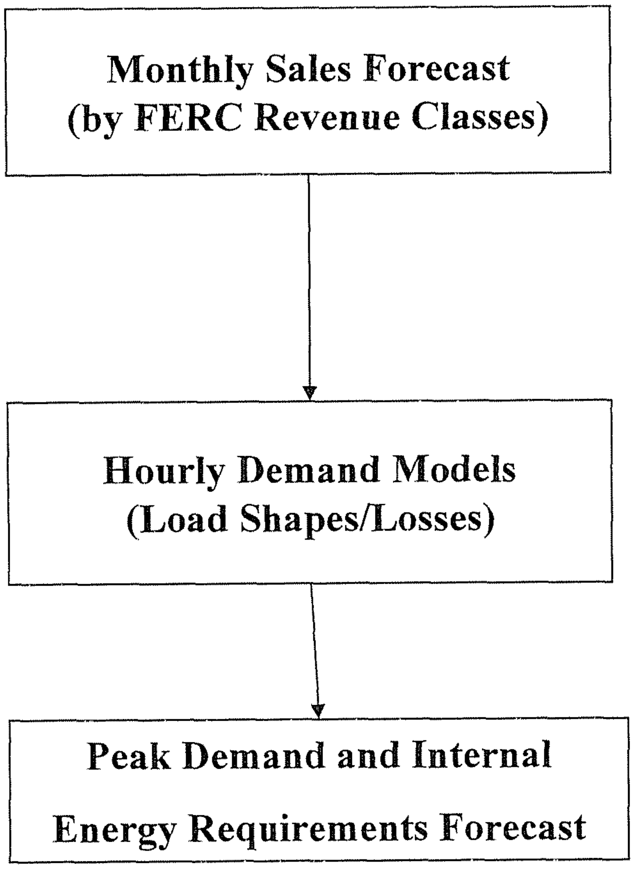


KENTUCKY POWER COMPANY
VARIABLES EMPLOYED IN FORECAST MODELS OF ENERGY SALES

Variable	Residential Customers		Residential Energy Sales		Commercial Customers	Commercial 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	Short Term	Long Term	Short Term	Long Term
Binary	X	X	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				
Residential Appliance Saturations				X									
Service Area Personal Income				X									
Service Area Population				X									
Residential Customers													
Service Area Employment		X											
Mortgage Interest Rate		X											
Heating Degree-Days			X	X		X	X					X	X
Cooling Degree-Days			X	X		X						X	X
Gross Regional Product							X						X
FRB Industrial Production Index									X				
Commercial Employment													X
Coal Production											X		

Exhibit 2-2

Kentucky Power Company Peak Demand and Internal Energy Requirements Forecast Process – Sequential Steps



Kentucky Power Company
Values of Variables Employed in the Long-Term Forecasts of
Residential and Commercial Energy Sales
1990, 2008 and 2023

	Actual		Forecast	Average Annual Growth Rate - %	
	1990	2008	Base 2023	1990-2008	2008-2023
Residential Energy Sales					
1. Service Area Employment	128,637	148,451	149,777	0.8	0.1
Residential Customers	131,085	144,087	144,977	0.5	0.0
1. Cooling Degree Days - Huntington, West Virginia	1,157	1,022	1,173	-0.7	0.9
2. Heating Degree Days - Huntington, West Virginia	2,127	2,433	2,512	0.7	0.2
3. Service Area Population	440,740	434,190	423,872	-0.1	-0.2
4. Service Area Real Personal Income ($ 1982-84 Million)	4,183	5,181	6,692	1.2	1.7
5. Real Residential Electricity Price Index (1982-4 cents per kWh)	4.19	3.22	3.46	-1.5	0.5
6. Real Kentucky Residential Gas Price Index (1982-84 $/MBtu)	3.81	6.41	5.95	2.9	-0.5
Residential Energy Sales (GWH)	1,718	2,481	2,460	1.4	-0.1
Commercial Energy Sales					
1. Service Area Commercial Regional Output (Index 2001=100)	69	117	140	2.0	1.2
2. Real Commercial Electricity Price (1982-84 cents per kWh)	4.47	3.29	3.31	-1.2	0.0
Commercial Energy Sales (GWH)	920	1,429	1,721	1.7	1.2

Exhibit 2-3

Kentucky Power Company
Values of Variables Employed in the Long-Term Forecasts for
<u>Manufacturing and Mine Power Energy Sales</u>
1990, 2008 and 2023

	Actual		Forecast	Average Annual Growth Rate-%	
	1990	2008	Base 2023	1990-2008	2008-2023
Manufacturing Energy Sales					
1. FRB Industrial Production Index for Petroleum (2002=100)	86.9	110.8	148.0	0.9	2.0
2. FRB Industrial Production Index for Primary Metals (2002=100)	96.7	111.4	147.2	0.5	1.9
3. Real Manufacturing Electricity Price (1982 cents per kWh)	2.59	2.37	2.23	-0.3	-0.4
4. Real Kentucky Manufacturing Gas Price (1982 $ per MCF)	3.10	6.00	4.98	2.6	-1.2
Manufacturing Energy Sales (GWH)	1,841	2,262	2,850	0.8	1.6
Mine Power Energy Sales					
1. Service Area Coal Production (Million Tons)	425.1	328.4	346.3	-1.0	0.4
2. Real Mining Electricity Price (1982 cents per kWh)	3.87	2.99	2.82	-1.0	-0.4
Mine Power Energy Sales (GWH)	1,042	1,059	1,084	0.1	0.2

Exhibit 2-4

Kentucky Power Company
Annual Internal Energy Requirements and Growth Rates
2004-2023

After Filed 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												
2004	2,411	--	1,373	--	3,181	--	106	--	718	--	7,790	--
2005	2,534	5.1	1,423	3.6	3,343	5.1	108	1.7	665	-7.4	8,072	3.6
2006	2,409	-4.9	1,392	-2.1	3,311	-0.9	107	-0.6	489	-26.5	7,709	-4.5
2007	2,485	3.1	1,446	3.8	3,174	-4.1	110	2.9	593	21.3	7,808	1.3
2008	2,481	-0.1	1,429	-1.2	3,322	4.7	110	0.0	565	-4.6	7,907	1.3
Forecast												
2009	2,492	0.4	1,447	1.3	3,259	-1.9	111	0.9	653	15.5	7,963	0.7
2010	2,466	-1.1	1,459	0.9	3,429	5.2	114	2.2	676	3.6	8,144	2.3
2011	2,449	-0.7	1,481	1.5	3,544	3.3	116	2.3	697	3.0	8,286	1.7
2012	2,438	-0.4	1,501	1.4	3,585	1.2	118	1.3	712	2.2	8,354	0.8
2013	2,439	0.0	1,526	1.6	3,626	1.2	119	1.1	706	-0.8	8,417	0.7
2014	2,431	-0.3	1,548	1.4	3,660	0.9	120	1.0	713	1.0	8,472	0.7
2015	2,427	-0.1	1,569	1.4	3,692	0.9	121	0.9	719	0.9	8,530	0.7
2016	2,426	0.0	1,591	1.4	3,725	0.9	123	1.1	728	1.2	8,593	0.7
2017	2,427	0.0	1,612	1.3	3,757	0.9	124	1.1	731	0.3	8,651	0.7
2018	2,429	0.1	1,631	1.2	3,789	0.9	125	1.0	733	0.4	8,707	0.7
2019	2,433	0.1	1,649	1.1	3,819	0.8	126	1.0	736	0.3	8,762	0.6
2020	2,435	0.1	1,665	1.0	3,846	0.7	128	1.0	743	1.0	8,816	0.6
2021	2,444	0.4	1,685	1.2	3,874	0.7	129	1.0	743	0.1	8,874	0.7
2022	2,450	0.3	1,702	1.0	3,903	0.8	130	1.0	754	1.5	8,940	0.7
2023	2,460	0.4	1,721	1.1	3,934	0.8	131	1.0	761	0.9	9,007	0.7
Average Annual Growth Rates:												
2004-2008		0.7		1.0		1.1		1.0		-5.8		0.4
2009-2023		-0.1		1.2		1.4		1.2		1.1		0.9

Exhibit 2-5

AEP-East Zone
Annual Internal Energy Requirements and Growth Rates
2004-2023

After Filed 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												
2004	34,921	--	26,966	--	40,986	--	6,696	--	7,063	--	116,633	--
2005	37,067	6.1	28,201	4.6	41,968	2.4	5,914	-11.7	7,531	6.6	120,682	3.5
2006	35,662	-3.8	28,056	-0.5	42,663	1.7	7,568	28.0	7,938	5.4	121,887	1.0
2007	37,586	5.4	29,649	5.7	46,358	8.7	9,238	22.1	7,691	-3.1	130,522	7.1
2008	37,321	-0.7	29,194	-1.5	47,238	1.9	9,694	4.9	8,000	4.0	131,446	0.7
Forecast												
2009	37,165	-0.4	29,171	-0.1	39,638	-16.1	7,718	-20.4	9,838	23.0	123,530	-6.0
2010	37,340	0.5	29,519	1.2	38,158	-3.7	7,415	-3.9	9,683	-1.6	122,116	-1.1
2011	37,412	0.2	30,056	1.8	47,219	23.7	7,659	3.3	9,751	0.7	132,096	8.2
2012	37,379	-0.1	30,448	1.3	47,743	1.1	7,855	2.6	10,177	4.4	133,603	1.1
2013	37,613	0.6	31,006	1.8	48,166	0.9	7,944	1.1	9,994	-1.8	134,724	0.8
2014	37,641	0.1	31,471	1.5	48,352	0.4	8,020	1.0	10,173	1.8	135,657	0.7
2015	37,760	0.3	31,975	1.6	48,512	0.3	8,096	1.0	10,264	0.9	136,608	0.7
2016	37,899	0.4	32,456	1.5	48,681	0.3	8,171	0.9	10,414	1.5	137,621	0.7
2017	38,066	0.4	32,919	1.4	48,856	0.4	8,251	1.0	10,395	-0.2	138,487	0.6
2018	38,216	0.4	33,317	1.2	48,979	0.3	8,328	0.9	10,477	0.8	139,317	0.6
2019	38,398	0.5	33,695	1.1	49,089	0.2	8,405	0.9	10,520	0.4	140,107	0.6
2020	38,549	0.4	34,021	1.0	49,176	0.2	8,483	0.9	10,687	1.6	140,917	0.6
2021	38,894	0.9	34,481	1.4	49,372	0.4	8,567	1.0	10,523	-1.5	141,837	0.7
2022	39,093	0.5	34,809	1.0	49,549	0.4	8,647	0.9	10,791	2.5	142,889	0.7
2023	39,392	0.8	35,206	1.1	49,782	0.5	8,728	0.9	10,890	0.9	143,998	0.8
Average Annual Growth Rates:												
2004-2023		1.7		2.0		3.6		9.7		3.2		3.0
2009-2023		0.4		1.4		1.6		0.9		0.7		1.1

Exhibit 2-6

Kentucky Power Company
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
2004-2023

After Filed 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											
2004	08/30/04	1,228	--	01/24/05	1,685	--	1,615	--	7,790	--	55.1
2005	07/26/05	1,358	10.6	12/20/05	1,665	-1.2	1,685	4.3	8,072	3.6	54.7
2006	08/02/06	1,292	-4.9	02/06/07	1,675	0.6	1,531	-9.1	7,709	-4.5	57.5
2007	08/24/07	1,348	4.3	01/25/08	1,678	0.2	1,675	9.4	7,808	1.3	53.1
2008	06/09/08	1,249	-7.3	01/16/09	1,673	-0.3	1,678	0.2	7,907	1.3	53.8
Forecast											
2009		1,308	4.8		1,639	-2.0	1,614	-3.8	7,963	0.7	56.3
2010		1,338	2.3		1,668	1.7	1,639	1.5	8,144	2.3	56.7
2011		1,357	1.4		1,672	0.3	1,668	1.7	8,286	1.7	56.7
2012		1,364	0.5		1,689	1.0	1,672	0.3	8,354	0.8	57.0
2013		1,379	1.1		1,700	0.7	1,689	1.0	8,417	0.7	56.9
2014		1,389	0.8		1,711	0.6	1,700	0.7	8,472	0.7	56.9
2015		1,400	0.8		1,717	0.4	1,711	0.6	8,530	0.7	56.9
2016		1,408	0.6		1,728	0.6	1,717	0.4	8,593	0.7	57.1
2017		1,420	0.8		1,739	0.6	1,728	0.6	8,651	0.7	57.1
2018		1,431	0.8		1,750	0.6	1,739	0.6	8,707	0.7	57.2
2019		1,441	0.7		1,754	0.3	1,750	0.6	8,762	0.6	57.2
2020		1,448	0.5		1,771	1.0	1,754	0.3	8,816	0.6	57.4
2021		1,462	1.0		1,784	0.7	1,771	1.0	8,874	0.7	57.2
2022		1,474	0.8		1,791	0.4	1,784	0.7	8,940	0.7	57.2
2023		1,483	0.6		1,799	0.4	1,791	0.4	9,007	0.7	57.4
Average Annual Growth Rates:											
1997-2001			0.4			-0.2		1.0		0.4	
2002-2016			0.9			0.7		0.7		0.9	

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.

Exhibit 2-7

AEP-East Zone
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
2004-2023

After Filed 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											
2004	08/30/04	19,049	--	01/18/05	19,796	--	19,615	--	116,633	--	67.9
2005	07/26/05	20,770	9.0	12/20/05	19,604	-1.0	20,770	5.9	120,681	3.5	66.3
2006	08/02/06	21,806	5.0	02/06/07	21,702	10.7	21,898	5.4	121,877	1.0	63.5
2007	08/08/07	22,413	2.8	01/25/08	21,977	1.3	22,413	2.4	130,522	7.1	66.3
2008	06/09/08	21,608	-3.6	01/16/09	22,269	1.3	21,977	-1.9	131,446	0.7	68.3
Forecast											
2009		21,077	-2.5		20,338	-8.7	21,077	-4.1	123,530	-6.0	66.9
2010		21,160	0.4		21,726	6.8	21,160	0.4	122,116	-1.1	65.9
2011		22,368	5.7		21,864	0.6	22,368	5.7	132,096	8.2	67.4
2012		22,595	1.0		22,130	1.2	22,595	1.0	133,603	1.1	67.5
2013		22,876	1.2		22,297	0.8	22,876	1.2	134,724	0.8	67.2
2014		23,079	0.9		22,456	0.7	23,079	0.9	135,657	0.7	67.1
2015		23,276	0.9		22,550	0.4	23,276	0.9	136,608	0.7	67.0
2016		23,423	0.6		22,702	0.7	23,423	0.6	137,621	0.7	67.1
2017		23,651	1.0		22,840	0.6	23,651	1.0	138,487	0.6	66.8
2018		23,828	0.7		22,976	0.6	23,828	0.7	139,317	0.6	66.7
2019		23,999	0.7		23,038	0.3	23,999	0.7	140,107	0.6	66.6
2020		24,112	0.5		23,268	1.0	24,112	0.5	140,917	0.6	66.7
2021		24,358	1.0		23,441	0.7	24,358	1.0	141,837	0.7	66.5
2022		24,566	0.9		23,561	0.5	24,566	0.9	142,889	0.7	66.4
2023		24,768	0.8		23,674	0.5	24,768	0.8	143,998	0.8	66.4
Average Annual Growth Rates:											
2004-2008			3.2			3.0		2.9		3.0	
2009-2023			1.2			1.1		1.2		1.1	

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.

Exhibit 2-8

Exhibit 2-9
(Page 1of 2)

Kentucky Power Company
Annual Internal Load
2009-2018

After Filed DSM Adjustments

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Internal Energy (GWH)										
Residential	2,492	2,466	2,449	2,438	2,439	2,431	2,427	2,426	2,427	2,429
Commercial	1,447	1,459	1,481	1,501	1,526	1,548	1,569	1,591	1,612	1,631
Industrial	3,259	3,429	3,544	3,585	3,626	3,660	3,692	3,725	3,757	3,789
Total Other Ultimate	10	10	10	10	10	10	10	10	10	10
Total Ultimate Sales	7,209	7,364	7,483	7,535	7,602	7,649	7,699	7,753	7,806	7,859
Municipals	101	103	106	107	109	110	111	112	113	115
Total Sales-for-Resale	101	103	106	107	109	110	111	112	113	115
Total Internal Sales	7,310	7,468	7,589	7,642	7,711	7,759	7,810	7,865	7,920	7,974
Total Losses	653	676	697	712	706	713	719	728	731	733
Total Internal Energy	7,963	8,144	8,286	8,354	8,417	8,472	8,530	8,593	8,651	8,707
Internal Peak Demand (MW)										
Summer	1,308	1,338	1,357	1,364	1,379	1,389	1,400	1,408	1,420	1,431
Preceding Winter	1,639	1,668	1,672	1,689	1,700	1,711	1,717	1,728	1,739	1,750

Kentucky Power Company
Annual Internal Load
2019-2023

After Filed DSM Adjustments

	2019	2020	2021	2022	2023
Internal Energy (GWH)					
Residential	2,433	2,435	2,444	2,450	2,460
Commercial	1,649	1,665	1,685	1,702	1,721
Industrial	3,819	3,846	3,874	3,903	3,934
Total Other Ultimate	11	11	11	11	11
Total Ultimate Sales	7,911	7,956	8,013	8,066	8,125
Municipals	116	117	118	120	121
Total Sales-for-Resale	116	117	118	120	121
Total Internal Sales	8,027	8,073	8,131	8,186	8,246
Total Losses	736	743	743	754	761
Total Internal Energy	8,762	8,816	8,874	8,940	9,007
Internal Peak Demand (MW)					
Summer	1,441	1,448	1,462	1,474	1,483
Preceding Winter	1,754	1,771	1,784	1,791	1,799

Kentucky Power Company
Monthly Internal Load
2009

After Filed DSM Adjustments

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	335.2	263.3	231.1	161.1	135.8	167.5	205.3	204.5	159.1	140.3	192.6	296.4	2,492
Commercial	134.7	118.3	116.4	111.5	116.4	124.2	127.8	130.4	119.3	116.7	106.8	124.0	1,447
Industrial	272.8	264.6	278.5	274.6	282.9	271.4	259.0	278.3	252.8	279.6	273.8	271.1	3,259
Total Other Ultimate	1.1	0.8	0.9	0.8	0.8	0.6	0.8	0.8	0.7	1.0	1.0	1.1	10
Total Ultimate Sales	743.8	647.0	626.9	548.1	535.9	563.8	592.8	613.9	532.0	537.7	574.2	692.6	7,209
Municipals	9.6	9.9	9.1	8.1	7.5	7.6	8.3	8.6	8.3	7.6	7.8	8.7	101
Total Sales-for-Resale	9.6	9.9	9.1	8.1	7.5	7.6	8.3	8.6	8.3	7.6	7.8	8.7	101
Total Internal Sales	753.4	656.9	636.0	556.2	543.4	571.5	601.1	622.5	540.2	545.2	581.9	701.3	7,310
Total Losses	60.0	54.4	52.6	46.1	45.1	47.3	49.7	51.3	44.3	44.7	73.4	83.9	653
Total Internal Energy	813.4	711.3	688.6	602.2	588.5	618.8	650.8	673.8	584.5	590.0	655.4	785.1	7,963
Internal Peak Demand (MW)	1,519	1,614	1,295	1,130	1,060	1,193	1,220	1,308	1,141	1,038	1,310	1,517	1,614

Exhibit 2-10

Kentucky Power Company
Monthly Internal Load
2010

After Filed DSM Adjustments

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Internal Energy (GWH)													
Residential	334.7	264.1	232.3	156.8	130.9	159.0	206.1	200.1	158.6	132.6	188.5	302.3	2,466
Commercial	135.4	120.2	119.1	113.6	118.2	120.7	129.9	129.7	121.8	114.6	106.4	129.2	1,459
Industrial	281.3	273.4	292.8	287.8	295.2	278.2	269.7	288.8	266.1	298.2	295.6	301.7	3,429
Total Other Ultimate	1.1	0.8	0.9	0.8	0.8	0.6	0.8	0.8	0.7	1.0	1.0	1.1	10
Total Ultimate Sales	752.4	658.5	645.1	559.0	545.1	558.5	606.6	619.4	547.2	546.4	591.5	734.3	7,364
Municipals	9.7	10.0	9.2	8.3	7.7	7.8	8.6	8.8	8.5	7.8	8.0	9.0	103
Total Sales-for-Resale	9.7	10.0	9.2	8.3	7.7	7.8	8.6	8.8	8.5	7.8	8.0	9.0	103
Total Internal Sales	762.2	668.4	654.3	567.3	552.8	566.4	615.2	628.2	555.7	554.3	599.5	743.3	7,468
Total Losses	62.7	55.1	53.9	46.8	48.2	64.9	50.6	65.8	45.7	50.4	71.0	61.3	676
Total Internal Energy	824.9	723.6	708.2	614.1	601.0	631.2	665.8	694.1	601.4	604.6	670.5	804.5	8,144
Internal Peak Demand (MW)	1,543	1,639	1,349	1,150	1,075	1,214	1,248	1,338	1,169	1,063	1,338	1,547	1,639

Exhibit 2-11

Exhibit 2-12

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

	Energy Requirements Impacts GWH						Peak Demand Impacts MW	
Year	Residential	Commercial	Industrial	Other Retail	Losses	Total	Summer	Winter Following
2009	56	54	59	0	14	183	54	81
2010	143	140	165	1	36	486	137	91
2011	264	258	315	2	67	907	251	169
2012	266	265	316	2	68	917	254	172
2013	267	270	317	2	69	925	255	178
2014	268	275	317	2	70	932	258	179
2015	269	279	317	2	70	937	258	175
2016	268	282	317	2	70	940	254	175
2017	268	285	317	2	70	942	255	178
2018	267	286	317	2	71	944	256	179
2019	266	288	317	2	71	944	258	179
2020	265	289	316	2	71	944	258	173
2021	265	290	316	2	71	943	256	174
2022	264	290	316	2	71	943	254	173
2023	264	291	316	2	71	943	255	175

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	Other Retail	Losses	Total	Summer	Winter Following
2009	1	0	0	0	0	1	0	1
2010	2	0	0	0	0	3	0	2
2011	4	0	0	0	0	4	0	2
2012	4	0	0	0	0	4	0	2
2013	4	0	0	0	0	4	0	2
2014	4	0	0	0	0	4	0	2
2015	3	0	0	0	0	3	0	2
2016	3	0	0	0	0	3	0	2
2017	3	0	0	0	0	3	0	2
2018	3	0	0	0	0	3	0	2
2019	3	0	0	0	0	3	0	1
2020	3	0	0	0	0	3	0	1
2021	3	0	0	0	0	3	0	2
2022	3	0	0	0	0	3	0	2
2023	3	0	0	0	0	3	0	2

Kentucky Power Company
Annual Internal Energy Requirements and Growth Rates
2004-2023

Prior to 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												
2004	2,411	--	1,373	--	3,181	--	106	--	718	--	7,790	--
2005	2,534	5.1	1,423	3.6	3,343	5.1	108	1.7	665	-7.4	8,072	3.6
2006	2,409	-4.9	1,392	-2.1	3,311	-0.9	107	-0.6	489	-26.5	7,709	-4.5
2007	2,485	3.1	1,446	3.8	3,174	-4.1	110	2.9	593	21.3	7,808	1.3
2008	2,481	-0.1	1,429	-1.2	3,322	4.7	110	0.0	565	-4.6	7,907	1.3
Forecast												
2009	2,493	0.5	1,447	1.3	3,259	-1.9	111	0.9	653	15.5	7,964	0.7
2010	2,469	-1.0	1,459	0.9	3,429	5.2	114	2.2	676	3.6	8,146	2.3
2011	2,453	-0.6	1,481	1.5	3,544	3.3	116	2.3	697	3.0	8,290	1.8
2012	2,442	-0.4	1,501	1.4	3,585	1.2	118	1.3	712	2.2	8,358	0.8
2013	2,443	0.0	1,526	1.6	3,626	1.2	119	1.1	706	-0.8	8,420	0.7
2014	2,434	-0.3	1,548	1.4	3,660	0.9	120	1.0	713	1.0	8,475	0.7
2015	2,431	-0.2	1,569	1.4	3,692	0.9	121	0.9	719	0.9	8,533	0.7
2016	2,430	0.0	1,591	1.4	3,725	0.9	123	1.1	728	1.2	8,596	0.7
2017	2,430	0.0	1,612	1.3	3,757	0.9	124	1.1	731	0.3	8,654	0.7
2018	2,432	0.1	1,631	1.2	3,789	0.9	125	1.0	733	0.4	8,710	0.7
2019	2,435	0.1	1,649	1.1	3,819	0.8	126	1.0	736	0.3	8,765	0.6
2020	2,438	0.1	1,665	1.0	3,846	0.7	128	1.0	743	0.9	8,819	0.6
2021	2,447	0.4	1,685	1.2	3,874	0.7	129	1.0	743	0.1	8,877	0.7
2022	2,453	0.3	1,702	1.0	3,903	0.8	130	1.0	755	1.5	8,943	0.7
2023	2,462	0.4	1,721	1.1	3,934	0.8	131	1.0	761	0.9	9,009	0.7
Average Annual Growth Rates:												
2004-2008		0.7		1.0		1.1		1.0		-5.8		0.4
2009-2023		-0.1		1.2		1.4		1.2		1.1		0.9

Exhibit 2-13

AEP-East Zone
Annual Internal Energy Requirements and Growth Rates
2004-2023

Prior to 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												
2004	34,921	--	26,966	--	40,986	--	6,696	--	7,063	--	116,633	--
2005	37,067	6.1	28,201	4.6	41,968	2.4	5,914	-11.7	7,531	6.6	120,682	3.5
2006	35,662	-3.8	28,056	-0.5	42,663	1.7	7,568	28.0	7,938	5.4	121,887	1.0
2007	37,586	5.4	29,649	5.7	46,358	8.7	9,238	22.1	7,691	-3.1	130,522	7.1
2008	37,321	-0.7	29,194	-1.5	47,238	1.9	9,694	4.9	8,000	4.0	131,446	0.7
Forecast												
2009	37,221	-0.3	29,225	0.1	39,697	-16.0	7,718	-20.4	9,851	23.2	123,712	-5.9
2010	37,483	0.7	29,660	1.5	38,323	-3.5	7,415	-3.9	9,719	-1.3	122,600	-0.9
2011	37,676	0.5	30,314	2.2	47,534	24.0	7,659	3.3	9,818	1.0	133,001	8.5
2012	37,645	-0.1	30,713	1.3	48,060	1.1	7,855	2.6	10,245	4.4	134,518	1.1
2013	37,881	0.6	31,277	1.8	48,483	0.9	7,944	1.1	10,063	-1.8	135,647	0.8
2014	37,910	0.1	31,746	1.5	48,669	0.4	8,020	1.0	10,243	1.8	136,587	0.7
2015	38,029	0.3	32,254	1.6	48,829	0.3	8,096	1.0	10,334	0.9	137,542	0.7
2016	38,167	0.4	32,738	1.5	48,998	0.3	8,171	0.9	10,485	1.5	138,559	0.7
2017	38,334	0.4	33,204	1.4	49,173	0.4	8,251	1.0	10,466	-0.2	139,428	0.6
2018	38,483	0.4	33,604	1.2	49,296	0.2	8,328	0.9	10,548	0.8	140,258	0.6
2019	38,664	0.5	33,983	1.1	49,406	0.2	8,405	0.9	10,590	0.4	141,048	0.6
2020	38,815	0.4	34,310	1.0	49,493	0.2	8,483	0.9	10,758	1.6	141,859	0.6
2021	39,158	0.9	34,771	1.3	49,688	0.4	8,567	1.0	10,594	-1.5	142,778	0.6
2022	39,358	0.5	35,099	0.9	49,865	0.4	8,647	0.9	10,861	2.5	143,830	0.7
2023	39,656	0.8	35,497	1.1	50,098	0.5	8,728	0.9	10,960	0.9	144,940	0.8
Average Annual Growth Rates:												
2004-2008		1.7		2.0		3.6		9.7		3.2		3.0
2009-2023		0.5		1.4		1.7		0.9		0.8		1.1

Kentucky Power Company
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
2004-2023

Prior to 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											
2004		1,228	--		1,685	--	1,615	--	7,790	--	55.1
2005		1,358	10.6		1,665	-1.2	1,685	4.3	8,072	3.6	54.7
2006		1,292	-4.9		1,675	0.6	1,531	-9.1	7,709	-4.5	57.5
2007		1,348	4.3		1,678	0.2	1,675	9.4	7,808	1.3	53.1
2008		1,249	-7.3		1,673	-0.3	1,678	0.2	7,907	1.3	53.8
Forecast											
2009		1,309	4.8		1,640	-2.0	1,614	-3.8	7,964	0.7	56.3
2010		1,338	2.3		1,669	1.8	1,640	1.6	8,146	2.3	56.7
2011		1,357	1.4		1,674	0.3	1,669	1.8	8,290	1.8	56.7
2012		1,364	0.5		1,691	1.0	1,674	0.3	8,358	0.8	57.0
2013		1,379	1.1		1,702	0.7	1,691	1.0	8,420	0.7	56.8
2014		1,390	0.8		1,713	0.6	1,702	0.7	8,475	0.7	56.8
2015		1,400	0.8		1,719	0.4	1,713	0.6	8,533	0.7	56.9
2016		1,408	0.6		1,730	0.6	1,719	0.4	8,596	0.7	57.1
2017		1,420	0.8		1,741	0.6	1,730	0.6	8,654	0.7	57.1
2018		1,431	0.8		1,751	0.6	1,741	0.6	8,710	0.7	57.1
2019		1,441	0.7		1,756	0.3	1,751	0.6	8,765	0.6	57.1
2020		1,448	0.5		1,773	1.0	1,756	0.3	8,819	0.6	57.3
2021		1,462	1.0		1,785	0.7	1,773	1.0	8,877	0.7	57.2
2022		1,474	0.8		1,793	0.4	1,785	0.7	8,943	0.7	57.2
2023		1,483	0.6		1,800	0.4	1,793	0.4	9,009	0.7	57.4
Average Annual Growth Rates:											
2004-2008			0.4			-0.2		1.0		0.4	
2009-2023			0.9			0.7		0.8		0.9	

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.

Exhibit 2-15

AEP-East Zone
Seasonal and Annual Peak Demands, Energy Requirements and Load Factor
2004-2023

Prior to 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											
2004		19,049	--		19,796	--	19,615	--	116,633	--	67.9
2005		20,770	9.0		19,604	-1.0	20,770	5.9	120,681	3.5	66.3
2006		21,806	5.0		21,702	10.7	21,898	5.4	121,877	1.0	63.5
2007		22,413	2.8		21,977	1.3	22,413	2.4	130,522	7.1	66.3
2008		21,608	-3.6		22,269	1.3	21,977	-1.9	131,446	0.7	68.3
Forecast											
2009		21,131	-2.2		20,419	-8.3	21,131	-3.8	123,713	-5.9	66.8
2010		21,297	0.8		21,818	6.9	21,241	0.5	122,601	-0.9	65.9
2011		22,619	6.2		22,033	1.0	22,459	5.7	133,003	8.5	67.6
2012		22,849	1.0		22,302	1.2	22,764	1.4	134,520	1.1	67.5
2013		23,131	1.2		22,475	0.8	23,048	1.2	135,649	0.8	67.2
2014		23,336	0.9		22,634	0.7	23,256	0.9	136,589	0.7	67.0
2015		23,534	0.8		22,725	0.4	23,455	0.9	137,544	0.7	66.9
2016		23,677	0.6		22,877	0.7	23,598	0.6	138,561	0.7	67.0
2017		23,906	1.0		23,017	0.6	23,826	1.0	139,430	0.6	66.8
2018		24,084	0.7		23,154	0.6	24,006	0.8	140,260	0.6	66.7
2019		24,257	0.7		23,216	0.3	24,178	0.7	141,051	0.6	66.6
2020		24,370	0.5		23,441	1.0	24,291	0.5	141,861	0.6	66.7
2021		24,614	1.0		23,614	0.7	24,531	1.0	142,780	0.6	66.4
2022		24,821	0.8		23,734	0.5	24,740	0.9	143,832	0.7	66.4
2023		25,023	0.8		23,849	0.5	24,941	0.8	144,942	0.8	66.3
Average Annual Growth Rates:											
2004-2008			3.2			3.0		2.9		3.0	
2009-2023			1.2			1.1		1.2		1.1	

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.

Exhibit 2-16

Kentucky Power Company

Annual Internal Load

2009-2018

Prior to DSM Adjustments

	2009	2010	2011	2012	2013	2014	2015	2016	2017	2018
Internal Energy (GWH)										
Residential	2,493	2,469	2,453	2,442	2,443	2,434	2,431	2,430	2,430	2,432
Commercial	1,447	1,459	1,481	1,501	1,526	1,548	1,569	1,591	1,612	1,631
Industrial	3,259	3,429	3,544	3,585	3,626	3,660	3,692	3,725	3,757	3,789
Total Other Ultimate	10	10	10	10	10	10	10	10	10	10
Total Ultimate Sales	7,210	7,367	7,487	7,538	7,606	7,652	7,703	7,756	7,810	7,862
Municipals	101	103	106	107	109	110	111	112	113	115
Total Sales-for-Resale	101	103	106	107	109	110	111	112	113	115
Total Internal Sales	7,311	7,470	7,593	7,646	7,714	7,762	7,813	7,868	7,923	7,977
Total Losses	653	676	697	712	706	713	719	728	731	733
Total Internal Energy	7,964	8,146	8,290	8,358	8,420	8,475	8,533	8,596	8,654	8,710
Internal Peak Demand (MW)										
Summer	1,309	1,338	1,357	1,364	1,379	1,390	1,400	1,408	1,420	1,431
Preceding Winter	1,640	1,669	1,674	1,691	1,702	1,713	1,719	1,730	1,741	1,751

Kentucky Power Company
Annual Internal Load
2019-2023

Prior to DSM Adjustments

	2019	2020	2021	2022	2023
Internal Energy (GWH)					
Residential	2,435	2,438	2,447	2,453	2,462
Commercial	1,649	1,665	1,685	1,702	1,721
Industrial	3,819	3,846	3,874	3,903	3,934
Total Other Ultimate	11	11	11	11	11
Total Ultimate Sales	7,914	7,959	8,015	8,068	8,127
Municipals	116	117	118	120	121
Total Sales-for-Resale	116	117	118	120	121
Total Internal Sales	8,029	8,076	8,134	8,188	8,248
Total Losses	736	743	743	755	761
Total Internal Energy	8,765	8,819	8,877	8,943	9,009
Internal Peak Demand (MW)					
Summer	1,441	1,448	1,462	1,474	1,483
Preceding Winter	1,756	1,773	1,785	1,793	1,800

Kentucky Power Company
Monthly Internal Load
2009

Prior to DSM Adjustments

Internal Energy (GWH)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential	335.4	263.5	231.2	161.2	135.9	167.6	205.3	204.5	159.2	140.4	192.7	296.6	2,493
Commercial	134.7	118.3	116.4	111.5	116.4	124.2	127.8	130.4	119.3	116.7	106.8	124.0	1,447
Industrial	272.8	264.6	278.5	274.6	282.9	271.4	259.0	278.3	252.8	279.6	273.8	271.1	3,259
Total Other Ultimate	1.1	0.8	0.9	0.8	0.8	0.6	0.8	0.8	0.7	1.0	1.0	1.1	10
Total Ultimate Sales	744.0	647.2	627.0	548.1	535.9	563.9	592.8	614.0	532.0	537.7	574.3	692.7	7,210
Municipals	9.6	9.9	9.1	8.1	7.5	7.6	8.3	8.6	8.3	7.6	7.8	8.7	101
Total Sales-for-Resale	9.6	9.9	9.1	8.1	7.5	7.6	8.3	8.6	8.3	7.6	7.8	8.7	101
Total Internal Sales	753.6	657.0	636.1	556.2	543.4	571.5	601.2	622.6	540.3	545.3	582.0	701.5	7,311
Total Losses	60.0	54.4	52.6	46.1	45.1	47.3	49.7	51.3	44.3	44.7	73.4	83.9	653
Total Internal Energy	813.6	711.5	688.7	602.3	588.5	618.8	650.8	673.9	584.6	590.0	655.5	785.3	7,964
Internal Peak Demand (MW)	1,519	1,615	1,296	1,130	1,060	1,193	1,220	1,309	1,141	1,038	1,311	1,518	1,615

Exhibit 2-18

Kentucky Power Company
Monthly Internal Load
2010

Prior to DSM Adjustments

Internal Energy (GWH)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Annual
Residential	335.1	264.5	232.5	157.0	131.0	159.1	206.2	200.2	158.7	132.8	188.8	302.7	2,469
Commercial	135.4	120.2	119.1	113.6	118.2	120.7	129.9	129.7	121.8	114.6	106.4	129.2	1,459
Industrial	281.3	273.4	292.8	287.8	295.2	278.2	269.7	288.8	266.1	298.2	295.6	301.7	3,429
Total Other Ultimate	1.1	0.8	0.9	0.8	0.8	0.6	0.8	0.8	0.7	1.0	1.0	1.1	10
Total Ultimate Sales	752.9	658.8	645.3	559.2	545.2	558.6	606.7	619.5	547.3	546.6	591.7	734.7	7,367
Municipals	9.7	10.0	9.2	8.3	7.7	7.8	8.6	8.8	8.5	7.8	8.0	9.0	103
Total Sales-for-Resale	9.7	10.0	9.2	8.3	7.7	7.8	8.6	8.8	8.5	7.8	8.0	9.0	103
Total Internal Sales	762.6	668.8	654.5	567.5	552.9	566.5	615.2	628.3	555.8	554.4	599.7	743.7	7,470
Total Losses	62.7	55.1	54.0	46.8	48.2	64.9	50.6	65.8	45.7	50.4	71.0	61.3	676
Total Internal Energy	825.4	723.9	708.5	614.2	601.1	631.3	665.9	694.1	601.5	604.8	670.7	804.9	8,146
Internal Peak Demand (MW)	1,544	1,640	1,349	1,151	1,075	1,214	1,248	1,338	1,169	1,063	1,339	1,548	1,640

Exhibit 2-19

AEP-East Zone
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2009-2023

After 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
2009	20,476	21,077	21,685	19,500	20,338	21,194	120,007	123,530	127,092
2010	20,288	21,160	22,051	20,720	21,726	22,770	117,085	122,116	127,259
2011	21,332	22,368	23,442	20,718	21,864	23,059	125,977	132,096	138,442
2012	21,411	22,595	23,830	20,769	22,130	23,557	126,602	133,603	140,906
2013	21,469	22,876	24,351	20,668	22,297	23,985	126,438	134,724	143,409
2014	21,393	23,079	24,826	20,703	22,456	24,248	125,748	135,657	145,927
2015	21,459	23,276	25,134	20,806	22,550	24,326	125,944	136,608	147,512
2016	21,612	23,423	25,268	20,904	22,702	24,545	126,979	137,621	148,463
2017	21,778	23,651	25,572	20,989	22,840	24,763	127,519	138,487	149,731
2018	21,897	23,828	25,834	21,062	22,976	24,972	128,027	139,317	151,047
2019	22,000	23,999	26,084	21,035	23,038	25,135	128,437	140,107	152,280
2020	22,016	24,112	26,307	21,226	23,268	25,411	128,667	140,917	153,744
2021	22,221	24,358	26,602	21,354	23,441	25,649	129,393	141,837	154,902
2022	22,380	24,566	26,881	21,412	23,561	25,867	130,171	142,889	156,350
2023	22,510	24,768	27,193	21,422	23,674	26,096	130,868	143,998	158,096
Average Annual Growth Rate % 2009-2023	0.7	1.2	1.6	0.7	1.1	1.5	0.6	1.1	1.6

Exhibit 2-20

Kentucky Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2009-2023

After DSM Adjustments

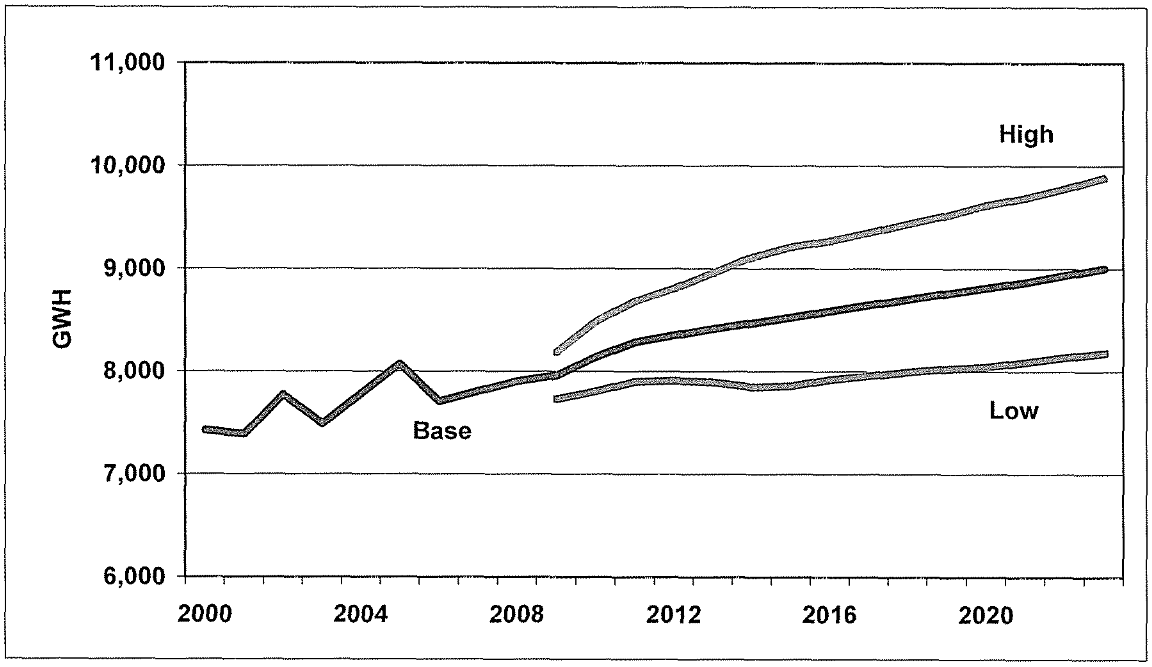
	Summer Peak Internal Demands (MW)			Winter (Following) Peak Internal Demands (MW)			Internal Energy Requirements (GWH)		
Year	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**	**Low Case**	**Base Case**	**High Case**
2009	1,271	1,308	1,346	1,572	1,639	1,708	7,735	7,963	8,192
2010	1,283	1,338	1,394	1,590	1,668	1,748	7,808	8,144	8,487
2011	1,294	1,357	1,422	1,584	1,672	1,763	7,902	8,286	8,684
2012	1,292	1,364	1,438	1,585	1,689	1,798	7,916	8,354	8,811
2013	1,294	1,379	1,468	1,576	1,700	1,829	7,899	8,417	8,959
2014	1,288	1,389	1,495	1,577	1,711	1,847	7,853	8,472	9,113
2015	1,291	1,400	1,512	1,585	1,717	1,853	7,864	8,530	9,210
2016	1,299	1,408	1,519	1,591	1,728	1,869	7,928	8,593	9,270
2017	1,308	1,420	1,535	1,598	1,739	1,885	7,965	8,651	9,353
2018	1,315	1,431	1,551	1,604	1,750	1,902	8,002	8,707	9,440
2019	1,321	1,441	1,566	1,602	1,754	1,914	8,032	8,762	9,523
2020	1,322	1,448	1,580	1,616	1,771	1,935	8,050	8,816	9,619
2021	1,334	1,462	1,597	1,625	1,784	1,952	8,096	8,874	9,692
2022	1,343	1,474	1,613	1,628	1,791	1,967	8,144	8,940	9,782
2023	1,348	1,483	1,629	1,628	1,799	1,983	8,185	9,007	9,888
Average Annual Growth Rate % 2009-2023	0.4	0.9	1.4	0.3	0.7	1.1	0.4	0.9	1.4

Exhibit 2-21

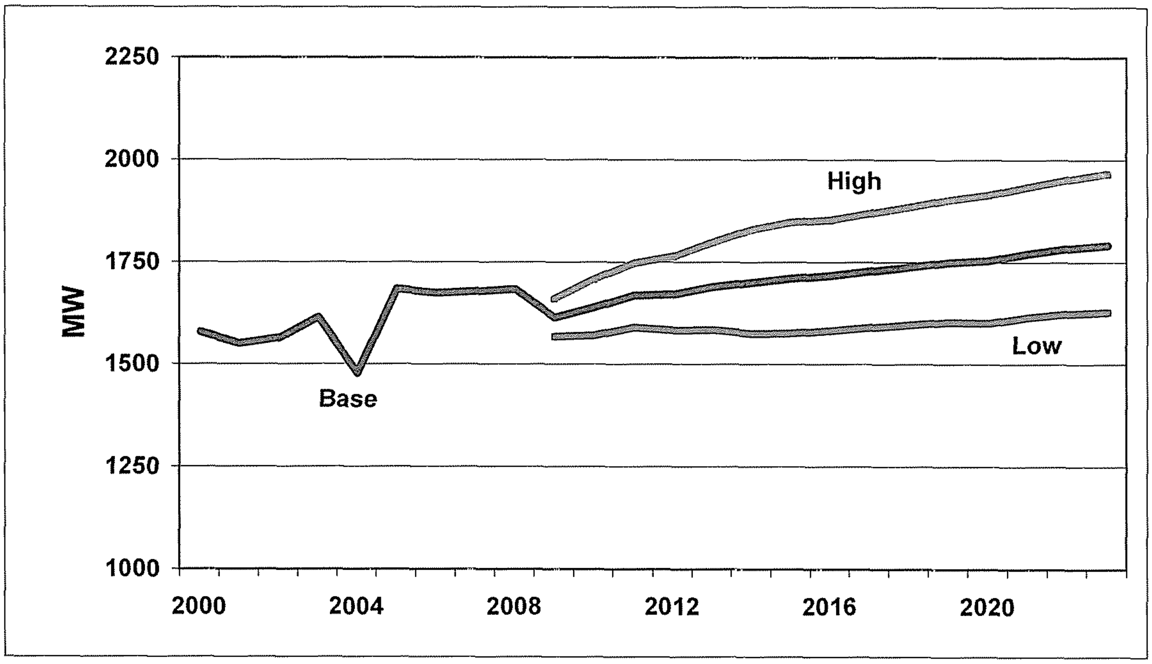
Exhibit 2-22

Kentucky Power Company
Range of Forecasts

Internal Energy Requirements



Winter Peak Demand



AEP-East Zone
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2009-2023

Prior to 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
2009	20,530	21,131	21,739	19,581	20,419	21,275	120,190	123,713	127,275
2010	20,425	21,297	22,188	20,811	21,818	22,861	117,571	122,601	127,745
2011	21,583	22,619	23,694	20,887	22,033	23,228	126,884	133,003	139,349
2012	21,665	22,849	24,084	20,941	22,302	23,729	127,519	134,520	141,823
2013	21,724	23,131	24,605	20,846	22,475	24,163	127,364	135,649	144,335
2014	21,651	23,336	25,084	20,881	22,634	24,427	126,680	136,589	146,859
2015	21,717	23,534	25,392	20,981	22,725	24,501	126,881	137,544	148,449
2016	21,866	23,677	25,522	21,079	22,877	24,720	127,920	138,561	149,403
2017	22,033	23,906	25,827	21,167	23,017	24,940	128,462	139,430	150,674
2018	22,153	24,084	26,090	21,241	23,154	25,151	128,970	140,260	151,991
2019	22,258	24,257	26,343	21,213	23,216	25,313	129,381	141,051	153,224
2020	22,274	24,370	26,565	21,399	23,441	25,584	129,610	141,861	154,688
2021	22,477	24,614	26,858	21,528	23,614	25,823	130,336	142,780	155,846
2022	22,634	24,821	27,135	21,586	23,734	26,041	131,114	143,832	157,293
2023	22,764	25,023	27,448	21,596	23,849	26,271	131,812	144,942	159,039
Average Annual Growth Rate % 2009-2023	0.7	1.2	1.7	0.7	1.1	1.5	0.7	1.1	1.6

Exhibit 2-23

Kentucky Power Company
Low, Base and High Case for
Forecasted Seasonal Peak Demands and Internal Energy Requirements
2009-2023

Prior to 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**
2009	1,271	1,309	1,346	1,569	1,615	1,662	7,737	7,964	8,193
2010	1,283	1,338	1,395	1,573	1,641	1,710	7,811	8,146	8,489
2011	1,294	1,357	1,422	1,592	1,669	1,750	7,906	8,290	8,688
2012	1,292	1,364	1,438	1,586	1,674	1,765	7,920	8,358	8,814
2013	1,294	1,379	1,468	1,587	1,691	1,800	7,903	8,420	8,963
2014	1,288	1,390	1,495	1,578	1,702	1,831	7,856	8,475	9,116
2015	1,291	1,400	1,512	1,579	1,712	1,849	7,867	8,533	9,214
2016	1,299	1,408	1,519	1,586	1,719	1,854	7,932	8,596	9,273
2017	1,308	1,420	1,535	1,593	1,730	1,870	7,969	8,654	9,356
2018	1,315	1,431	1,551	1,600	1,740	1,887	8,005	8,710	9,443
2019	1,321	1,441	1,566	1,605	1,751	1,903	8,035	8,765	9,526
2020	1,322	1,448	1,580	1,603	1,756	1,916	8,052	8,819	9,621
2021	1,334	1,462	1,597	1,618	1,773	1,936	8,098	8,877	9,694
2022	1,343	1,474	1,613	1,627	1,785	1,953	8,147	8,943	9,785
2023	1,348	1,483	1,629	1,629	1,793	1,968	8,188	9,009	9,891
Average Annual Growth Rate % 2009-2023	0.4	0.9	1.4	0.3	0.7	1.2	0.4	0.9	1.4

Exhibit 2-24

Kentucky Power Company and AEP-East Zone
Total Internal Energy Requirements
Comparison of 1999 and 2009 Forecasts

Prior to DSM Adjustments

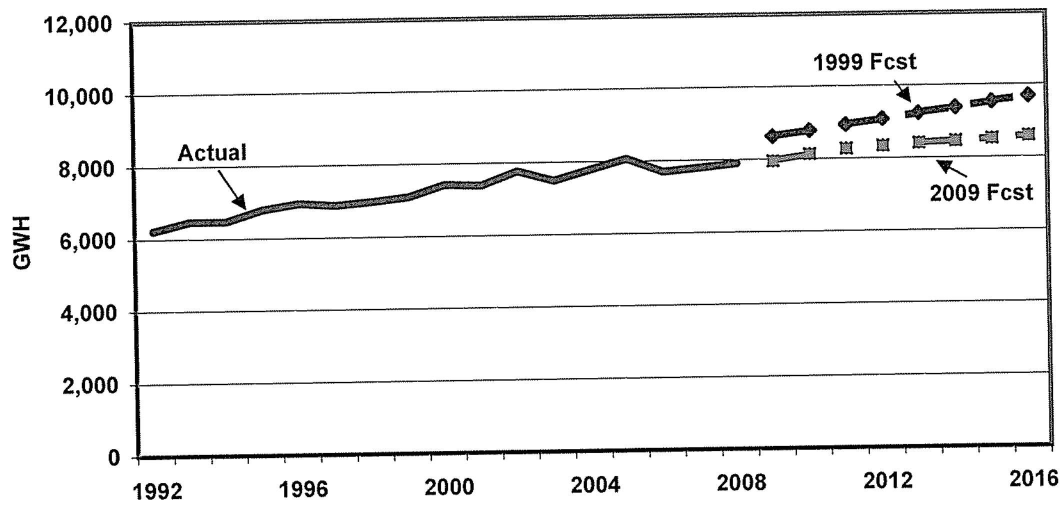
Forecast Year	KPCo 2009 Forecast GWH	KPCo 1999 Forecast GWH	KPCo Change From 1999 Forecast GWH	KPCo Change From 1999 Forecast Percent	AEP-East Zone 2009 Forecast GWH	AEP-East Zone 1999 Forecast GWH	AEP-East Zone Change From 1999 Forecast GWH	AEP-East Zone Change From 1999 Forecast Percent
1999	-	7,297	-	-	-	118,710	-	-
2000	-	7,406	-	-	-	116,116	-	-
2001	-	7,524	-	-	-	118,205	-	-
2002		7,632				120,268		
2003		7,746				122,358		
2004		7,895				124,168		
2005		8,045				125,978		
2006		8,194				127,788		
2007		8,343				129,598		
2008		8,493				131,408		
2009	7,964	8,642	-678	-7.8	123,713	133,219	-9,506	-7.1
2010	8,146	8,792	-646	-7.3	122,601	135,029	-12,428	-9.2
2011	8,290	8,941	-651	-7.3	133,003	136,839	-3,836	-2.8
2012	8,358	9,090	-732	-8.1	134,520	138,649	-4,129	-3.0
2013	8,420	9,240	-820	-8.9	135,649	140,459	-4,810	-3.4
2014	8,475	9,389	-914	-9.7	136,589	142,269	-5,680	-4.0
2015	8,533	9,538	-1,005	-10.5	137,544	144,079	-6,535	-4.5
2016	8,596	9,688	-1,092	-11.3	138,561	145,889	-7,328	-5.0
2009-2016 Growth Rate (%)	1.1	1.6			1.6	1.3		

Exhibit 2-25

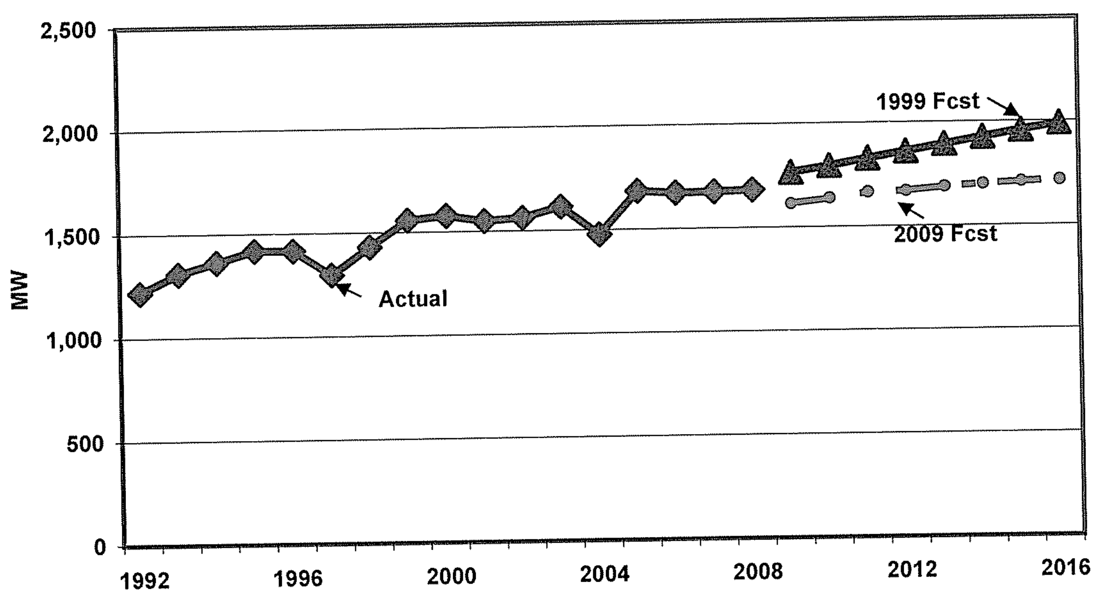
Exhibit 2-26

Kentucky Power Company
Comparison of Forecasts

Internal Energy Requirements



Winter Peak Demand



Kentucky Power Company and AEP-East Zone
Winter Peak Internal Demands
Comparison of 1999 and 2009 Forecasts

Prior to DSM Adjustments

Forecast Year	KPCo 2009 Forecast MW	KPCo 1999 Forecast MW	KPCo Change From 1996 Forecast MW	KPCo Change From 1996 Forecast Percent	AEP-East Zone 2009 Forecast MW	AEP-East Zone 1999 Forecast MW	AEP-East Zone Change From 1996 Forecast MW	AEP-East Zone Change From 1996 Forecast Percent
1999	-	1,462	-	-	-	19,082	-	-
2000	-	1,488	-	-	-	19,372	-	-
2001	-	1,512	-	-	-	19,660	-	-
2002		1,537				19,955		0.0
2003		1,570				20,244		0.0
2004		1,602				20,533		0.0
2005		1,635				20,821		0.0
2006		1,667				21,110		0.0
2007		1,699				21,399		0.0
2008		1,732				21,687		0.0
2009	1,614	1,764	-150	-8.5	20,419	21,976	-1,557	-7.1
2010	1,639	1,796	-157	-8.7	21,818	22,265	-447	-2.0
2011	1,668	1,829	-161	-8.8	22,033	22,553	-520	-2.3
2012	1,672	1,861	-189	-10.2	22,302	22,842	-540	-2.4
2013	1,689	1,894	-205	-10.8	22,475	23,131	-656	-2.8
2014	1,700	1,926	-226	-11.7	22,634	23,419	-785	-3.4
2015	1,711	1,958	-247	-12.6	22,725	23,708	-983	-4.1
2016	1,717	1,991	-274	-13.7	22,877	23,997	-1,120	-4.7
2009-2016 Growth Rate (%)	0.9	1.7			1.6	1.3		

Exhibit 2-27

Kentucky Power Company
Average Annual Number of Customers by Class
2004-2008

	2004	2005	2006	2007	2008
A. Residential					
1. Heating Customers	80,841	81,677	82,638	83,544	84,501
2. Nonheating Customers	63,593	62,836	61,809	60,663	59,605
3. Total	144,434	144,513	144,447	144,207	144,105
B. Commercial	28,289	28,867	29,284	29,686	29,729
C. Industrial					
1. Manufacturing	942	942	953	947	963
2. Mine Power	524	516	508	489	469
3. Total	1,466	1,457	1,460	1,437	1,433
D. Other Ultimate Sales					
1. Street Lighting	442	419	380	375	379
2. Other	0	0	0	0	0
3. Total	442	419	380	375	379
E. Total Ultimate Sales	174,630	175,256	175,572	175,704	175,646
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	174,632	175,258	175,574	175,706	175,648

Exhibit 2-28

Kentucky Power Company
Annual Internal Load by Class (GWH)
2004-2008

	2004	2005	2006	2007	2008
A. Residential					
1. Heating Customers	1,596	1,611	1,603	1,655	1,682
2. Nonheating Customers	816	836	807	830	799
3. Total	2,411	2,446	2,409	2,485	2,481
B. Commercial	1,373	1,423	1,392	1,446	1,429
C. Industrial					
1. Manufacturing	2,109	2,237	2,212	2,144	2,262
2. Mine Power	1,072	1,105	1,099	1,030	1,059
3. Total	3,181	3,343	3,311	3,174	3,322
D. Other Ultimate Sales					
1. Street Lighting	11	10	10	10	10
2. Other	0	0	0	0	0
3. Total	11	10	10	10	10
E. Total Ultimate Sales	6,977	7,222	7,122	7,115	7,242
F. Internal Sales for Resale					
1. Municipals	95	98	97	100	100
2. Other	0	0	0	0	0
3. Total	95	98	97	100	100
G. Total Internal Sales	7,072	7,319	7,220	7,215	7,342
H. Losses	720	665	747	723	609
I. Total Internal Load	7,791	7,984	7,966	7,937	7,951

Kentucky Power Company
Wholesale Customers
Coincident Seasonal Demand (MW) and Annual Energy (MWh)
2004-2008

Year	Summer Coincident Demand		Winter Following Coincident Demand		Energy	
	Vanceburg	Olive Hill	Vanceburg	Olive Hill	Vanceburg	Olive Hill
2004	11.4	5.2	14.7	5.6	67,137.1	28,034.2
2005	12.5	5.6	14.4	6.0	69,634.5	29,097.5
2006	13.7	5.8	3.4	6.9	70,308.4	28,281.5
2007	12.8	5.9	16.7	7.0	71,814.4	29,991.2
2008	12.0	4.9	16.0	7.1	71,578.3	29,732.6

Kentucky Power Company and AEP-East Zone
Recorded and Weather-Normalized Peak Load (MW) and Energy (GWH)
2004-2008

	2004	2005	2006	2007	2008
Kentucky Power Company					
A. Peak Load - Summer					
1. Recorded	1,228	1,358	1,292	1,348	1,249
2. Weather-Normalized	1,266	1,244	1,273	1,265	1,194
B. Peak Load - Winter					
1. Recorded	1,685	1,665	1,675	1,678	1,673
2. Weather-Normalized	1,595	1,438	1,428	1,573	1,561
C. Energy					
1. Recorded	7,790	8,072	7,709	7,808	7,907
2. Weather-Normalized	7,852	7,983	8,122	7,849	7,889
AEP-East Zone					
A. Peak Load - Summer					
1. Recorded	19,049	20,770	21,898	22,413	21,608
2. Weather-Normalized	19,474	20,411	20,473	21,657	19,823
B. Peak Load - Winter					
1. Recorded	19,796	19,604	21,702	21,977	22,270
2. Weather-Normalized	19,234	18,515	20,144	20,930	20,603
C. Energy					
1. Recorded	116,633	120,681	121,887	130,522	131,446
2. Weather-Normalized	117,649	119,358	123,720	128,958	131,583

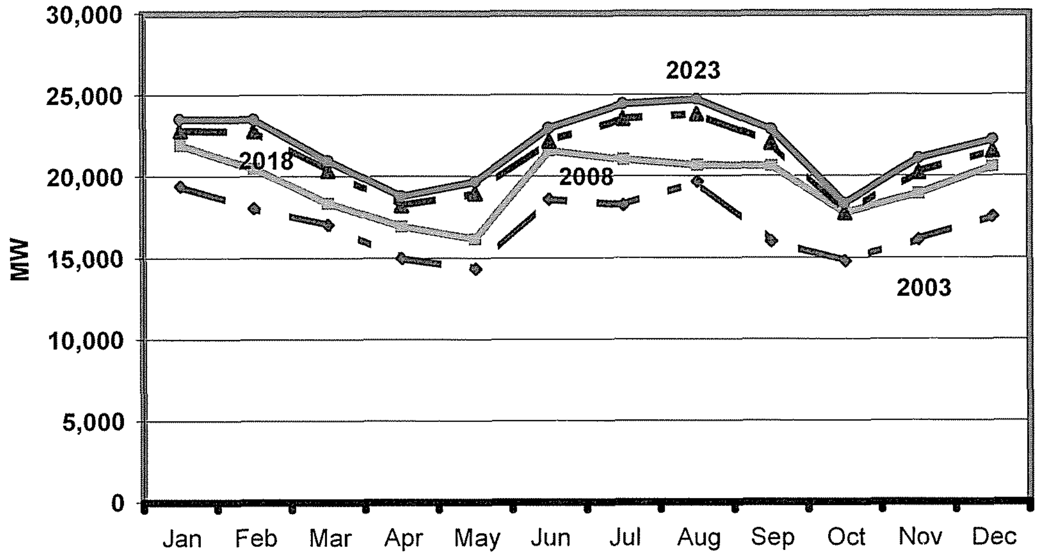
Kentucky Power Company
Normalized Annual Internal Sales by Class (GWH)
2004-2008

	2004	2005	2006	2007	2008
A. Residential	2,447	2,494	2,509	2,434	2,460
B. Commercial	1,381	1,405	1,418	1,424	1,429
C. Industrial	3,181	3,343	3,311	3,174	3,322
D. Other Ultimate Sales	11	10	10	10	10
E. Total Ultimate Sales	7,020	7,252	7,248	7,042	7,221
F. Internal Sales for Resale	96	96	98	99	100
G. Total Internal Sales	7,116	7,348	7,346	7,141	7,322

Exhibit 2-31

AEP-East Zone and Kentucky Power Company
Profiles of Monthly Peak Internal Demands
2003 and 2008 (Actual)
2018 and 2023

AEP-East Zone



Kentucky Power Company

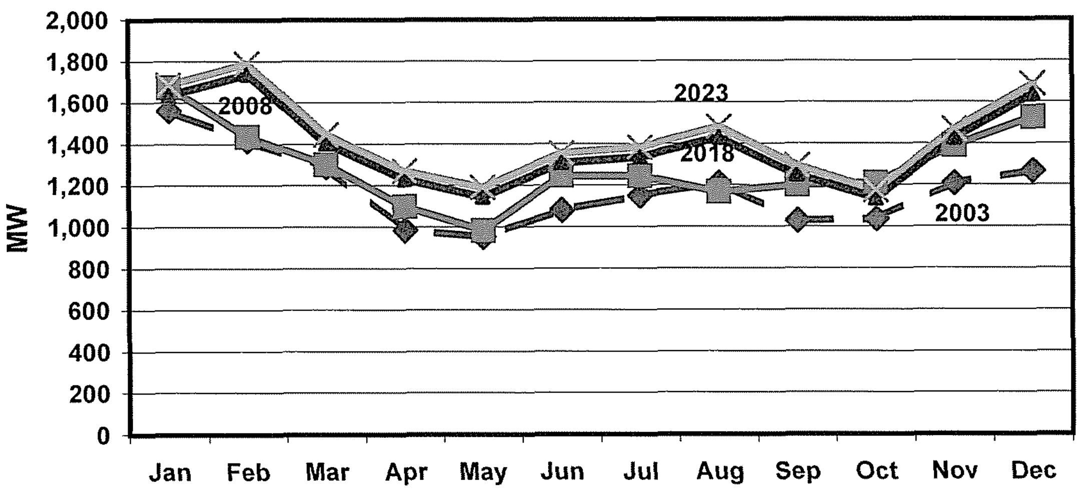


Exhibit 2-32

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	1975-2008	NOAA (1)	None
Heating and Cooling Degree-Days	Monthly	Selected weather stations throughout the AEP System	1/75-10/08	NOAA (1)	Annual Sums used in long-term models
FRB Production Index, Manufacturing	Monthly and Quarterly	U. S.	1984:1-2008:3 2008:4-2038:4	BOG/FRB (3) Moody's 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.	1984:1-2008:3 2008:4-2038:4	Moody's Economy.Com (2)	Annual averages used in long-term models
Index of Producer Prices-Industrial Commodities	Quarterly	U. S.	1984:1-2008:3 2008:4-2038:4	Moody's Economy.Com (2)	Annual averages used in long-term models
U. S. and Kentucky Natural Gas Prices by Sector	Annually	U. S.	1973-2007	DOE/EIA (4)	None
U. S. Coal Production and Consumption	Annually	U. S.	1975-2030	DOE/EIA (5)	None
Kentucky Coal Production	Annually	Selected Kentucky Counties	1975-2006	DMMCK (6)	None
Employment (Total and Selected Sectors), Gross Regional Product, Personal Income and Population	Annually	Selected Kentucky Counties	1975-2038	Moody's Economy.Com (2)	None

Source Citations:
(1) "Local Climatological Data," National Oceanographic and Atmospheric Administration.
(2) October 2008 Forecast, Moody's Economy.Com.
(3) Board of Governors of Federal Reserve System, "Federal Reserve Statistical Release," 1984-2008
(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 "2008 Annual Energy Outlook" and "Quarterly Coal Report," Selected Issues.
(6) Department of Mines and Minerals, Commonwealth of Kentucky "Annual Report," Selected Issues.

Exhibit 2-33

Kentucky Power Company
Residential Energy Sales
1999-2008
Actual vs. 1999 IRP

	Residential Energy Sales -GWH			
		1999	GWH	%
Year	Actual	Forecast	Difference	Difference
1999	2,158	2,315	-157	-6.8
2000	2,324	2,363	-39	-1.7
2001	2,312	2,409	-97	-4.0
2002	2,469	2,454	15	0.6
2003	2,357	2,499	-142	-5.7
2004	2,411	2,554	-143	-5.6
2005	2,534	2,610	-76	-2.9
2006	2,409	2,666	-257	-9.6
2007	2,485	2,722	-237	-8.7
2008	2,481	2,777	-296	-10.7

Exhibit 2-33

Exhibit 2-34

Kentucky Power Company
Seasonal Peak Demands
1999-2008
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
2002	1,326	1,291	35	2.7
2003	1,212	1,312	-100	-7.6
2004	1,228	1,336	-108	-8.1
2005	1,358	1,361	-3	-0.2
2006	1,292	1,385	-93	-6.7
2007	1,348	1,410	-62	-4.4
2008	1,249	1,434	-185	-12.9
Summer	Weather Normalized	1999 Forecast	MW Difference	% Difference
1999	1,153	1,231	-78	-6.3
2000	1,261	1,250	11	0.9
2001	1,252	1,270	-18	-1.4
2002	1,263	1,291	-28	-2.2
2003	1,249	1,312	-63	-4.8
2004	1,266	1,336	-70	-5.3
2005	1,244	1,361	-117	-8.6
2006	1,273	1,385	-112	-8.1
2007	1,265	1,410	-145	-10.3
2008	1,194	1,434	-240	-16.7

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
2002/03	1,564	1,537	27	1.8
2003/04	1,478	1,570	-92	-5.9
2004/05	1,685	1,602	83	5.2
2005/06	1,665	1,635	30	1.8
2006/07	1,675	1,667	8	0.5
2007/08	1,678	1,699	-21	-1.2
2008/09	1,673	1,732	-59	-3.4
Winter	Weather Normalized	1999 Forecast	MW Difference	% Difference
1999/00	1,495	1,462	33	2.3
2000/01	1,524	1,488	36	2.4
2001/02	1,559	1,512	47	3.1
2002/03	1,563	1,537	26	1.7
2003/04	1,572	1,570	2	0.1
2004/05	1,595	1,602	-7	-0.4
2005/06	1,438	1,635	-197	-12.0
2006/07	1,428	1,667	-239	-14.3
2007/08	1,573	1,699	-126	-7.4
2008/09	1,561	1,732	-171	-9.9

3. DEMAND-SIDE MANAGEMENT PROGRAMS

3. DEMAND-SIDE MANAGEMENT PROGRAMS

A. AEP DEMAND REDUCTION AND ENERGY EFFICIENCY PROGRAMS

A.1. Changing Conditions (807 KAR 5:058 Sec. 6)

Early in the decade, due to shifting trends in the regulatory and competitive arenas, the nature of DSM's role changed to a supplementary and complementary one in utility resource planning. The result was diminished levels of DSM. In the intervening years, conditions have changed greatly. Increasing costs of electrical capacity and energy, new legislation at the federal level (described briefly below), possible renewable resource mandates that would allow EE substitution, possible greenhouse gas legislation, and an apparent backing away from the trend to a competitive, deregulated industry, have brought about a renewed interest in DSM or DR/EE programs. Exhibit 3-1 shows the significant change from 1999 to 2009 in the amount of DR/EE that is contemplated in KPCo as well as the entire AEP-East Zone.

A.2. Existing Programs (807 KAR 5:058 Sec. 7.2.g.)

The AEP-System and KPCo have offered a variety of demand response and energy efficiency programs designed to encourage customers to use electricity efficiently, conserve energy and utilize cost-effective electrotechnologies. These include a series of information, education, and technical assistance, as well as financial incentive programs for our residential, commercial and industrial customers. For future years, KPCo will continue to experience the load impact benefits from these traditional DSM programs.

Existing programs include those that have been filed with and approved by the KPSC. These are the following:

1. Targeted Energy Efficiency Program,
2. High Efficiency Heat Pump -Mobile Home Program,
3. Mobile Home New Construction Program,
4. Modified Energy Fitness Program,
5. High Efficiency Heat Pump Program,
6. Energy Education for Students Program, and the
7. Community Outreach Compact Fluorescent Lighting (CFL) Program.

The first four of these programs are on-going, while new participants are now being sought for the High Efficiency Heat Pump Program, Energy Education for Students Program, and the Community Outreach Compact Fluorescent Lighting (CFL) Program. Descriptions of these existing programs can be found in Chapter 3- Appendix.

The effects of current programs, including those that have been filed with state commissions, are embedded in the load forecast. Subsequent energy and demand reductions are embodied in the general level of DR/EE that is established below in Chapters 3 and 4 of this IRP.

The Company has been continually working with the KPCo DSM Collaborative (which was established in November 1994 to develop KPCo's DSM plans) to ensure that DSM programs are implemented as effectively and efficiently as possible and are helping Kentucky customers save energy. Over the years, the KPCo DSM Collaborative has worked closely in reviewing, recommending and endorsing DSM programs for Kentucky Power. Through continuous monitoring the program performance, program participation level and DSM market potential, the Collaborative has recommended the addition, deletion and modification of various DSM programs for Kentucky Power. These past and present programs, along with DSM programs proposed by Collaborative for a 3-year extension beyond 2008, are described in detail in the KPCo DSM Collaborative Semi-Annual Status Report and Program Evaluation Reports filed with the Commission on August 25, 2008. The Collaborative also requested Commission approval for three new programs the High Efficiency Heat Pump, Energy Education for Students and the Community Outreach Compact Fluorescent Lighting (CFL) on August 25, 2008. The Company received Commission approval, by order dated November 25, 2008 in Case No. 2008-00350, to continue the existing KPCo Collaborative DSM programs through 2011. The Company also received Commission approval, by order dated February 24, 2009 in Case No. 2008-00349, to implement the three new DSM programs. The development of KPCo's DSM programs by the Collaborative incorporated the Collaborative's perspectives on those aspects of integrated resource planning that related to demand-side management.

B. DSM GOALS AND OBJECTIVES

Today's DSM programs continue to encourage the wise and prudent use of electricity, stressing activities that are cost-effective, promote efficiency, conserve, and alter consumption patterns. These programs are intended to benefit the consumer and conserve natural resources. The specific objectives of the Company's DSM activities are the same as those detailed in the 1996 and 1999 IRPs:

- Promoting energy conservation to all customers;
- Reducing future peak demands;
- Continuing efforts and cost-effective programs designed to provide the best possible service to customers;
- Promoting electric applications that improve system load factor;
- Striving for retention of existing customers;
- Encouraging new off-peak electrical applications; and
- Providing guidance and assistance to customers facing equipment replacement decisions

To be effective, programs have been tailored to meet local and regional needs and customer characteristics. The Company's new High Efficiency Heat Pump, Energy Education for Students and the Community Outreach Compact Fluorescent Lamp Program are examples of the programs tailored to meet local and regional needs and customer characteristics.

C. CUSTOMER & MARKET RESEARCH PROGRAMS

Successful demand-side management programs require a thorough understanding of customer electrical usage characteristics, appliance ownership, conservation activities, demographic characteristics, opinions and attitudes, and, perhaps most importantly, customers' needs for electric service. An understanding of these factors helps in the identification of load modifications, which may be advantageous to both the customer and the Company; permits an assessment of their potential impact; and helps in the development of programs to solicit customer participation. The Company utilizes data from the Company's load research studies, customer surveys, customer billing database and specific program related market research to obtain this information.

Load research and customer billing data were utilized to determine the specific customer and/or end-use demand and energy usage characteristics for DSM program evaluation. End-Use load research metering information, for example, associated with the evaluation of DSM programs on appliances such as heat pump, water heater, air conditioners, fluorescent lighting equipment, etc., has been collected, as appropriate, in previous evaluations.

The market research activities implemented by KPCo have included DSM market/process evaluation studies. These studies focused on assessing participant satisfaction with the various measures included in each DSM program, assisting in determining the impact on demand by persistence and by the number of freeriders, assessing the effectiveness of the program's delivery mechanisms, assisting in determining additional program/product benefits, and gaining insight into market potential. During 2006 – 2007 evaluation studies were conducted by selected vendors and KPCo DSM staff for the Mobile Home High-Efficiency Heat Pump Program, Mobile Home New Construction Program, Modified Energy Fitness Program and Targeted Energy Efficiency programs.

D. DSM PROGRAM SCREENING & EVALUATION PROCESS (807 KAR 5:058 Sec. 8.2.b.)

D.1. Overview

The process for evaluating DSM impacts for KPCo is practically divided into two spheres, "existing programs" and "future impacts". Existing programs, those programs that are well defined, follow a time worn process for screening and ultimate approval as explained below. Their impacts are propagated throughout the load forecast. Future impacts, less defined, are developed with a dynamic modeling process using generic cost and impact data and performed over the AEP-East operating area. This is described in Section E.

In the case of KPCo, the DSM Collaborative has been responsible for performing the function of DSM program screening and evaluation for Kentucky Power. The Collaborative, whose initial members represented residential, commercial, and industrial customers, was established to develop KPCo's DSM plans, including program designs, budgets and cost-recovery mechanisms.

The residential members of the Collaborative continue to review the KPCo DSM programs and modify them as appropriate.

For KPCo the evaluation process considers the DSM program's cost-effectiveness from all perspectives and incorporates cost-recovery mechanisms. In this regard, the Collaborative decides which DSM programs are to be screened for potential implementation in KPCo's service territory.

Through a continual monitoring process, the Collaborative has utilized a vast amount of data collected from each of the DSM programs to appropriately re-design and re-evaluate the programs so as to improve their cost-effectiveness and better target customers for the programs. Data obtained from load research, customer billing, customer surveys and market research have all been collected from the various DSM programs, and detailed load impacts have been estimated from the information acquired in the field. The Collaborative has provided DSM Status Reports to the Commission every six months since the start of program implementation in 1996, furnishing information on program participation levels, costs and estimated load impacts. Additionally, five KPCo DSM Evaluation Reports were submitted to the Commission, on August 15, 1997, August 16, 1999, August 14, 2002, August 15, 2005 and August 25, 2008, respectively. These reports provided extensive results of the screening and evaluation of each of the DSM programs implemented.

D.2. Existing Program Screening Process

The DSM screening process used by KPCo involved a cost-benefit analysis of each of the DSM programs the Collaborative proposed to continue beyond 2008. This included application of the Total Resource Cost (TRC) and Ratepayer Impact Measure (RIM) tests, as well as the Utility Cost (UC) test and the Participant (P) test, as defined in the California Standard Practice Manual. In this connection, the evaluation of the cost-effectiveness of a given DSM program involves the determination of the net present worth of the program's benefits and costs over the study period, which, in this case, was 2009-2028. Under the TRC test, such benefits and costs are viewed from the combined perspective of all rate-payers, whereas under the RIM test, the benefits and costs are viewed from the perspective of the non-participant, and is synonymously referred to as the "non-participant test". The benefits and costs under the UC test are viewed from the perspective of the utility, and under the Participant test, from the perspective of the program participant.

The major supply-side benefits used in the cost-benefit analysis of DSM programs are avoided energy (production) costs and avoided demand/capacity costs (for generation, transmission and distribution). These costs are valued on a marginal $/MWh and/or $/kW basis, as appropriate. A detailed approach (peak and off-peak periods, by season) was used to develop avoided production costs. Marginal production costs at peak and off-peak periods in the summer and winter seasons were applied to the appropriate DSM program impacts. The marginal production costs were estimated year-by-year for the forecast period based on a production cost computer model.

The benefits, costs and load impacts estimated in the cost-benefit analysis reflect the assumptions regarding replacement and persistence of each measure within the DSM programs over the study period. Also, the analysis considered the benefits from SO_2 emission credits, NO_X market price, estimates for CO_2 costs based on expected legislation, and expected additional system sales, thereby improving the cost effectiveness of each DSM measure.

D.3. Existing Program Screening & Evaluation Results

The Company, working with the Collaborative, continuously monitors the program performance, program participation level, DSM market potential and program marketing/delivery mechanisms. The Company has re-screened and re-evaluated four existing DSM programs and filed for a three-year extension with the Commission on August 25, 2008. In addition, the Company also screened three new DSM programs for cost effectiveness and received Commission approval on February 24, 2009 to implement the new programs.

D. 4. Existing Program Screening Methodology

The 1996 DSM screening methodology included a three-stage measure-screening process, plus a two-stage program-screening process. The 1999 DSM screening methodology reduced the number of screening stages by combining both the measure- and program-screening processes. Program costs and estimated achieved savings, as reported in the program evaluation reports, are utilized in the screening process on a prospective basis. Cost-effectiveness is determined at the program level over the average weighted life of the measures based on the California Standard Practice Manual. The DSM Collaborative has continued to be the decision-maker on the program-screening process since the initial design and implementation of the KPCo DSM programs.

D.5. Existing Programs Screening Assumptions

The avoided energy cost assumptions used in the screening process are developed using a production costing model. The model forecasts production costs for peak and off-peak hours. The capacity costs are based on capacity auction results in the PJM market with a transition to a gas turbine peaker cost in the subsequent, post-auction time frame. Energy costs, both on and off peak include all production costs including estimates for emissions costs.

D.6. Existing DSM Programs and Impacts

In 1999 KPCo's DSM program development included six residential DSM programs and two commercial DSM programs: Energy Fitness, TEE, High-Efficiency Heat Pump, High-Efficiency Heat Pump Mobile Home, Load Management Water Heating, Mobile Home New Construction, Commercial SMART® Audit and Commercial SMART® Incentive. The Load Management Water Heating Program was not included in the set of KPCo DSM Collaborative programs, but was approved separately under the Load Management Water Heating Provision of the Residential Service Tariff, which became effective April 1, 1997.

In 2001 the High-Efficiency Heat Pump Program was discontinued due to a lack of program participation. Commercial SMART® Audit and Commercial SMART® Incentive programs were discontinued in 2002 since the database of eligible customers was exhausted. Such customers had completed their audits and installed measures acceptable to them.

In 2008, the electric utility industry was increasing the number of DSM programs due to increased energy costs, new legislation at the federal level and possible greenhouse gas legislation. The AEP System significantly expanded the base of DSM programs within its footprint. KPCo, working with the DSM Collaborative, obtained Commission approval to continue the on-going Targeted Energy Efficiency, High Efficiency Heat Pump - Mobile Home, Mobile Home New Construction and Modified Energy Fitness programs.

On February 24, 2009, the Commission also approved the Collaborative's request to implement three new DSM programs: the High Efficiency Heat Pump, Energy Education for Students, and the Community Outreach Compact Fluorescent Lighting program. New participants are currently being sought for these programs.

In the near future, KPCo, working with the DSM Collaborative, will seek new Collaborative members from the commercial and industrial sectors. Potential new commercial and industrial programs will be screened and evaluated for cost-effectiveness for potential implementation in KPCo's service territory.

The continued impacts from these legacy programs are embedded in the load forecast and discussed in Chapter 2, Section F.

E. EVALUATING DR/EE IMPACTS FOR FUTURE PERIODS (807 KAR 5:058 Sec. 8.2.b.)

E.1. gridSMART^{SM}

The AEP-System continues to evaluate distribution technologies that operate off the gridSMART^{SM} platform. These include "smart meters" that allow the consumer of electricity to receive pricing signals, or variable rates, encouraging the migration of consumption from times of peak demand, to times when power is more readily available. Pilot programs employing smart meters are currently underway in Ohio and Indiana. The results of these pilots will greatly inform the impacts assigned to larger roll-outs of these meters, should they ultimately be approved.

The bulk of the impacts of the expanded EE/DR modeled in this IRP are the forecasted results of "traditional" residential, commercial and industrial EE/DR programs, including tariff offerings.

E.2. Energy Efficiency / Demand Response Mandates and Goals

In November of 2007, the federal Energy Independence and Security Act of 2007 ("EISA") became law. The Act requires, among other things, a phase-in of lighting efficiency standards, appliance standards, and building codes. The increased standards will have a discernable effect on energy consumption as is shown in Exhibit 3-2. Additionally, mandated levels of energy efficiency attainment, subject to cost effectiveness criteria, are in place in both Ohio and Michigan. Other states in the AEP-East Zone are contemplating standards, including Virginia, which has a voluntary 10% energy efficiency target by 2020.

The IRP does not assume that these targets will be explicitly met, preferring a more conservative approach that recognizes the mandates, but prepares for the possibility that costs or other factors may intercede, triggering a revision or, perhaps, reaffirmation of the targets. The time horizon associated with building fossil fuel supply options is such that there will be other opportunities to further rationalize the appropriate levels of peak demand reduction and energy efficiency for the zone, prior to financially committing to non-renewable supply options.

Internally, the AEP- System has committed to a peak demand reductions of 1,000 MW by year-end 2012 and energy reductions of 2,250 GWh for the entire AEP-System, approximately 60-65% of which is in the AEP-East Zone.

E.3. Assessment of Achievable Potential

The amount of Energy Efficiency and Demand Response that are available are typically described in three buckets: technical potential, economic potential, and achievable potential. Briefly, the technical potential encompasses all known efficiency improvements that are possible, regardless of cost, and thus, cost-effectiveness. The logical subset of this pool is the economic potential. Most commonly, the total resource cost test is used to define economic potential. This compares the avoided cost savings achieved over the life of a measure/program with its cost to implement it, regardless of who paid for it. The third set of efficiency assets is that which is achievable.
Of the total potential, only a fraction is achievable and only then over time. Why all economic measures are not adopted by rational consumers speaks to the existence of "market barriers". Barriers such as lack of access to capital and lack of information are addressed with utility-based energy efficiency and demand response programs. How much effort and money is deployed towards removing or lowering the barriers is a decision made state by state.

E.4. Determining Expanded Programs for the IRP

Market Potential Studies (MPS) have been commissioned for 10 of AEP's 11 jurisdictions. KPCo did not commission for a MPS due to its long standing commitment to DSM programs that commenced in the mid 1990s, and the relatively high cost of such a study. In the East Zone, at the time the analysis for this IRP was performed, only the Indiana MPS study was complete. Additionally, one national study of energy efficiency was published by the Electric Power Research Institute (EPRI). These two studies formed the basis for the expanded DSM analysis in the IRP.

The economic potential for Energy Efficiency lies in the 10-16% range (relative to the Baseline forecast) for the 20-year period presented in each of the two studies. More importantly, estimates for what is achievable are a 1.7% reduction after five years (Indiana MPS) and 3.3% after 12 years (EPRI). Both studies include periods of ramping up from a standing start.

Embedded in the load forecast are the effects of DR/EE programs that are either currently in place or have been filed with the appropriate regulatory commission. Primarily, these impacts result from the mandates in Ohio and Michigan.

The Indiana study was used as the basis for the construction of DR/EE "blocks" to be used in the modeling process. The blocks are proxies for actual programs that are likely to be implemented in any of the AEP-East Zone jurisdictions, incremental to the programs that have already been filed. The blocks have the cost, energy, and peak demand reduction characteristics of the recommended programs in the Indiana study.

E.5. Validating the Blocks (807 KAR 5:058 Sec. 8.3.e.1.)

Because the blocks represent possible programs as recommended by the Indiana MPS, the blocks should be economically cost effective. Prior to allowing Strategist to optimize with the blocks as possible assets, their impacts were validated using current avoided costs. Exhibit 3-3 shows the recommended programs and their relative cost effectiveness. To reduce the problem set for Strategist, not all of the recommended programs were available for selection. From the figure, the green programs were not modeled. The red programs were modeled but not selected. The yellow programs are representative of the proxy resources. Program end uses and customer classes are depicted on the above referenced exhibit.

Note all of the resources are cost effective with the exception of the Residential Low and Moderate Income Weatherization (RLMW). Because these programs are typically required in jurisdictions where energy efficiency is being implemented, its costs and impacts were included outside of the optimization process.

Not shown on the chart are the Commercial & Industrial Demand Response (CIDR) resource which would be off the chart on the upper left side, but still cost effective, and the Residential Peak Reduction which was not cost effective.

The use of these proxy resources is necessary to model supply-side and demand-side resources within the same optimization process. In no way does this process imply that these programs, in their current form and composition must be done in equal measure and in all jurisdictions. All states are different and may have specific rules regarding the ability of C&I customers to "opt out" of utility programs, influencing the ultimate portfolio mix. Some states, including Kentucky, have a collaborative process that can greatly influence the tenor and composition of a program portfolio. That said, these blocks provide a reasonable proxy for demand-side resources within the context of an optimization model.

E.6. Optimizing the Incremental EE/DR Resources (807 KAR 5:058 Sec. 8.3.e.3.)

Using the program characteristics, "blocks" were constructed of equal energy impacts, corresponding demand impacts and costs.

These constraints keep Strategist from selecting EE/DR resources faster than is practical. The result of the constraints is a roll out of programs that is consistent with both the Indiana MPS recommendations and the EPRI Reasonably Achievable level of demand side resources.

The result is a modeled level of expanded DSM that is reasonably achievable and has the characteristics of a typical portfolio of DSM programs.

Exhibit 3-4 shows the seasonal impact of the Expanded DSM on the AEP-East Zone and KPCo.

E.7. Expected Program Costs and Benefits (807 KAR 5:058 Sec. 8.3e.2,4, and 5.)

The estimated cost to KPCo's customers to implement the expanded programs are included in Exhibit 3.5. Programs are assumed to be funded through 2015. The effects were assumed to last through the forecast period. Whether additional funding is needed to maintain the effects or if they persist and manifest themselves as part of the load forecast will be learned over time.

The expected net benefit (avoided costs) – (total resource costs) of the expanded DSM Portfolio is approximately $4.5 million, as determined by *Strategist.*

E.8. Discussion and Conclusion

The assumption of aggressive peak demand reduction and energy efficiency achievements reflect not only mandated levels of EE/DR in Ohio and Michigan, but also the AEP-System's commitment to demand-side resources.

The amount of DSM/EE included in this Plan is significantly higher than past IRP plans have included. There are a few reasons why this is valid:

Mandates at the state (including Ohio and Michigan in the AEP-East Zone, to this point) and potentially at the federal level (Waxman-Markey proposed legislation has an energy efficiency component in addition to renewable energy standards), will encourage adoption of demand side resources at a pace higher than would have been reasonably forecast in the past.

- Increased awareness and acceptance of the purported link between global warming and the consumption of fossil fuels will drive increased adoption of conservation measures, independent of economic benefit.
- Increased interest in demand response from the introduction of emergency capacity programs from PJM. Because AEP-East has historically not been able to count the demand assets of customers who participate in the PJM program, the Company seeks to broaden its interruptible tariffs to accommodate customers who have previously not been eligible, primarily because of size.

As the mechanism for regulatory cost recovery and the appetite for utility-sponsored DR/EE is formalized through the legislative and ratemaking processes in the various jurisdictions in which the AEP-System operates, the amount and type of DSM programs will likely change.

The AEP-System and KPCo leadership have committed to initiatives that include the latest, most environmentally-friendly technologies and protocols. Adoption of these measures is predicated on securing adequate cost recovery. For this planning cycle, it is assumed that such recovery would be forthcoming.

F. KYDOE ISSUES ADDRESSED IN KPSC STAFF 2000 REPORT

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 DSM are restated from the Staff report and addressed below:

1. **Establish an AEP-owned energy service company (ESCO) or form joint ventures with (or purchase) one or more existing ESCO.**

   In a competitive electric power environment, the regulated distribution utility is generally precluded from marketing energy efficiency and demand-side management (EE/DSM) programs, which are performed by ESCOs. Kentucky never deregulated its electric industry and vertically integrated utilities like KPCo are able to provide or contract for EE/DSM services directly. Therefore, there is no compelling reason for KPCo to pursue the establishment of an affiliated ESCO.

2. **Use Local Integrated Resource Planning (LIRP)**

   Integrated Resource Planning assumes that the geographic region (system) to which it is applied is more or less homogeneous with regard to the basic cost and benefit parameters on which the plan is developed. There are certain circumstances in which this assumption may be less valid. For example, if a reasonably-sized (electrically) load area requires costly local transmission facility reinforcement, the location of supply or demand side resources within that region may be able to defer or offset some portion of the otherwise-required local transmission facilities. This would yield more favorable economic analysis results for such resources when considered for that area than for the aggregate system. Local Integrated Resource Planning (LIRP) is simply an extension of Integrated Resource Planning which takes into account such localized factors, when appropriate.

   A review of Kentucky Power system circumstances reveals little opportunity for the successful application of Local Integrated Resource Planning, as opposed to overall system-wide Integrated Resource Planning. There are no instances of cost factors for sizeable load areas which differ substantially from system-wide average values, or where high-cost transmission improvements could be deferred or offset by the addition of local supply side or demand side resources. Furthermore, the size of supply side resources applicable to such applications is generally smaller than the size of resources supported by system-wide planning, falling into a range in which there are definite economies of scale. Any potential savings in deferred / offset transmission facility expansion costs would have to more than offset the diseconomies associated with the utilization of smaller scale supply side resources.

Distributed technologies such as solar panels and batteries, while still expensive, are being explored as possible planning solutions. Costs are projected to decline for these technologies. As that happens, their viability as cost-effective alternatives for generation, transmission, and distribution infrastructure increases. Certainly, in the near future, any application of these non-traditional assets would be highly site-specific. The evolution of these technologies is continuously monitored.

3. Initiate a Comprehensive program in Commercial New Construction.

Since the inception of the KPCo DSM programs in May 1996 through December 31, 2002, KPCo and its DSM Collaborative offered the Smart Audit and Smart Financing Program to new construction customers by auditing the building design plans, identifying energy saving measures, and providing financial incentives for the implementation of recommended energy saving measures. The database of potential commercial customers decreased each year due to the number of customer contacts and audits. KPCo's database of potential customers was exhausted May 31, 2002. Beginning June 1, 2002, the implementation contractor began focusing all its resources on contacting previous Smart Audit participants to insure all customers who wanted to take advantage of the Commercial Smart Audit Incentive Program did so before the program ended December 31, 2002. In Case No. 2002-00304 the KPCo Collaborative requested stopping this program due to the lack of customer participation. The Commission in its Order in Case No. 2002-00304, dated September 24, 2002 and in Case No. 2005-00333, Order dated November 21, 2005, authorized the stopping of this program. As of June 30, 2002, 53 new construction customers have implemented recommended energy saving measures and received a financial incentive. However, almost all of the implemented measures were related to high efficiency HVAC and lighting equipment changeovers, with none performing extensive integrated building analysis to alter the basic new building design. The type of new commercial establishment in KPCo's eastern Kentucky service area (smaller in size compared to national average) and the significant up-front labor and capital requirements needed for developing a new integrated approach to transform the design of new commercial buildings hinder the acceptance and/or applicability of this type of commercial new construction program in KPCo's service area.

The type of program proposed in 1999 by the Kentucky DOE would be more applicable for larger size commercial buildings in a big city environment, and would require the development of long-term relationships with architects, engineering firms, builders, manufacturers, and building supply companies. The technical expertise and the financial requirements to implement this type program could be substantial before any program impacts could be realized. Generally the cost effectiveness of the program will need to be determined on an individual customer basis. Considering the uncertainties about the cost effectiveness of the program, the economy, and the limited applicability to the type of commercial establishments in the KPCo service area, KPCo does not foresee a need to implement a Commercial New Construction Program to assist commercial new building design at this time. The Company believes it would be more effective if such a program would be initiated and funded at the state level by a state agency.

4. Promote Cogeneration to Gain Thermal Efficiencies

As approved by the Public Service Commission of Kentucky, KPCo offers two tariffs, COGEN/SPP I and COGEN/SPP II, to customers with cogeneration and/or small power production facilities which qualify under Section 210 of the Public Utility Regulatory Policies Act of 1978. COGEN/SPP I applies to those which have a total design capacity of 100 kW or less; and COGEN/SPP II applies to those which have a total design capacity over 100 kW.

Although there are no KPCo customers currently receiving service under either COGEN/SPP tariff, the tariff offerings remain available to customers who want to install cogeneration. Because KPCo offers very low electric rates, cogeneration is a less attractive option from an economic standpoint, even when gains in thermal efficiency are included. Cogeneration may be a more viable option if KPCo rates were to increase to the point where it makes cogeneration a serious economic consideration.

5. Promote Distributed Generation and Green Power through net metering.

Since the Company's 1999 IRP filing, many changes have occurred in Kentucky regarding net metering. In 2004, the Kentucky Legislature enacted a statute requiring that each retail electric supplier make net metering available to customers. In 2008, the Kentucky Legislature amended that statute to include additional requirements as detailed below. Distributed generation technology options will continue to be developed for customers and the Company believes that promotion of distributed generation and green power through net metering must be reviewed closely in order to avoid the subsidy of such options by the remaining customers of an electric utilty or by the utility.

KPCo currently offers a Green Pricing Option Rider and Net Metering Service Tariff. The Green Pricing Option Rider allows customers who wish to support the generation of electricity by Renewable Resources to contract to purchase 100 kWh block(s). KPCo had 11 customers participating as of June 2009.

KPCo initiated a Net Metering Service Tariff in 2005 available to customers that install solar generation up to 15 kW. KPCo had 0 customers participating as of June 2009. On April 7, 2009 KPCo filed with the Kentucky Public Service Commission a revised Net Metering Tariff. The purpose of the revised tariff was to comply both with the Commission's January 8, 2009 newly established net metering guidelines and to comply with Senate Bill 83 as enacted by the Kentucky General Assembly during the 2008 Regular Session. Senate Bill 83 amended the then-existing statutory requirements for the net metering of electricity, which are codified in KRS 278.465 to KRS 278.467. A few of Senate Bill 83 amended provisions are as follows: (1) The definition of an "eligible electric generating facility" is expanded from solar only to include wind energy, biomass or biogas energy, and hydro-energy; (2) The maximum size of eligible generators is increased from 15 kW to 30 kW; (3) The limit at which the Commission may restrict new net metering customers is increased from 0.1 percent to 1.0 percent of a retail supplier's single-hour peak load; (4) Bill credits for generation fed back to the retail supplier in excess of the electricity supplied during the billing period are carried forward for the life of the account; and (5) The net metering customer is responsible for the cost of any upgrade to the interconnection that is required by an approved tariff. On April 24, 2009, the Commission suspended the Company's Net Metering Tariff through October 6, 2009 and the Company is currently awaiting the Commission's final ruling.

Prior to any further expansion of net metering service to other types of generation or larger systems, there needs to be an evaluation, determination and agreement of the structure of the net metering rates. In order to properly establish metering provisions, time-differentiated rates for generation service must be included. The cost to produce electricity is valued differently throughout the day. During peak periods, the cost to produce electricity is higher than average. Likewise, during off-peak periods, the cost to produce electricity is lower than average. Therefore, net metering provisions and electricity prices need to reflect these cost variations. It is generally not appropriate to offer net metering which provides an average credit/rate throughout the day. Such an approach would allow customers to utilize dispatchable/portable distributed generation (and operate green power production) during KPCo's low-cost, off-peak periods and receive a higher-than-average credit for this off-peak production. Such customer generation during the off-peak period does not benefit the utility generating the power during the high-peak, high-cost on-peak period when electricity is needed the most. Promoting distributed generation and green power through net metering should benefit all parties involved, and the manner to achieve this is through the use of time-differentiated rates for generation service.

In addition, prior to any future expansion of net metering services, the net metering provisions should never result in a reduction in charges for transmission or distribution service. The existence of distributed generation, which can have some generation value, does not eliminate or reduce the need for proper transmission and distribution facilities to meet the customer's power needs. Any net metering provision which provides credits for transmission or distribution service clearly establishes a subsidy for which there is no basis.

If structured properly to reflect the true costs and benefits of the generation provided through distributed generation and green power, a net metering program would likely achieve no more success than the current COGEN/SPP tariffs. Any non-cost-based incentives implemented to encourage distributed generation and green power for the societal good should not be borne by KPCo.

Over the past several years, the AEP System has offered Demand-Side Management (DSM) programs developed to encourage efficient use of electricity. KPCo recognizes its responsibility to encourage its customers to make wise use of energy consumption, and therefore it will continue to offer a variety of existing off-peak and interruptible tariffs for customers to achieve energy efficiency and cost savings. These tariffs are also designed to achieve the DSM objectives of peak load shifting, peak clipping and emergency load curtailment. These time-of-day and interruptible generation related service options currently in place in KPCo should be encouraged, resulting in generation benefits and lower rates for customers.

Off-Peak service options

KPCo's off-peak rates are designed to encourage customers to shift load from the on-peak period to the off-peak period. Customers participating in these tariffs benefit from lower off-peak rates for energy and demand shifted to or consumed during the off-peak period. Participating customers receive reduced rates and KPCo has the potential to reduce costs and realize efficiency gains in producing electricity.

KPCo offers time-of-day and load management time-of-day provisions to various groups of its customers. The time-of-day provision is generally available for residential customers and provides on-peak and off-peak energy charges. The load management time-of-day provision is available to customers who use energy-storage devices with time-differentiated load characteristics (generally equipment operating only during the off-peak hours).

Interruptible service provisions

KPCo offers Tariff C.S.-I.R.P. for interruptible service, which is essentially another DSM tool that provides industrial and commercial customers a reduced rate in exchange for their agreement to temporarily curtail their service when requested by the Company.

In view of the potential for temporary emergency operating conditions on the AEP System, and to provide additional options for customers, KPCo and other AEP operating companies also have made available Rider Emergency Curtailable Service (ECS). Rider Price Curtailable Service (PCS) is available for curtailments called on an economic basis. These riders are available to commercial and industrial customers who normally take firm service, with demands greater than 1 MW. In the event of curtailments, such customers receive a curtailable credit from the Company, based on the customer's curtailment and the respective pricing provisions of these riders.

The table shown below lists KPCo's tariffs that contain off-peak and interruptible provisions and provides a general description of the tariff as of May 30, 2009.

Tariff Schedule / Provision	**Tariff Description**
Tariff RS (LM Water Heating Provision) # of customers: 117	Available to residential customers who install a Company-approved load management water-heating system which consumes electrical energy primarily during off-peak hours specified by the Company and stores hot water for use during on-peak hours. This provision provides an off-peak energy charge.

Tariff RS-LMTOD # of customers: 188	Available to customers eligible for Tariff RS (Residential Service) who use energy storage devices with time- differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours and store energy for use during on-peak hours.
Tariff RS-TOD # of customers: 1	Available for residential electric service through one single-phase multiple-register meter capable of measuring electrical energy consumption during the on-peak and off-peak billing periods to individual residential customers.
Tariff SGS (LMTOD) # of customers: 1 Tariff MGS (LMTOD) # of customers: 53 Tariff LGS (LMTOD) # of customers: 9	Available to customers who use energy-storage devices with time-differentiated load characteristics approved by the Company which consume electrical energy only during off-peak hours specified by the Company and store energy for use during on-peak hours. This tariff provides on-peak and off-peak energy charges.
Tariff MGS-TOD # of customers: 75	Available for general service customers with normal maximum demands greater than 10 kW but less than 100 kW. This tariff provides on-peak and off-peak energy charges.
Tariff QP # of customers: 91	Available for commercial and industrial customers with demands less than 7,500 kW. This tariff provides on-peak and off-peak excess demand charges.
Tariff CIP - TOD # of customers: 17	Available for commercial and industrial customers with normal maximum demands of 7,500 kW and above. This tariff provides on-peak and off-peak demand charges.
Tariff CS – IRP # of customers: 0	Available to customers operating at subtransmission voltage or higher who contract for service under one of the Company's interruptible service options. The total contract capacity for all customers served under this tariff is limited to 60,000 kW.

Rider ECS (Emergency Curtailable Service) # of customers: 0	Customer's ECS load will be curtailed when an emergency condition exists on the AEP System. Rider ECS is available to customers normally taking firm service under Tariffs QP and CIP – TOD for their total capacity requirements from the Company. The customer must have an on-peak curtailable demand not less than 1 MW and will be compensated for curtailments under the provisions of Rider ECS. Customer selects one of two ECS curtailment options based upon maximum duration and credit amounts. Customer will be subject to curtailment for no more than 50 hours per season.
Rider PCS (Price Curtailable Service) # of customers: 0	Customer's PCS load will be curtailed at the Company's sole discretion. Rider PCS is available to customers normally taking firm service under Tariffs QP and CIP-TOD for their total capacity requirements from the Company. The customer must have an on-peak curtailable demand not less than 1 MW and will be compensated for curtailments under the provisions of Rider PCS. Customer selects one of three PCS curtailment duration options. Customer specifies the maximum number of days during the season that the customer will curtail. The customer also specifies the minimum price at which the customer would curtail. The Company, at its sole discretion, determines whether the customer will be curtailed given the customer's specified PCS curtailment options.
Tariff RTP (Experimental Real-Time Pricing Tariff) # of customers: 0	Available for Real-Time Pricing (RTP) service, on an experimental basis, to customers normally taking firm service under Tariffs Q.P. or C.I.P.-T.O.D. for their total capacity requirements from the Company. The customer pays real-time prices for load in excess of an amount designated by the customer. Tariff RTP offers customers the opportunity to manage their electric costs by shifting load from higher cost to lower cost pricing periods or by adding new load during lower price periods. The customer must have a demand of not less than 1 MW and specify at least 100 kW as being subject to this Tariff.

Note 1: Kentucky Power Company off-peak billing period is defined as 9 p.m. to 7 a.m. local time, Monday through Friday including all hours of Saturdays and Sundays.

Note 2: The tariff descriptions shown above are in summary form. To obtain a full description, please see the Company's tariff sheets and terms and conditions of service.

6. Support statewide and regional market transformation initiatives

As discussed in item 1 above, Kentucky never deregulated the electric utility industry and statewide retail markets did not materialize. KPCo continues to support regional wholesale markets as evidenced through our membership and participation in the PJM Regional Transmission Organization and FERC wholesale market proceedings.

G. CHAPTER 3 EXHIBITS

Exhibit 3-1
KPCo and AEP System-East Zone
Estimated Reduction in Forecasted
Energy Requirements and Peak Demand
Due to Expanded DSM Programs
For Years 2010, 2015 and 2020

Comparison of 1996, 1999 and 2009 Plans

	AEP System-East Zone			KPCo		
Reduction in Energy Requirements (GWh)	1996 Plan	1999 Plan	2009 Plan	1996 Plan	1999 Plan	2009 Plan
2010	174	68	835	56	7	37
2015	96	53	3037	35	5	119
2020	96	53	3044	35	5	118
Reduction in Winter Peak Demand (MW)						
2010/11	315	60	164	39	5	8
2015/16	240	40	588	27	3	24
2020/21	240	40	587	27	3	24

Note that AEP East System included all AEP wholly owned regulated and unregulated operating companies in the AEP East service area.

Exhibit 3-2: Impact of Legislation on Energy Consumption

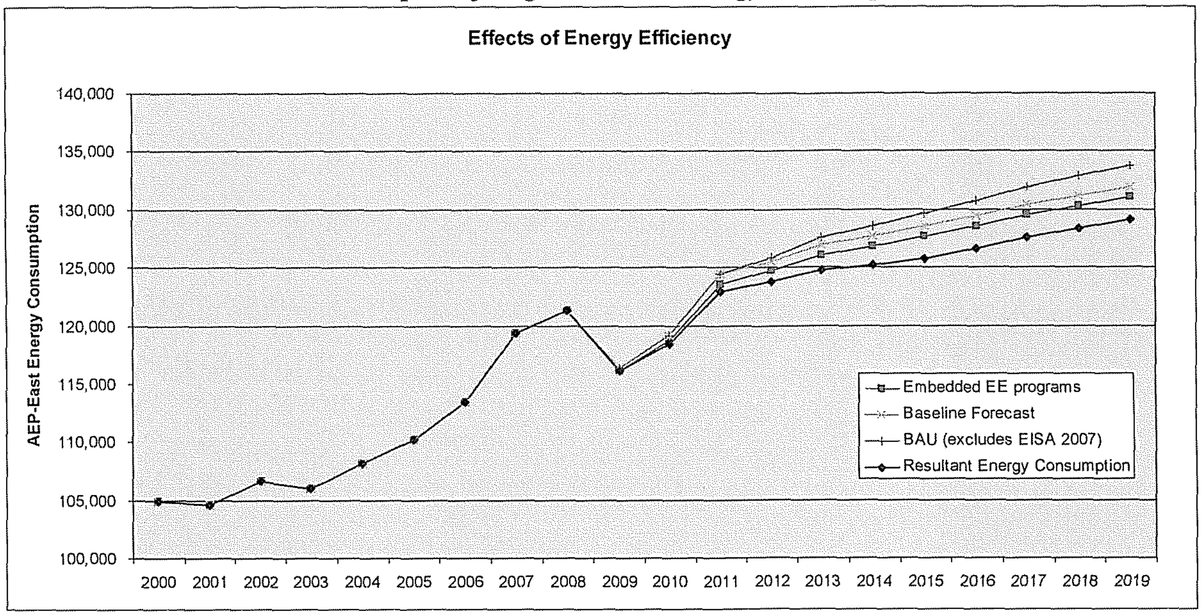


Exhibit 3-3: Cost Effectiveness of Relative Programs

(807 KAR 5:058 Sec. 8.3.e.1)

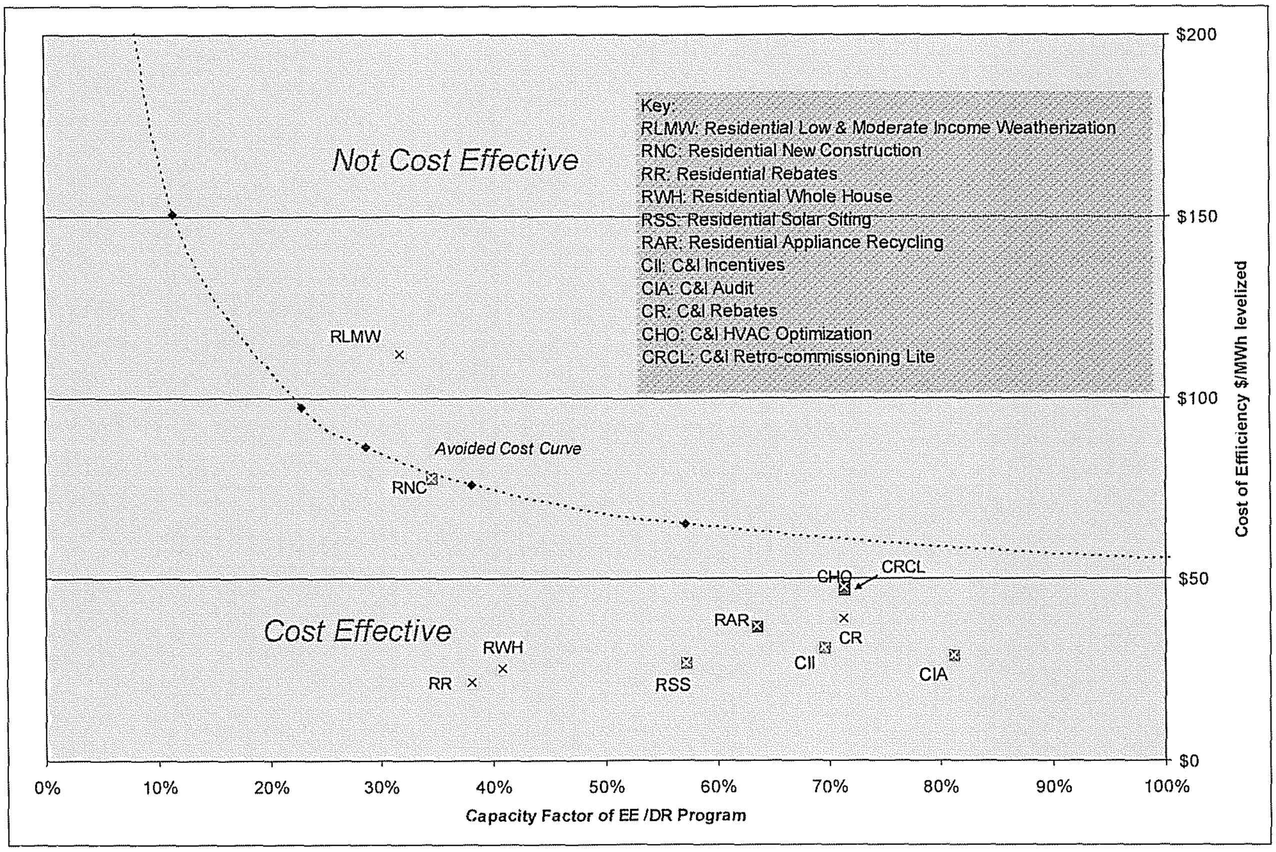


Exhibit 3-4: Expanded DR/EE Blocks Seasonal Impacts (AEP East Zone and KPCo)
(807 KAR 5:058 Sec. 8.3.e.3., Sec. 8.4.a.6. and Sec. 8.4.b.5.)

IRP Block Programs Impacts - KPCo

	2010	2011	2012	2013	2014	2015
Summer Peak Demand (MW)						
EE Programs	8	17	19	21	24	26
DR Programs	10	20	30	40	50	60
Total (MW)	18	37	49	61	74	86
Winter Peak Demand (MW)						
EE Programs	7	14	16	18	20	22
DR Programs	-	-	-	-	-	-
Total (MW)	7	14	16	18	20	22
Annual Energy Reductions (GWh)	35	73.5	84	94.5	105	115.5

IRP Block Programs Impacts - AEP-East Zone

	2010	2011	2012	2013	2014	2015
Summer Peak Demand (MW)						
EE Programs	79	158	237	316	394	473
DR Programs	100	200	300	400	500	600
Total (MW)	179	358	537	716	894	1,073
Winter Peak Demand (MW)						
EE Programs	67	134	202	269	336	403
DR Programs	-	-	-	-	-	-
Total (MW)	67	134	202	269	336	403
Annual Energy Reductions (GWh)	350	700	1050	1400	1750	2100

Exhibit 3-5: Expanded DR/EE Cost (KPCo)

(807 KAR 5:058 Sec. 8.3.e.4.)

Prospective Programs - KPCO ($thousands)

	2010	2011	2012	2013	2014	2015	Total
Incentives	5,744	6,449	2,007	2,057	2,109	2,162	20,527
Admin	862	967	301	309	316	324	3,079
Subtotal - Program Costs	6,605	7,416	2,308	2,366	2,425	2,486	23,607
Participant Costs	5,744	6,449	2,007	2,057	2,109	2,162	20,527
Total Resource Costs	12,349	13,864	4,316	4,424	4,534	4,648	44,134

H. CHAPTER 3, APPENDIX - DSM PROGRAM DESCRIPTIONS (807 KAR 5:058 Sec. 7.2g. and Sec. 8.3.e.1, 3-5)

TARGETED ENERGY EFFICIENCY PROGRAM

1. DESCRIPTION

This program is designed to perform energy audits and provide consultation, perform blower door test and install extensive weatherization and energy conservation measures targeted to electric space heating and/or electric water heating.

This program is proposed as a "piggyback" program, leveraging the resources of existing not-for-profit agencies that provide weatherization services to low-income households. These agencies (hereafter referred to as "Contractor") are:

Appalachian Service Project
Big Sandy Area Community Action Program
Leslie Knott Letcher Perry Community Action Council
Middle Kentucky River Area Development Council
Northeast Kentucky Area Development Council
Gateway Community Action Council

In the event federal funding cuts to the Weatherization Assistance Program (WAP) make it impossible for these agencies to fully utilize available Kentucky Power funding dollars, the program design will be adjusted to ensure continued program delivery.

This program includes two major components: electric heat and non-electric heat. The program, as proposed, will be year-round, targeted to high-use low-income customers, and include an energy audit and energy education for all selected households. The program will work as follows:

STEP ONE

Household selection based on usage and potential for savings.

WALK-AWAYS:

Households that are "walk-away's" due to:

* being too structurally deteriorated to merit going forward; or
* having too little potential for energy savings.

STEP TWO: FIRST HOME VISIT

This will require two people and will include:

Energy education with installation of simple measures where appropriate, including the following:

* hot water pipe insulation
* energy saving showerheads
* energy efficient light bulbs
* water heater wraps
* waterbed covers
* education.

STEP THREE: HEATING SYSTEM REPAIR

Based on experience, 80-90% of the houses will need some heating system repair in order to make air sealing safe. Repair and replacement work will be referred to WAP. Where old electric central heating systems should be replaced with energy-efficient heat pumps, this program will pay the incremental difference between the high-efficiency heat pump system cost and the electric central heating system cost, plus the additional cost of labor and venting. (A blower-door analysis with air sealing and duct sealing measures would be performed.) To be eligible, a household must have air conditioning or plans to add air conditioning. There will be no cost to the households for this measure. Educational measures on heat pumps will be provided in such cases.

STEP FOUR:

Weatherization based on energy audit and blower door analysis. Measures installed would be determined by: (a) heating type and (b) potential for savings, and include:

1. energy audit and inspection of heating equipment: all households
2. first-line weatherization (weatherstripping and caulking windows and exterior doors)
3. blower door analysis with air sealing and duct sealing measures
4. set water heater thermostats back
5. duct sealing
6. attic insulation
7. sidewall insulation
8. structural repairs that have energy efficiency value; i.e., holes in outside walls, outer doors, windows, ceilings
9. appliance replacement/removal.

STEP FIVE: FINAL INSPECTION

2. **RATIONALE FOR PROGRAM**

This program is designed to reduce usage and costs of qualified low-income customers, who comprise a large part of the Company's residential customer base. It will be targeted to high users and achieve savings through a combination of direct-install conservation measures based on an energy audit and energy education.

3. **PARTICIPATION GOALS**

	All-Elec Customers	Non-All-Elec Customers
Jan. 2009 thru Dec. 2009	210	78

4. **ELIGIBLE CUSTOMERS**

Residential retail customers in Kentucky Power's service territory who currently utilize an electric heating system and/or an electric water heater and use a minimum average of 700 kWh per month are eligible for participation.

5. **INCENTIVES**

No financial incentive is directly given to participants; however, the program is provided at no cost to the customer.

6. **IMPLEMENTATION PLAN**

A. Promotion

Kentucky Power will partner with Contractors to implement the program. The Community Action Agencies will accept applications and effect the screening process.

B. Delivery

The Contractor shall contact the customer directly, offer the program, and arrange for a time to implement the program at the customer's house.

C. Quality Assurance

The program will be regularly reviewed by Company staff responsible for managing the program's operation, as well as the Collaborative residential customer class sub-group.

D. Evaluation

A detailed evaluation plan will outline key research issues relating to the impact and process evaluations to be performed, along with the evaluation objectives, data collection procedures, and evaluation methodologies to be used, the evaluation schedule, reporting timelines, cost estimation, and a preliminary cost/benefit analysis.

Detailed information about each home will be collected by the Contractor for evaluating the program by KPC/AEPSC. Evaluation will include analysis by vendor selected by KPC/AEPSC. The program evaluation objectives are as follows:

1. Assess participant satisfaction with the energy conservation measures installed, the service performed by the Contractor, and the program as a whole;
2. Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness of energy conservation;
3. Determine the program load impact, including the energy savings and demand reduction, persistence and snap-back effects;
4. Assess the program cost-effectiveness based on the various economic tests;
5. Assess effectiveness of program delivery mechanism; specifically, the benefits gained in combining program implementation with other federally or state funded programs; and
6. Assess the impact the program has on customer payments, their ability to maintain service, and Company collection activities.

7. **TIMELINE**

Action	Start	End
Evaluation:		
First Report	01/08	06/08
Second Report	01/11	06/11

8. **ANNUAL BUDGET**

	Year 2009
Equipment / Vendor	$233,430
Incentives	0
Evaluation	0
TOTAL COSTS	$233,430

9. **EXPECTED SAVINGS / BENEFITS**

a. Anticipated Load Impact Per Participant:

1. Electric Heat Customers:
   Energy Savings Per Year = 2,032 kWh

2. Non Electric Heat Customers:
   Energy Savings Per Year = 1,136 kWh

10. COST / BENEFIT ANALYSIS

Benefit/cost ratios based upon the 2006-2007 program evaluation.

a.	Total Resource Cost	=	2.26
b.	Ratepayer Impact Measure	=	0.86
c.	Participant	=	N/A *
d.	Utility Cost	=	2.26

* Not applicable because of no participant costs.

HIGH EFFICIENCY HEAT PUMP – MOBILE HOME PROGRAM

1. **DESCRIPTION**
Kentucky Power will provide an incentive to customers to replace existing electric central furnaces with high-efficiency heat pump systems. Participants also must have an air conditioning system or plan to install one.

2. **RATIONALE FOR PROGRAM**
The high-efficiency heat pump program is designed to reduce residential electric energy consumption by replacing older, less efficient electric heating systems with high-efficiency heat pumps. Advanced technology has increased the efficiency of heat pump systems, resulting in higher energy savings and a greater demand reduction. This program is appropriate, as it helps keep electric bills lower for all customers and allows Kentucky Power to utilize its existing generating capacity more efficiently, thereby deferring the need for new generation as well as conserving our country's valuable natural resources.

3. **PARTICIPATION GOALS**

Jan. 2009 thru Dec. 2009	110 Customers

4. **ELIGIBLE CUSTOMERS**
Residential retail customers in Kentucky Power service territory who currently utilize electric heating and cooling systems (or plan to install a cooling system) are eligible to participate.

5. **INCENTIVES**
Kentucky Power will offer the customer a financial incentive to replace the existing electric heating equipment with a high-efficiency heat pump.

6. **IMPLEMENTATION PLAN**

A. Promotion
Kentucky Power will develop relationships with trade allies (i.e., manufacturers, dealers, contractors, architects, and engineers) in order to promote high-efficiency heat pump technology. Media advertising, such as newspaper, radio, television, and billboard, may also be used. A co-op advertising program may be offered to trade allies where the Company would share the cost of advertisements promoting high-efficiency heat pumps.

B. Delivery
Kentucky Power representatives will work in conjunction with trade allies to promote high-efficiency heat pumps in place of less efficient electric heating systems.

C. Quality Assurance
The program will be regularly reviewed by Company staff responsible for the program as well as the Company's DSM Collaborative residential customer class sub-group. They will maintain communication with trade allies as well as respond to any customer inquiries. A sample of installations may be inspected to verify quality of installation.

D. Evaluation
A detailed evaluation plan will outline key research issues relating to the impact and process evaluations to be performed, along with the evaluation objectives, data collection procedures, and evaluation methodologies to be used, the evaluation schedule, reporting time-lines, cost estimation, and a preliminary cost/benefit analysis.

The program evaluation objectives are as follows:

1. Assess participant satisfaction on the heat pump's operation, service performed by the contractor, company representative, and the program as a whole;
2. Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness of high-efficiency heat pumps;
3. Determine the program load impact, including the energy savings and demand reduction, as well as freeridership and snap-back effect;
4. Assess the effectiveness of the program delivery mechanism, including the efficiency of the program operation and marketing efforts and recommendations on program changes; and
5. Assess the program cost-effectiveness based on various economic tests.

7. **TIMELINE**

Action	**Start**	**End**
Evaluation:		
First Report	01/08	06/08
Second Report	01/11	06/11

8. **ANNUAL BUDGET**

	Year 2009
Equipment / Vendor	$ 5,500
Incentives	44,000
Evaluation	0
TOTAL COSTS	$ 49,500

9. **EXPECTED SAVINGS / BENEFITS**

Anticipated Load Impact Per Participant:

Electric Resistance Heating Replacement Customers:

Energy Savings Per Year	= 3,364 kWh
Demand Reduction	= 1.4 kW (@ system winter peak)
	= 0.7 kW (@ system summer peak)

10. **COST / BENEFIT ANALYSIS**

Benefit/cost ratios based on the 2006-2007 program evaluation.

a.	Total Resource Cost	=	9.79
b.	Ratepayer Impact Measure	=	3.45
c.	Participant	=	9.07
d.	Utility	=	6.02

MOBILE HOME NEW CONSTRUCTION PROGRAM,

1. **DESCRIPTION**

During the first year of this program, Kentucky Power Company or an outside vendor ("Contractor") will study the market for new mobile homes in the utility's service area for the purpose of determining the energy implications of current design and installation practices. In addition, KPC/AEPSC or Contractor will analyze the cost-effectiveness of a range of energy-related mobile home design options and will attempt to determine the level of financial incentives that would be needed to cause energy-efficiency features to be included in mobile homes. During Years 2 and 3, KPC/AEPSC will develop educational programs to boost the market demand for energy-efficient mobile homes. In addition, if the market analysis identifies cost-effective incentives that can enhance the energy efficiency of mobile homes offered for sale in the utility's service area, the Collaborative will develop a proposed budget for targeted incentives for consideration by the Public Service Commission.

2. **RATIONALE FOR PROGRAM**

In the Kentucky Power service territory, a significant percentage of all new residential construction consists of manufactured homes, also known as HUD-code or mobile homes. The goal of this program will be to help transform the market for such homes to the extent that a higher percentage of new manufactured homes sold in the area contain optimum levels of cost-effective energy efficiency design and construction features. In order to accomplish this goal, the Collaborative will work with all the parties involved in the distribution chain: manufacturers, distributors, installers, developers, lending institutions, and home buyers.

3. **ELIGIBLE CUSTOMERS**

Residential retail customers in Kentucky Power service territory who are in the market for newly constructed mobile homes. In addition, educational activities/ programs may be directed to mobile home manufacturers and/or dealers.

4. **IMPLEMENTATION PLAN**

A. Promotion

Kentucky Power will develop relationships with trade allies (i.e., manufacturers, dealers, and contractors) in order to determine what would be necessary to transform this market. Findings may lead to the development of a program of targeted incentives.

B. Delivery

Kentucky Power representatives will work in conjunction with trade allies to promote the manufacturing of more energy-efficient mobile homes.

C. Quality Assurance
The program will be regularly reviewed by Company staff responsible for the program as well as the Company's DSM Collaborative residential customer class sub-group. The Company will maintain communication with trade allies as well as respond to any customer inquiries.

D. Evaluation
The evaluation will consist of a market analysis for further implementation of the program and will be performed by the Contractor with input from KPC/AEPSC.

The program evaluation objectives are as follows:

1. Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness;
2. Determine the program's projected load impact, including the energy savings and demand reduction; and
3. Assess the effectiveness of the program delivery mechanism, including the efficiency of the program operation and marketing efforts and recommendations on program changes.

5. TIMELINE

Action	Start	End
Evaluation:		
First Report	01/08	06/08
Second Report	01/11	06/11

6. ANNUAL BUDGET

	Year 2009
Equipment / Vendor	$ 9,250
Incentives	92,500
Evaluation	0
TOTAL COSTS	$101,750

7. EXPECTED SAVINGS / BENEFITS

Anticipated Load Impact Per Participant:
Electric Resistance Heating Replacement Customers:

Energy Savings Per Year	= 2,073 kWh
Demand Reduction	= 1.6 kW (@ system winter peak)
	= 0.7 kW (@ system summer peak)

8. COST / BENEFIT ANALYSIS

Benefit/cost ratios based on the 2006-2007 program evaluation.

a.	Total Resource Cost	=	3.66
b.	Ratepayer Impact Measure	=	1.97
c.	Participant	=	3.81
d.	Utility	=	2.80

MODIFIED ENERGY FITNESS PROGRAM

1. **DESCRIPTION**

Residential customers utilizing electricity as their heating and water heating source will receive, at no cost to the customer, an energy audit and, where applicable, have installed a mixture of the following measures:

* energy-saving showerheads
* energy-efficient light bulbs
* water heater wraps
* switch and outlet gaskets
* waterbed covers
* programmable thermostats
* heating system inspection
* energy audit with blower door test
* first-line weatherization (weatherstripping and caulking of windows and interior doors)
* air sealing measures and duct sealing
* hot water pipe insulation
* set back water heater thermostat
* faucet aerators.

2. **RATIONALE FOR PROGRAM**

The audit and consultation will pinpoint energy conservation measures that can be implemented by a customer and educate the customer on the benefits of energy efficiency. Participants will be provided with the direct installation of appropriate energy conservation measures which can decrease energy consumption, lower their electric bills, and increase the comfort level of their homes.

3. **PARTICIPATION GOALS**

Jan. 2009 thru Dec. 2009	800 Customers

4. **ELIGIBLE CUSTOMERS**

Residential retail customers in American Electric Power – Kentucky Region service territory who currently utilize an electric heating system and an electric water heater and use a minimum average of 1,000 kWh per month are eligible for participation.

5. **IMPLEMENTATION PLAN**

a. Promotion

American Electric Power will contract with outside vendors("Contractor") to implement the program. The Contractor will accept applications and conduct the screening process.

b. Delivery

The Contractor shall contact the customer directly, offer the program, and arrange for a time to implement the program at the customer's house.

c. Quality Assurance

The program will be regularly reviewed by Company staff responsible for managing the program's operation, as well as the DSM Collaborative residential class sub-group.

d. Evaluation

A detailed evaluation plan will outline key research issues relating to the impact and process evaluations to be performed, along with the evaluation objectives, data collection procedures, and evaluation methodologies to be used, the evaluation schedule, reporting timelines, cost estimation, and a preliminary cost/benefit analysis.

Detailed information about each home will be collected by the Contractor for evaluating the program by AEP – Kentucky Region/AEPSC. The program evaluation objectives are as follows:

1) Assess participant satisfaction with the energy conservation measures installed, the service performed by the Contractor, and the program as a whole;

2) Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness of energy conservation;

3) Determine the program load impact, including the energy savings and demand reduction, as well as freeridership, persistence, and snap-back effects;

4) Assess effectiveness of program delivery mechanism, including the efficiency of program operation and promotional efforts and recommendations on program changes; and

5) Assess the program cost-effectiveness based on various economic tests.

6. TIMELINE

Action	**Start**	**End**
Evaluation:		
First Report	01/08	06/08
Second Report	01/11	06/11

7. **ANNUAL BUDGET**

	Year 2009
Equipment / Vendor	$304,000
Incentives	0
Evaluation	0
TOTAL COSTS	$304,000

8. **EXPECTED SAVINGS/BENEFITS**

Anticipated Load Impact Per Participant:

Energy Savings Per Year = 870 kWh

9. **COST / BENEFIT ANALYSIS**

Benefit/cost ratios based on 2006 – 2007 program evaluation.

a.	Total Resource Cost	=	3.37
b.	Ratepayer Impact Measure	=	1.43
c.	Participant	=	N/A
d.	Utility	=	3.37

HIGH EFFICIENCY HEAT PUMP PROGRAM

1. **DESCRIPTION**
Kentucky Power Company (KPCo) will offer a financial incentive to residential customers living in site-built homes who purchase a new high-efficiency heat pump for upgrades of less efficient electric heating and cooling systems.

2. **RATIONALE FOR PROGRAM**
The high-efficiency heat pump program is designed to reduce residential electric energy consumption by upgrading less efficient electric heating and cooling systems with high-efficiency heat pumps. Advanced technology has increased the efficiency of heat pump systems, resulting in higher energy savings and a greater demand reduction. This program is appropriate, as it helps lower electric bills for all residential customers and allows KPCo to utilize its existing generating capacity more efficiently, thereby deferring the need for new generation as well as conserving our country's valuable natural resources.

3. **PARTICIPATION GOALS**

	Resistant Heat Replacement	Heat Pump Replacement
Jan. 2009 thru Dec. 2009	50	50
Jan. 2010 thru Dec. 2010	100	100
Jan. 2011 thru Dec. 2011	100	100

4. **ELIGIBLE CUSTOMERS**
Residential retail customers living in the KPCo service territory who currently utilize an electric central heating and cooling system (or plan to install a central cooling system) are eligible to participate and receive financial incentives. Dealers installing qualifying equipment in homes of customers as outlined above will also be eligible to receive an incentive.

5. **INCENTIVES**
KPCo will offer customers and the HVAC dealer a financial incentive according to predetermined guidelines based on the efficiency (cooling SEER, heating HSPF) of the installed unit. The incentive will be structured as follows:

For upgrades of an electric resistance heating system with a high efficiency heat pump unit (SEER greater than or equal to 13; HSPF greater than or equal to 7.7), the residential customer will receive an incentive of $400.00. An incentive of $50.00 will be given to the participating HVAC dealer.

For upgrades of an electric heat pump unit with an ultra-high efficiency heat pump unit (SEER greater than or equal to 14; HSPF greater than or equal to 8.2), the residential customer will receive an incentive of $400.00. An incentive of $50.00 will be given to the participating HVAC dealer.

6. IMPLEMENTATION PLAN

A. Promotion

KPCo will develop relationships with trade allies (i.e., manufacturers, dealers, and contractors) in order to promote high-efficiency heat pump technology. Media advertising, such as newspaper, radio, television, and billboard, may also be used. A co-op advertising program may be offered to trade allies where the Company would share the cost of advertisements promoting high-efficiency heat pumps.

B. Delivery

KPCo representatives will work in conjunction with trade allies to promote high efficiency heat pumps in place of less efficient electric heating and cooling systems.

C. Quality Assurance

The program will be regularly reviewed by KPCo staff responsible for the program as well as the Company's DSM Collaborative. The Company will maintain communication with trade allies as well as respond to any customer inquiries. A selected sample of installations will be inspected to verify quality of installation.

D. Evaluation

KPCo will perform an evaluation relating to the program's impact and processes, including program objectives, data collection procedures, quality assurance methodologies, reporting timelines, costs, and the program's cost/benefit analyses.

The program evaluation objectives will be to:

1. Assess participant satisfaction with the program;
2. Gain insight into the market potential, including the participant characteristics, participation rate, and customer awareness of energy efficiency;
3. Determine the program impacts, including energy savings (KWh) and demand reduction (kW), and program value to customers;
4. Assess the program's cost-effectiveness based on various economic tests;
5. Assess the effectiveness of program delivery mechanisms.

7. **TIMELINE**

Action	Start	End
Program Approval	08/08	10/08
Implementation	01/09	12/11
Evaluation	01/10	06/10*
	01/11	06/11*

* Evaluation report will be provided on 08/15/10 and 08/15/11.

8. **ANNUAL BUDGET**

	Year 1	Year 2	Year 3
Program Incentives	$45,000	$ 90,000	$ 90,000
Promotion	$ 8,000	$ 8,000	$ 8,000
Evaluation	$ 0.000	$ 7.000	$ 7.000
TOTAL COSTS	$53,000	$105,000	$105,000

9. **EXPECTED SAVINGS / BENEFITS**

a. Anticipated load Impact Per Participant :

Upgrading Resistant Heat to Heat Pump Customers:

Energy Savings Per Year	4,176	kWh
Demand Reduction	2.900	kW @ system winter peak
	0.000	kW @ system summer peak

Upgrading Heat Pump Customers:

Energy Savings Per Year	858	kWh
Demand Reduction	0.444	kW @ system winter peak
	0.235	kW @ system summer peak

b. Annual Expected Program Savings/Benefits (including T&D losses) @ 200 units in one year:

Summer Peak Demand (kW) Reduction	Winter Peak Demand (kW) Reduction	Annual Energy (MWh) Reduction
18 kW	327 kW	462 MWh

Projected energy savings and demand reductions are estimated based on the anticipated number of installations. The estimated effects of freeriders are included.

c. Projected Program MWh Savings and kW Reduction Assuming Participation (Including T&D losses):

Goal of 500 units is achieved (all customers in three years)

Energy Savings	=	1,155	MWh
Demand Reduction	=	818	kW (@ system winter peak)
	=	45	kW (@ system summer peak)

10. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on the best information available at the time of Program design.

a.	Total Resource Cost	=	2.64
b.	Ratepayer Impact Measure	=	1.59
c.	Participant	=	1.93
d.	Utility Cost	=	5.40

ENERGY EDUCATION FOR STUDENTS PROGRAM

1. DESCRIPTION

Kentucky Power Company (KPCo) will partner with the National Energy Education Development Project (NEED) to implement an energy education program at participating middle schools throughout the KPCo service territory.

2. ELIGIBLE PARTICIPANTS

All 7th grade students at participating schools will be eligible for the program.

3. PARTICIPATION GOALS

Jan. 2009 through Dec. 2009	1,200 Students
Jan. 2010 through Dec. 2010	1,700 Students
Jan. 2011 through Dec. 2011	2,000 Students

4. IMPLEMENTATION PLAN

A. Promotion

NEED staff will conduct training workshops on a scheduled basis to ensure all participating schools are reached during a calendar year. Educational materials on energy, electricity, environment and economics will be provided. The program will also provide a package of four 23 watt compact fluorescent lamps (CFLs) that will allow students to directly install the CFLs in their homes as it relates to the curriculum. This allows learning and direct savings from the program.

B. Delivery

NEED staff will mail invitations to each middle school within the KPCo service territory. KPCo and NEED staff members will coordinate the enrollment of participating schools, delivery of educational materials & compact fluorescent lamps and scheduling of educational workshops.

5. EVALUATION

A. Goals

KPCo will perform an evaluation assessing and documenting the program's processes and estimating the program's impacts as well as performing a benefit/cost analysis.

B. Objectives

The program evaluation objectives will be to:

1. Assess educator and student satisfaction with the program;
2. Gain insight into the potential for expanding the program to additional grade levels;
3. Determine the program impacts, including energy savings (KWh) and demand reduction (kW), and program value to educators and students;
4. Assess the program's cost-effectiveness based on various economic tests;

6. **TIMELINE**

Action	Start	End
Program Approval	08/08	10/08
Implementation	01/09	12/11
Evaluation	01/10	06/10*
	01/11	06/11*

* Evaluation report will be provided on 08/15/10 and 08/15/11.

7. **ANNUAL BUDGET**

	Year 1	Year 2	Year 3
Program Development & Admin.	$ 4,000	$ 3,000	$ 3,000
Promotion	$ 1,000	$ 1,000	$ 1,000
Educational Workshops (incl. food)	$ 5,000	$ 5,000	$ 5,000
Compact Fluorescent Lamps	$12,000	$17,000	$ 20,000
Evaluation	$ 0,000	$ 5,000	$ 5,000
TOTAL COSTS	$22,000	$31,000	$34,000

8. **EXPECTED SAVINGS / BENEFITS**

a. Anticipated load Impact Per Lamp:

Energy Savings Per Year	46	kWh
Demand Reduction	.023	kW @ system winter peak
	.001	kW @ system summer peak

b. Annual Expected Program Savings/Benefits @ 4,800 CFLs in one year:

Summer Peak Demand (kW) Reduction	Winter Peak Demand (kW) Reduction	Annual Energy (MWh) Reduction
4	110	220.8

Projected energy savings and demand reductions are estimated based on the anticipated number of students living within the KPCo service territory and installing compact fluorescent lamps in their homes.

c. Projected Program MWh Savings and kW Reduction Assuming Participation: Goal of 19,600 CFLs is achieved (all students in three years)

Energy Savings	901.6 MWh
Demand Reduction	451 kW @ system winter peak
	18 kW @ system summer peak

9. **COST / BENEFIT ANALYSIS**

Benefit / cost ratios based on the best information available at the time of program design.

a.	Total Resource Cost	=	11.21
b.	Ratepayer Impact Measure	=	2.84
c.	Participant	=	29.31
d.	Utility Cost	=	21.64

COMMUNITY OUTREACH COMPACT FLUORESCENT LIGHTING (CFL) PROGRAM

1. **DESCRIPTION**

This program is designed to educate and influence Kentucky Power Company (KPCo) residential customers to purchase and use compact fluorescent lighting (CFLs) in their homes. To encourage customers to purchase CFLs as replacements for incandescent bulbs, a package of four 23 watt CFLs will be distributed to customers attending community outreach activities sponsored by KPCo.

2. **ELIGIBLE PARTICIPANTS**

Residential retail customers in Kentucky Power's service territory are eligible to participate.

3. **PARTICIPATION GOALS**

Jan. 2009 through Dec. 2009	3,500 customers
Jan. 2010 through Dec. 2010	4,000 customers
Jan. 2011 through Dec. 2011	4,000 customers

4. **IMPLEMENTATION PLAN**

A. Promotion

KPCo will promote the CFL program through the use of Consumer Circuit, advertising and community outreach activities. Consumer Circuit will be cycled through the KPCo's service territory.

B. Delivery

KPCo will devise and implement procedures to obtain the customer's account number, his/her name and electric service billing address in order for the CFL to be provided to KPCo customers (information will be used for follow up measurement and verification, and customer satisfaction).

5. **EVALUATION**

A. Goals

KPCo will perform an evaluation assessing and documenting the program's processes and estimating the program's impacts as well as performing a benefit/cost analysis.

B. Objectives

The program evaluation objectives are to:

1. Assess participant satisfaction with the program; Survey
2. Quantify the participant characteristics, participation rate, and installation rate.
3. Estimate the program impacts, including energy savings (kWh) and demand reduction (kW), and program value to customers;
4. Assess the program's cost-effectiveness based on various economic tests;
5. Assess the effectiveness of program delivery mechanisms.

C. Methodology
KPCo or its contractor/affiliate will periodically survey the parties receiving the compact fluorescent lamps. Survey questions will address customer satisfaction, installation information, program awareness, hours of operation, and future purchase intentions, and customer status.

6. **TIMELINE**

Action	Start	End
Program Approval	08/08	10/08
Implementation	01/09	12/11
Evaluation	01/10	06/10*
	01/11	06/11*

* Evaluation report will be provided on 08/15/10 and 08/15/11.

7. **ANNUAL BUDGET**

	Year 1	Year 2	Year 3
CFLs	$35,000	$40,000	$40,000
Promotion	$ 3,200	$ 3,900	$ 4,000
Administration	$ 2,000	$ 2,000	$ 2,000
Evaluation	$ 0,000	$ 8,000	$ 8,000
TOTAL COSTS	$40,200	$53,900	$54,000

8. **EXPECTED SAVINGS / BENEFITS**

a. Anticipated Load Impact Per Lamp :

Energy Savings Year	46	kWh
Demand Reduction	.023	kW @ system winter peak
	.001	kW @ system summer peak

b. Annual Expected Program Savings/Benefits
@ 14,000 bulbs in one year:

Summer Peak Demand (kW) Reduction	Winter Peak Demand (kW) Reduction	Annual Energy (MWh) Reduction
13	322	644

Projected energy savings and demand reductions are estimated based on the anticipated number of compact fluorescent lamps installed. Estimated effects of freeriders are not included.

c. Projected Program MWh Savings and kW Reduction
AssumingParticipation:
Goal of 46,000 bulbs is achieved (all customers in three years)

Energy Savings	2,116 MWh
Demand Reduction	1.1 MW @ system winter peak
	0.042 MW @ system summer peak

9. COST / BENEFIT ANALYSIS

Benefit / cost ratios based on the best information available at the time of program design.

a.	Total Resource Cost	=	13.05
b.	Ratepayer impact Measure	=	3.05
c.	Participant	=	29.05
d.	Utility Cost	=	30.08

4. RESOURCE FORECAST

4. RESOURCE FORECAST
(807 KAR 5:058 Sec.8.1. and Sec. 8.2.d.)

A. RESOURCE PLANNING OBJECTIVES (807 KAR 5:058 Sec.8.5.a. and Sec. 8.5.c.)

The primary objective of power system planning is to assure the reliable, adequate and economical supply of electric power and energy to the consumer, in an environmentally compatible manner. Implicit in this primary objective are related objectives, which include, in part: (1) maximizing the efficiency of operation of the power supply system, and (2) encouraging the wise and efficient use of energy.

Other objectives of a resource plan include planning flexibility, creation of an optimum asset mix, adaptability to risk and affordability. In addition, given unique impact on generation of environmental compliance, the planning effort must be in concert with anticipated long-term requirements as established by the environmental compliance planning process.

B. KPCo/AEP SYSTEM RESOURCE PLANNING CONSIDERATIONS

B.1. General (807 KAR 5:058 Sec.8.5.b.)

The AEP System -East Zone is planned, constructed and operated as an integrated power system. However, each operating subsidiary is still responsible in the long run for providing adequate generating-capacity resources to supply its own requirements. Under the AEP Interconnection Agreement (which represents the "pool agreement" among the five generating AEP System – East Zone operating companies), each member of the pool is responsible for a proportionate share of the aggregate AEP- East Zone pool generating capacity. Each member must provide sufficient generating capacity to meet its own internal load requirements plus an adequate reserve margin. Whenever a member company's generating capability is insufficient to supply its demand, it draws upon the resources of the other AEP-East Zone companies in accordance with the provisions of the Interconnection Agreement. At other times that company may have generating capability in excess of its own needs, which is utilized as necessary to supply part of the load requirements of the other AEP- East Zone companies.

Thus, the evaluation of the adequacy and reliability of KPCo's generating capability to meet the current and projected power demands of its customers must be based on consideration of the total generating capability of the AEP-East Zone in relation to the aggregate AEP-East Zone load (taking into account contractual arrangements with other affiliated and nonaffiliated parties and the availability of power from other regional sources).

On October 1, 2004, AEP-East Zone joined the PJM Regional Transmission Organization (RTO). Exhibit 4-1 shows the geographical spread of PJM. As part of this RTO, KPCo's Big Sandy generating plant is centrally dispatched in conjunction with the plants of the other AEP-East Zone operating companies and the other units in the PJM RTO, based on offers made to PJM for each unit. This process of dispatching all of the RTO's generating units from one control center ensures operation of the system in the most economical manner.

Effective with its 2007/08 delivery year (June 1, 2007 through May 31, 2008), PJM instituted a new capacity-planning regime, called the Reliability Pricing Model (RPM). Its purpose is to develop a long-term price signal for capacity resources as well as load-serving entity (LSE) obligations that is intended to encourage the construction of new generating capacity in the region. The heart of the RPM is a series of capacity auctions, extending out four planning years, into which all generation that will serve load in PJM will be offered. The required reserve margin under RPM is determined by the intersection of the capacity-offer curve with an administratively-determined demand curve. In steady-state mode, the auction will be held 38 months before the beginning of the plan year, with subsequent auctions to trim up the capacity commitments as forecasts change. The reserve margin determined each year by PJM is intended to maintain a one day in ten year loss of load expectation, similar to the criterion used by AEP System – East Zone and KPCo for many years.

FERC has authorized and PJM has provided for an alternative to the capacity auction, called the Fixed Resource Requirement (FRR), which can be appropriate for vertically integrated utilities to use. Under the FRR, the reserve margin is not dependent upon the intersection of the offer curve and the administratively-set demand curve but is built directly upon the fixed PJM Installed Reserve Margin (IRM) requirement, as it was prior to the introduction of RPM. This alternative allows opting entities to meet their requirements with a lower capacity requirement than might have resulted under the auction model, and provides more cost certainty. AEP System – East Zone has elected to "opt-out" of the RPM (auction) and will be utilizing the FRR (self-planning) construct. That opt-out of the PJM capacity auction currently is effective through the 2012/13 delivery year, for which the auction was held in May 2009. Each subsequent year AEP System-East Zone will evaluate whether to continue to utilize FRR for an additional year or whether opting to participate in the RPM auction (for a minimum commitment of five-years) might provide more advantages.

B.2. Generation Reliability Criterion (807 KAR 5:058 Sec.8.5.d.)

As indicated, AEP System-East Zone is committed to the FRR alternative to the RPM of PJM through the 2012/2013 delivery year, and *it was assumed that this commitment would continue indefinitely.*

Although PJM will consider changes in the IRM, it was also assumed that this factor would remain constant at 16.2%, as currently set for the 2012/13 delivery year. For each delivery year, PJM determines the IRM requirement approximately 42 months before the June 1 start date. The IRM is based on studies that determine the capacity required to maintain a one-day-in-ten-year loss of load expectation, given historical unit availabilities and load shapes and assistance that may be expected from neighboring regions. For AEP System – East Zone as an FRR entity, the required reserve margin is also based on the coincidence of the AEP System – East Zone's peak with the RTO peak and the relationship of AEP- East Zone's historical Equivalent Forced Outage Rate-demand (EFORd) to that of the RTO as a whole.

It was assumed that PJM would continue to calculate an effective coincidence factor of AEP System – East Zone with the RTO peak of about 96%. This factor tends to reduce the AEP-East Zone reserve requirement from the 15% to 16 % range where the IRM has been in recent years to the 11% to 12% range.

It also was assumed that the underlying PJM EFORd used for 2012/13 (6.44%) would remain constant into the following years. On the other hand, it was assumed that AEP-East Zone unit EFORds would change through time. Existing unit EFORds were projected to change as unit improvements are made or as units near retirement. Also, the addition of new units and retirement of old units from the system changes the weighted average EFORd. With the exception delivery year 2010/11, which is heavily impacted by the current outage at the D. C. Cook Nuclear Plant (owned by the affiliated Indiana Michigan Power Company), AEP System – East Zone's EFORd is projected to improve from 8.41% in 2009/10 to 6.56% in 2018/19. This assumption tends to reduce the amount of new installed capacity needed to meet PJM requirements.

B.3. Environmental Compliance (807 KAR 5:058 Sec.8.5.f).

AEP System – East Zone and its operating companies (such as Kentucky Power) have historically developed compliance strategies to meet the requirements of the Clean Air Act (CAA) and its Amendments (CAAA) as each rule became known. In addition to the CAAA Title IV (Acid Rain Program) Phase I and II emission requirements for SO_2 and NO_X, these rules include the NO_X State Implementation Plan (SIP) Call, Clean Air Interstate Rule (CAIR), Clean Air Mercury Rule (CAMR), and Clean Air Visibility Rule (CAVR). Looking beyond existing CAAA rules, the electric utility industry, as a major producer of CO_2, will be significantly affected by any green house gas (GHG) legislation.

Compliance with Title IV SO_2 requirements involved continually evaluating alternative fuel strategies, exercising opportunities to purchase sulfur dioxide allowances, and retrofit of post-combustion technologies in order to lower the overall cost of compliance. For Title IV NO_X compliance, AEP's strategy included installing low-NO_X burner technologies on its Phase II NO_X units and using an averaging plan for its remaining generating units.

Beginning in May 2004, the AEP System was required to meet more stringent NO_X emission limitations during the May through September ozone season as part of the NO_X SIP Call. These requirements included Big Sandy Plant in Kentucky. The compliance plan for Big Sandy Plant to meet this requirement included installation of an overfire air burner modification and water injection system and boiler tubes overlay on Unit 1 and installation of a selective catalytic reduction (SCR) system on Unit 2. The latter installation also required upgrading the Unit 2 electrostatic precipitator. Similar NO_X reduction technologies were implemented at other units across the AEP System.

On January 30, 2004, the United States Environmental Protection Agency (USEPA) proposed the Interstate Air Quality Rule (IAQR), renamed as the CAIR that became effective on July 11, 2005. The CAIR is a two-phase program, which calls for significant reductions of NO_X and SO_2, beginning in 2009 and 2010, respectively, with Phase I implementation, followed by Phase II beginning in 2015. In response to legal appeals of the CAIR, the D.C. Circuit Court remanded the rule to EPA for further rulemaking. While EPA addresses the deficiencies identified by the Court, the compliance requirements of CAIR remain in effect. This includes NO_X reduction requirements beginning in 2009 and SO_2 reduction requirements in 2010. There is a great deal of uncertainty over what approach EPA will take to rewrite CAIR and its associated compliance requirements. For purposes of planning, the AEP-East Zone expects the CAIR program to be replaced with a more restrictive policy. While EPA is determining how to respond to the D.C. Circuit Court remand of the CAIR, the AEP System – East Zone has postulated a scenario in which SO_2 and NO_X emissions will be 10% below the CAIR Phase II limits (fully implemented by 2025) and exclude an allowance bank to meet emission targets.

On March 15, 2005 the USEPA issued the CAMR which became effective on July 18, 2005. On February 8, 2008, the D.C. Circuit Court vacated the CAMR, eliminating any compliance requirements for mercury until EPA develops a new rule. Federal action is anticipated and could become effective in 2014 when a command-and-control policy could require all coal units to install either a mercury-specific control technology such as ACI or FGD/SCR emissions control equipment that in combination also reduce mercury emissions. There is also a strong possibility that a plant-by-plant standard will replace a mercury trading system. If this is the case, a dispatch price would not be required, but additional controls such as baghouses or ACI would be needed. This could have an impact on proposed retirement dates of older, non-controlled units and ultimately the timing for new capacity.

On October 9, 2007, AEP entered into a consent decree with the U.S. Department of Justice to settle all complaints filed against AEP and its eastern affiliates under the New Source Review program of the Clean Air Act. The consent decree includes a schedule for installation of emissions control technology on certain AEP-East Zone units and annual caps on NO_X and SO_2 emissions from the AEP-East Zone fleet of coal units. With respect to generating facilities owned by Kentucky Power, it is bound by the decree to continuously operate low NO_X burners on Big Sandy Unit 1 beginning October 9, 2007 and an SCR on Big Sandy Unit 2 beginning January 1, 2009. Kentucky Power is also required to install and continuously operate FGD systems on Big Sandy Unit 2 by December 31, 2015. FGD and SCR systems will also be installed on Rockport Unit 1 by December 31, 2017, and on Rockport Unit 2 by December 31, 2019, in which KPCo has a 15% interest.

Looking to the future, GHG legislation has been proposed in recent sessions of Congress with the push towards federal climate change legislation continuing within the current 111th Congress. The Waxman-Markey "American Climate and Energy Security Act of 2009" was recently passed out of the House Energy and Commerce Committee. This bill will likely receive full consideration on the floor of the House of Representatives later this year. Virtually all of these bills employed "cap and trade" mechanisms (rather than carbon taxes) with declining CO_2 caps over time.

For the 2009 IRP cycle, the impact of CO_2/GHG legislation on AEP System – East Zone's long-term planning is essentially modeled as a simple CO_2 price that would impact fossil unit dispatch cost reflecting a scaled annual "cap" on the price of CO_2. AEP-East Zone's post-2010 strategy is to voluntarily reduce or offset an additional 5 million tons of CO_2 per year by purchasing offsets from projects such as forestry, reducing methane from agriculture, adding more renewable energy and improving the efficiency of its power plants. The original design basis of and subsequent improvements in its coal-fired power plants make them more efficient than the national average for coal plants. Between 2001 and 2007, this advantage helped avoid burning 16.2 million tons of coal, preventing the release of 39 million tons of CO_2.

In anticipation of GHG legislation and the need to develop and test facilities, the current plan reflects AEP System – East Zone's intention to install carbon capture and sequestration (CCS) equipment for a slipstream of Mountaineer Unit 1 effluent in 2010, a larger slipstream in 2014, and the entire unit in 2020.

The AEP System-East Zone Integrated Resource Plan (IRP) is based on current mandatory environmental compliance requirements which have a major influence on the consideration of supply-side resources for inclusion in the IRP because of their potential significant effects on both capital and operational costs. Further, on-going debate over CO_2/GHG emissions, particulate matter, and regional haze (CAVR) will likewise influence future capacity resource planning surrounding decisions to retrofit, modify operations, or retire/mothball generating assets. The current forecast of the existing AEP-East Zone generating fleet capability through the year 2023 reflects 425 MW in unit de-ratings associated with environmental retrofits. The net impact to existing units as a result of these deratings together with planned efficiency improvements is a 6 MW reduction in available capacity on the existing fleet (See Exhibit 4-7 for further details). The net impact for KPCo capacity is a reduction of 71 MW of capacity (See Exhibits 4-8 for further details).

C. PROCEDURE TO FORMULATE LONG-TERM PLAN (807 KAR 5:058 Sec.8.5.a.)

The following steps were involved to develop the resource plan presented in this report. These steps are as follows:

1. Develop the base-case load forecast.
2. Determine overall resource requirements.
3. Identify and screen DSM options
4. Identify and screen supply-side resource options
5. Integrate supply-side and demand-side options
   a. Optimize expanded DSM programs
   b. Develop optimal supply-side resource expansion plans with expanded DSM.
6. Analyze and Review.

A discussion of these steps follows.

C.1. Develop Base-Case Load Forecast

The development of the base-case load forecast is presented in Chapter 2. That initial forecast excludes adjustments for potential future (i.e., expanded) DSM programs.

C.2. Determine Overall Resource Requirements

The determination of overall resource requirements includes an evaluation of the adequacy of existing generating capability to meet the future forecasted load requirements.

C.2.a. Existing and Committed Generation Facilities (807 KAR 5:058 Sec.8.3.b.12.d., Sec. 8.3.d.)

KPCo's existing installed generating capability (as of June 1, 2009) is shown as part of Exhibit 4-2. KPCo's owned capacity consists of the 1,060 MW Big Sandy generating plant, located in Louisa, Kentucky. KPCo also has a unit power agreement with AEP Generating Company (AEG), an affiliate, to purchase 15% (currently a total of 393 MW) of capacity from the two units at the Rockport Plant, located in southern Indiana. Both KPCo Rockport unit power agreements run through December 7, 2022. For planning purposes, it has been assumed that the Rockport agreements extend indefinitely beyond that expiration date.

In comparison, as of June 1, 2009, the AEP System-East Zone's total generating capability was 28,726 MW reflecting the reduction for a 250 MW unit power sale currently in place with CP&L. The CP&L unit power sale expires at the end of 2009 at which time the AEP System-East Zone's total generating capability will become 28,976 MW. Such capacity is predominantly coal-fired generating units along with conventional hydroelectric, pumped storage, and nuclear capacity. The generating facilities which comprise this capability are listed in Exhibit 4-2.

Appalachian Power Company, an affiliate company, has purchased the unfinished Dresden combined cycle unit in Ohio, which is mentioned at the bottom of Exhibit 4-2. The estimated cost at completion of this unit is \$395 million (in 2013 dollars) or \$632 per kW of winter capacity.

Actual production cost and operating information for each of the AEP East Zone's generating units for the year 2008 are provided in Exhibit 4-3 and Exhibit 4-5 (the latter found in the Confidential Supplement to this report).

C.2.b. Retrofit or Life Optimization of Existing Facilities (807 KAR 5:058 Sec.8.2.a.)

Past experience has indicated that, with proper maintenance and operation, coal-fired units can expect to achieve operating lifetimes beyond the traditional nominal 35 to 40 years. Of course, the optimum achievable lifetime is highly unit-specific. Programs have been developed by AEP to attempt to achieve optimal operating lifetimes, and to do so as economically as possible. The work of component refurbishment or replacement is planned and carried out over a long period, so as to minimize total cost and the outage time required. The replacement of steam valves on Rockport Unit 1 (in 2017) and Unit 2 (in 2019) is expected to increase their efficiency so as to offset the impact of auxiliary loads associated with flue gas desulfurization systems (SO_2 scrubbers) that are to be installed at the same times. Ultimately, however, retirement of older units must be considered as units become less economic from efficiency, cost, and environmental standpoints.

The impact of any potential carbon related cap-and-trade regime will compound the deteriorating cost profile of some of the older, non-environmentally-controlled, higher heat-rate, coal-fired plants. Also, the consent decree that resolved the Company's federal New Source Review litigation imposed hard caps on emissions of SO_2 and NO_X and established specific dates to retire, retrofit, or repower identified coal units.

A financial analysis was performed and focused on gross margin exposure to various market commodity variables: market energy price and projected SO_2, NO_X and CO_2 allowance prices. The allowance prices were of particular importance given that most of the units' high, uncontrolled emission rates were anticipated to hinder future dispatchability. In addition, the introduction of CO_2 pricing would impact unit dispatch cost, beginning as early as 2015. Analyses were also performed using the *Strategist* model. The model was used to determine the relative impact on the overall AEP-East Zone's Cumulative Present Worth (CPW) of revenue requirements for each unit/unit-set if it were assumed retired in an early or a late year of the study period. These analyses resulted in the identification of Big Sandy Unit 1 as a potential candidate for retirement late in the fifteen-year planning horizon and a date past the winter peak of 2023 has been used in this plan.

C.2.c. Renewable Energy Plans (807 KAR 5:058 Sec.8.2.d.)

Renewable Portfolio Standards and goals have been enacted in over two-thirds of the states in the U.S. Adoption of further RPS at the state level or the enactment of Federal carbon limitations or RPS, will impose the need for adding more renewables and the potential expenditure of billions of dollars.

In early 2007, AEP System committed to the acquisition of energy from 1,000 MW (nameplate) of additional wind generation projects by the end of 2010 via long-term purchase power agreements as part of AEP's comprehensive strategy to address greenhouse gas emissions. In light of progress in meeting this commitment, the goal was expanded in early 2009 to 2,000 MW by the end of 2011. AEP operating unit Appalachian Power is already receiving energy from one wind project with nameplate rating of 75 MW and four additional contracts have been executed for APCo, CSP, and I&M for an additional 551 MW to be placed in service in 2009 and 2010.

As part of this commitment, the current plan reflects for KPCo a 50 MW (nameplate) wind project by year-end 2010 and a second 50 MW project by year-end 2012 to be provided through power purchase agreements.

Other renewable technologies were screened for cost-effectiveness, including biomass cofiring, in which a small amount (up to about 2% by heat) of biomass is fired in boilers along with coal, and biomass separate injection, in which larger amounts of biomass (up to 10% by heat) are injected separately into boilers. The current plan includes biomass cofiring on the two Rockport units by year-end 2013, upgraded to separate injection on one of the two units by year-end 2023. Separate injection also would be installed on Big Sandy Unit 2 by year-end 2015.

The renewable plan for the AEP-East Zone includes solar energy by the end of 2009, but this is driven by requirements in Ohio. KPCo's plan at this time does not include solar energy.

C.2.d. Demands, Capabilities and Reserve Margins Assuming No Other New Resources

Exhibit 4-7 provides a projection of the AEP-East Zone's peak demands, capabilities and reserve margins for the summer season from 2009 through 2024, assuming no other new resources are added to the system. The projected data reflect the base-case load forecast, committed sales to non-affiliated utilities, and the amount of AEP- East Zone's industrial interruptible load that can be interrupted at the time of the seasonal peak. The projected capabilities assume some existing generating units will be retired, as determined in the studies mentioned above.

The corresponding projections of KPCo's peak demands, capabilities and reserve margins are shown on Exhibit 4-8, but for the winter, which is KPCo's peak season.

C.3. Identify and Screen DSM Options

The identification and screening of DSM options is described in detail in Chapter 3 of this report.

C.4. Identify and Screen Supply-side Resource Options (807 KAR 5:058 Sec.8.2.d. and Sec. 8.5.e.)

C.4.a. Purchased Power (807 KAR 5:058 Sec.8.3.d. and Sec. 8.5.g.)

Information available at the time of preparation of this report suggests that capacity reserve margins–inclusive of current and anticipated merchant capacity–will decline to the point that new assets will have to be built within the next five years in the Reliability*First* Corporation (RFC) region that includes PJM and the AEP-East Zone.

The pressures for capacity become more pronounced as the impact of SO_2, NO_X, and mercury emission reduction requirements set forth by CAIR, and potential new mercury rules to replace the vacated CAMR rulemaking, are likely to negatively impact the utilization of existing coal-steam generating units, heightening the potential for regional capacity deficiencies by the 2017 timeframe. Any legislation to control CO_2 will further serve to depress regional capacity resources.

Due to these factors, capacity market liquidity cannot be assured significantly beyond the early portion of the next decade. Therefore, all capacity requirements identified in this process are represented in this plan as being met with <u>self-planned alternatives</u>. However, when the time comes to implement plans for new capacity, market or asset purchases that might substitute for the required type of planned capacity would certainly be evaluated.

The primary sources for identifying the existing and projected capacity are the Project Generation Queue schedules available from MISO and PJM RTO reports such as active summary posted on the PJM website. Also, the RFC report, "Long Term Resource Assessment 2008-2017," contains a list of the individual planned and proposed MISO and PJM projects based on the Queue schedules. These projects for the RFC report are listed in Appendix A of the report, which is available on the RFC website. It should be noted that this list includes many projects that will never come to fruition.

C.4.b. New Capacity Alternatives

AEP's New Technology Development organization is responsible for the tracking and monitoring of estimated cost and performance parameters for a wide array of generation technology alternatives. Utilizing access to industry collaboratives such as EPRI and EEI, AEP's association with architects and engineering firms and original equipment manufacturers as well its own experience and intelligence-gathering, this group continually monitors such supply-side trends. Exhibit 4-9 (see the Confidential Supplement to this report) offers a summary of the most recent technology cost and performance parameter data developed.

The various alternatives were divided into duty cycles (baseload, intermediate, or peaking) and within each duty cycle screening analysis was used to select a typical unit to be used for purposes of system economic modeling. The following specific supply alternatives were selected to represent capacity having various duty cycles:

- *Peaking capacity* was modeled as blocks of four GE-7FA Combustion Turbine units (winter rating of 171 MW x 4 = 684 MW; summer rating of 155.6 MW x 4 = 622 MW), available beginning in 2017.

- *Intermediate capacity* was modeled as single natural gas Combined Cycle (2 x 1 GE-7FB with duct firing platform) unit (rated 669 MW winter, 609 MW summer) available beginning in 2017.
- *Baseload capacity* burning eastern bituminous coals was modeled. The potential for future legislation limiting CO_2 emissions beginning in the 2020 timeframe was considered in selecting the solid fuel baseload capacity alternatives,. Two types of solid fuel alternatives were made available to the model:
  - ✓ Ultra Supercritical PC unit (rated 624 MW winter, 612 MW summer) where the unit received a chilled ammonia carbon capture and sequestration (CCS) retrofit in 2020 that would capture 90% of the unit's CO2 emissions. The addition of the CCS retrofit would reduce the unit's capacity to 530 MW winter and 520 MW summer. This alternative could be added by *Strategist* from 2017 through 2019. Under the scenario where CO2 prices did not exist, this unit without the CCS retrofit was available for selection beginning in 2017;
  - ✓ Ultra Supercritical PC unit with CCS equipment that would reduce 90% of the unit's carbon emissions installed during the unit's construction (rated 632 MW winter, 619 MW summer). This alternative could be added by *Strategist* beginning in 2020.

  In addition, beginning in the year 2020:

  - ✓ *Strategist* could select an 800 MW share of a 1,600 MW nuclear, Mitsubishi Heavy Industries (MHI) Advanced Pressurized Water Reactor (760 MW summer)

C.5. Integrate Supply-Side and Demand-Side Options

As described below in section E.1., the *Strategist* model, used to study the integration and optimization of various resource alternatives, requires projections of various external parameters that primarily are driven by market forces. The input variables to the forecasts of these parameters include forecasts of fuels, load, emissions, emission retrofits, construction costs for capital projects, and others. Each input variable is shaped by government-provided historical data, government forecasts, leading energy-industry consultancies, AEP-internal views and the output of industry-accepted modeling tools, which apply economic principles and dispatch simulation to model the relationships of utility supply, transmission and demand to forecast market prices. The refinement of analysis is continuous, but is immediately oriented toward emissions, renewables, volatile commodity prices and changing economic conditions.

C.5.a. Optimize Expanded DSM Programs

As described in Chapter 3, eighteen "blocks" of DSM (Energy Efficiency and DR) programs were developed and then evaluated in *Strategist*. The purpose of this screening was to minimize the problem size in the full *Strategist* optimization when all supply-side options were included. The DSM blocks were evaluated under several economic scenarios. The results of this screening analysis showed that 10 blocks of DSM were selected under all of the economic scenarios and resulted in a peak reduction of about 375 MW from EE and 600 MW from Commercial and Industrial DR by the year 2015.

C.5.b. Development of Supply-Side Resource Expansion with DSM (807 KAR 5:058 Sec.8.3.b.12.f.)

Beginning with the current generation resources, potential unit retirements, renewable resources, and screened DSM programs described above, the *Strategist* model was used to determine the final plan for traditional generating alternatives. This procedure was carried out under four future scenarios of commodity, emission, and market energy prices. Generally only the highest price scenario resulted in anything other than gas-fired capacity in an optimal plan. Several alternative plans in which nuclear or coal alternatives were identified in these studies.

Exhibits 4-10 and 4-11 show the projected summer and winter capacity, load, and reserve position of the AEP System-East Zone with expanded DSM and new capacity as determined from the current studies, for the years 2007 through 2024.

Exhibits 4-12 and 4-13 show KPCo's corresponding projected summer and winter peak demands, capabilities, and reserve margins for the same period, including expanded DSM and new capacity, after allocating the AEP-East Zone resource additions to the five operating companies. To allocate such resource additions equitably, they are generally assigned to the operating company with the lowest reserve margin.

Exhibit 4-14 provides projected annual energy requirements, energy resources and energy inputs by primary fuel type. Exhibit 4-4 provides projected variable production cost data and Exhibit 4-6 provides projected unit operating data. These exhibits can be found in the Confidential Supplement to this report. General inflation is assumed to be 2.11% per year (compound average growth rate).

C.6. Analysis and Review

The AEP System- East Zone integrated resource plan presented herein is expected to provide adequate reliability over the forecast period.

The long-term capacity schedule reported herein is simply a snapshot of the future at this time, based on current thinking relative to various parameters, each having its own degree of uncertainty. The expansion reflects, to a large extent, assumptions that are subject to change. As the future unfolds, and as parameter changes are recognized and updated, input information must be continually evaluated, and resource plans modified as appropriate.

Some key factors that can affect the timing of future capacity additions are the magnitude of future loads and capacity reserve requirements. The magnitude of the future load in any particular year is a function of load growth and DSM impacts. Capacity reserve requirements, as discussed above, could vary depending on the average system generating-unit availability of both AEP and PJM.

Exhibit 4-15 provides a comparison of the previously reported (1999) plan of five-company AEP System - East Zone and the current (2009) plan for the five-company AEP System-East Zone. The exhibit shows that for the 2009 plan, for KPCo, through the year 2019 (the end of the planning period covered by the old plan), a total of 377 MW (nameplate) of capacity is assumed to be allocated, net of capacity deratings and efficiency impacts on thermal units. In comparison, the 1999 plan shows a total of 400 MW for the corresponding period from 2010 through 2019.

D. OTHER CONSIDERATIONS AND ISSUES

D.1. Transmission System (807 KAR 5:058 Sec.5.4.)

The eastern Transmission System (AEP-East Zone), as shown in Exhibit 4-16 (see the Confidential Supplement to this report), consists of the transmission facilities of the seven eastern AEP operating companies. This portion of the transmission system is comprised of approximately 15,000 miles of circuitry operating at or above 100 kV. The AEP-East Zone includes over 2,100 miles of 765 kV overlaying 3,800 miles of 345 kV and over 8,800 miles of 138 kV circuitry. This expansive system allows AEP System – East Zone to economically and reliably deliver electric power to approximately 24,200 MW of customer demand connected to the eastern transmission system that takes transmission service under the PJM open access transmission tariff. Exhibit 4-17 (see the Confidential Supplement to this report) displays a map of KPCo's transmission system and the location of KPCo's generating plant, and Exhibit 4-18 provides a table of the AEP-East Zone interconnections in the Kentucky area.

The eastern Transmission System is the most integrated transmission system in the Eastern Interconnection and is directly connected to 19 neighboring transmission systems at 144 interconnection points, of which 118 are at or above 100 kV. These interconnections provide an electric pathway to facilitate access to off-system resources and serve as a delivery mechanism to adjacent companies. The entire eastern Transmission System is located within the RFC Regional Reliability Organization footprint. On October 1, 2004, AEP- East Zone joined the PJM Regional Transmission Organization, and now participates in the PJM markets.

Despite the robust nature of the eastern Transmission System, certain outages coupled with extreme weather conditions and/or power-transfer conditions can potentially stress the system beyond acceptable limits. The most significant transmission enhancement to the eastern AEP Transmission System over the last few years was completed in 2006. This was the construction of a 90-mile 765 kV transmission line from Wyoming Station in West Virginia to Jacksons Ferry Station in Virginia. In addition, EHV/138 kV transformer capacity has been increased at various stations across the eastern Transmission System.

There are three projects planned for the Kentucky Power Company transmission system in the next few years. The first of these projects, Coalton Area Network Improvement, will alleviate thermal overload and heavy loading conditions, improve reliability, and provide margin for future growth in the South Neal-Coalton-Bellefonte area by tapping the Chadwick-KES 138 kV circuit and installing a new 138/69 kV 200 MVA transformer at the Coalton station. This project is currently projected to be in service in 2012.

A second project, Thelma-Paintsville Area Project, will provide single contingency reliability to the Paintsville area by adding a 138/69 kV, 90 MVA transformer at Thelma Station and constructing 1.8 miles of 69 kV line from the West Paintsville Station to the Paintsville Station and converting the Thelma-Paintsville 46 kV line to 69 kV to close the 69 kV loop. This project is currently projected to be in service between 2012 and 2013.

The third project, Hazard Area Improvements Project, will provide single contingency reliability to the Hazard area subtransmission system and double contingency reliability to the area 138 kV system by providing another 138 kV source into the Hazard area of eastern Kentucky. This project is currently projected to be in service between 2013 and 2015.

D.2. Fuel Adequacy and Procurement

D.2.a. Coal

The generating units of the AEP-East Zone, which are predominantly coal-fired, are expected to have adequate fuel supplies to meet normal burn requirements in both the short-term and the long-term. KPCo and the other AEP-East Zone operating companies attempt to maintain in storage at each plant an adequate coal supply to meet normal burn requirements. However, in situations where coal supplies fall below prescribed minimum levels, the operating companies have developed programs to conserve coal supplies. These programs involve, on a progressive basis, limitations on sales of power and energy to neighboring utilities, appeals to customers for voluntary limitations of electric usage to essential needs, curtailment of sales to certain industrial customers, voltage reductions and, finally, mandatory reductions of usage of electricity. In the event of a potential severe coal shortage, the operating companies, including KPCo, will implement procedures for the orderly reduction of the consumption of electricity, in accordance with the AEP East/PJM and AEP West/SPP Emergency Operating Plan.

American Electric Power Service Corporation, acting as agent for each of the AEP-East Zone's generating companies, is responsible for the overall procurement and delivery of coal to all of the AEP-East Zone generating facilities. AEP obtains much of its total coal requirements under long-term arrangements, thus assuring the plants of a relatively stable and consistent supply of coal. The remaining coal requirements are normally satisfied by making short-term and spot-market purchases. Additional spot purchases may occasionally be necessitated by shortfalls in deliveries caused by force majeure and other unforeseeable or unexpected circumstances. Occasionally, spot purchases may also be made to test-burn any promising and potential new long-term sources of coal in order to determine their acceptability as a fuel source in a given power plant's generating units. This policy also provides some flexibility to adjust scheduled contract deliveries for short-term coal supply to accommodate changing demand, which may be more or less than anticipated when the long-term coal requirements were initially projected. During periods preceding the expiration of coal mining labor agreements, additional fuel is stockpiled at the power plants to assure adequate supplies in the event of prolonged actions.

The AEP-East Zone's fuel requirements vary from plant to plant, depending upon such factors as environmental restrictions and boiler design, as well as the demand for electricity. In 2008, coal consumption at the AEP-East Zone's operated plants aggregated to more than 30 million tons. Of this amount, KPCo's Big Sandy plant accounted for about 2.5 million tons. Historically, the coal supplies for the Big Sandy plant have primarily been provided by operations located in Kentucky.

D.2.b. Natural Gas

It is anticipated that the site(s) for any new gas-fired capacity that might be added to the AEP System-East Zone would be determined by analyzing both the transmission infrastructure capabilities and the availability/proximity of mainline gas transmission pipelines. These pipelines would act as transporters for natural gas which would be purchased from third parties. Through the integrated natural gas transmission network, gas could be sourced from all major production areas, including Appalachia, Canada, Louisiana, Oklahoma, and Offshore-Gulf of Mexico, and Texas. It is anticipated that distillate oil would be the backup fuel for any new gas-fired capacity; hence, on-site oil storage would be considered for these potential unit sites.

E. RESOURCE PLANNING MODELS (807 KAR 5:058 Sec.8.5.a. and Sec.8.5.c.)

Information which describes the planning models (apart from the load forecasting models) utilized by AEP System – East Zone in developing its integrated resource plans is provided below.

E.1. *STRATEGIST*

The *Strategist* optimization model served as the empirical calculation basis from which capacity portfolios were examined and recommendations were made. As its objective function, *Strategist* determines the regulatory least-cost resource mix for the generation ("G") system being assessed. The solution is bounded by user-defined set of resource technologies, commodity pricing, and prescribed sets of constraints. *Strategist* incorporates a variety of expansion planning assumptions including:

- Resource alternative characteristics (e.g., capital cost, construction period, project life).
- Operating parameters of existing and new units.
- Unit dispositions (retirement/mothballing).
- Delivered fuel prices.
- Prices of external market energy and capacity as well as emission allowances.
- Reliability constraints (in this study, minimum reserve margin targets).
- Emission limits and environmental compliance options.

Strategist includes and recognizes in its revenue requirement calculation:

- Fixed costs of capacity additions, i.e. carrying charges on capacity and associated transmission (based on a weighted average AEP System cost of capital), and fixed O&M;
- Fixed costs of any capacity purchases;
- Installation and administrative costs of DSM alternatives;
- Variable costs associated with the <u>entire</u> fleet of new and existing generating units (developed using its probabilistic unit dispatch optimization engine). This includes fuel, purchased energy, market replacement cost of emission allowances, and variable O&M costs; and
- Market revenues from external energy transactions (i.e. Off-System Sales) are netted against these costs under this ratemaking/revenue requirement format.

Within *Strategist* the least-cost expansion plan is formulated from potentially <u>thousands</u> of resource alternative combinations created by the module's chronological dynamic programming algorithm. On an annual basis, each capacity resource alternative combination that satisfies the defined constraints is considered to be a "feasible state" and is saved by the program for consideration in following years. As the years progress, the previous years' feasible states are used as starting points for the addition of more resources that can be used to meet the current year's minimum reserve requirement.

E.2. PROMOD

PROMOD is a computer program that simulates how an electric utility operates and dispatches its generating units. Inputs to PROMOD include: forecasted loads and load shapes; forecasted price and availability of fuel; prices and quantities for capacity and energy purchases and sales; capacities, availabilities and heat rates for generating units; and data that describe rules for committing and dispatching generating units. PROMOD's outputs include: generation by unit; fuel consumption and fuel expense by unit and by fuel contract; and purchases and sales of energy and their associated costs and revenues.

PROMOD simulates the operation of an electric utility system by economically dispatching the utility's generating resources subject to various operating constraints such as fuel supply limitations, the need to maintain operating reserves, minimum operating and shutdown intervals for generating units and power transfer constraints. PROMOD explicitly recognizes the effect of generating unit forced outages and their impact on system operating costs.

E.3. DR/EE Screening

For a description of DR/EE screening, see Chapter 3, Section D. In addition to the screening described there, on the AEP-East Zone level screening was carried out using the *Strategist* model described above.

F. 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 recommendations pertaining to Supply-Side Resource Assessment are restated from the Staff report and addressed below:

1. **Kentucky Power/AEP should continue to expand the list of options screened.**

   Please see Exhibit 4-9 (in the Confidential Supplement to this filing) for a list and primary characteristics of capacity options screened. The list has been expanded considerably and new options will be added as they become available.

2. **Kentucky Power/AEP should screen purchased power in the same manner as other supply-side alternatives.**

   As stated in Section C.4.a. of this chapter, above, KPCo/AEP does not believe that at the present, for long-term planning purposes, markets should be relied upon to provide major supply-side resources. However, in any implementation plan, the potential to purchase capacity or facilities on the market would be given equal consideration with the potential to own capacity. Market participation is a legitimate option but carries risks that must be managed.

3. **Kentucky Power/AEP should fully consider the potential effects of environmental considerations, especially NO_X requirements and CO_2 concerns, in its supply-side analysis and should thoroughly document its analysis of these issues.**

   AEP's environmental compliance is discussed in Section B.3. of this chapter and is reflected in the resulting plan. Environmental compliance plans are becoming more complicated as the rules of the road change. Greenhouse gas legislation in particular could have major impacts and could change AEP's perspective on additional investments in environmental retrofit projects.

4. **While the methodology is sound, the results are limited by the shortcomings in Kentucky Power/AEP's supply-side analysis. Staff recommends that Kentucky Power/AEP follow the same integration methodology in its next IRP, but with a broader view of supply-side options including potential environmental costs.**

   A wide array of supply options was evaluated in this planning cycle. Please see Sections C. and E.1. of this chapter.

G. KENTUCKY COMMISSION ORDER – ADM CASE NO. 387 ISSUE ADDRESSED

In the Commission's order in ADM Case No. 387 page 93 dated December 20, 2001 required all utilities to conduct a renewed analysis of appropriate reserve margins to be used for planning purposes and shall include that analysis in their next IRP filed pursuant to 807 KAR 5:058.

See the discussion of AEP reserve requirements as part of the PJM RTO in Sections B.1. and B.2. of this chapter. Each year PJM carries out a very thorough and lengthy study of reserve margin requirements. Their latest report, the 114-page "2008 PJM Reserve Requirement Study," can be found on their website at http://www.pjm.com/~/media/documents/reports/20081015-item-04-2008-pjm-reserve-requirement-study.ashx

H. CHAPTER 4 EXHIBITS

Exhibit 4-1

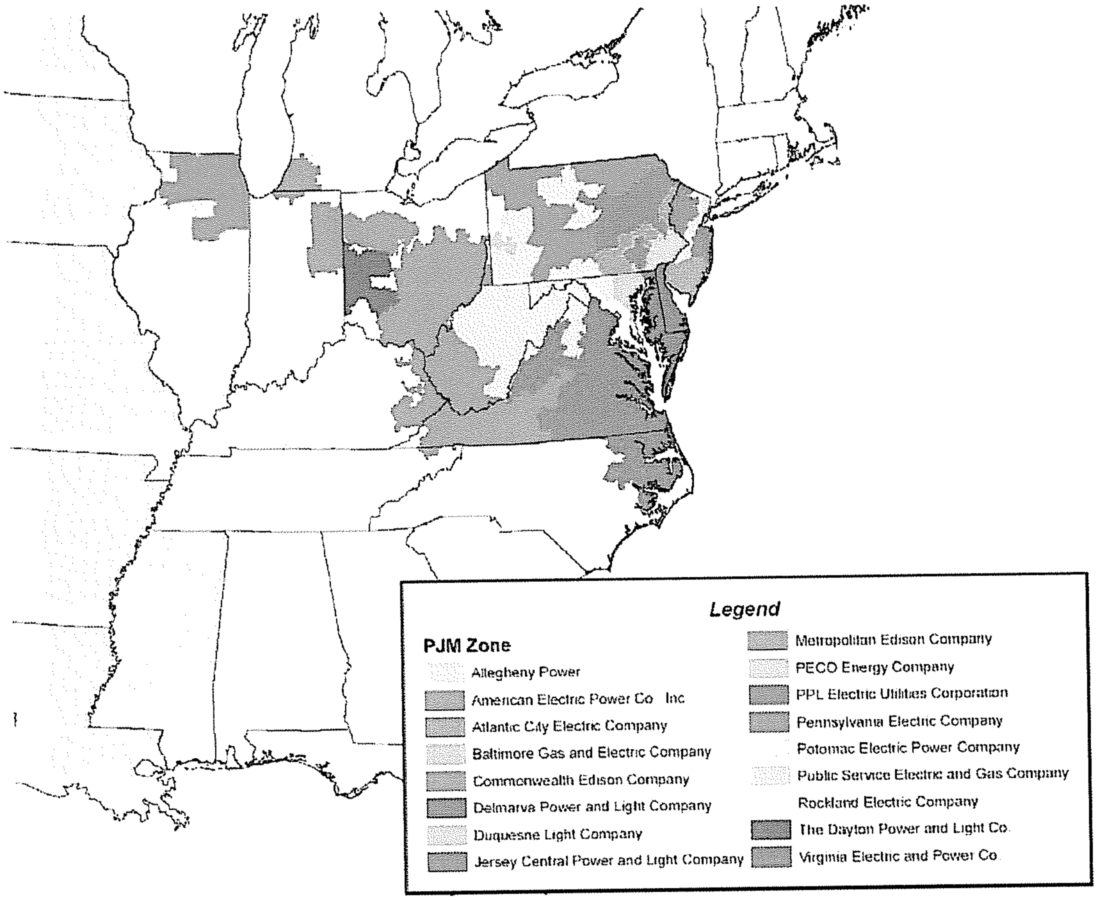


Exhibit 4-2 (page 1) (807 KAR 5:058 Sec.8.3.b.1-10.)

AEP System - East Zone
(Including Buckeye Power Capacity per Operating Agreement)
Existing Generation Capacity as of June 1, 2009

Plant Name	Location	Unit No.	In-Service Date		AEP Own/ Contract	Mode of Operation	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	Plant Fuel Storage Capacity (Tons000)	SCR Installation Year	FGD Installation Year	Super Critical	Age
						APCo								
Amos	St. Albans, WV	1	1971		O	Base	800	800	Coal	1.750	2005	2013	Y	38
Amos	–	2	1972		O	Base	800	800	Coal	–	2004	2012	Y	37
Amos	–	3	1973		O	Base	433	428	Coal	–	2004	2009	Y	36
Clinch River	Carbo, VA	1	1958		O	Base	235	230	Coal	500	–	–	N	51
Clinch River	–	2	1958		O	Base	235	230	Coal	–	–	–	N	51
Clinch River	–	3	1961		O	Base	235	230	Coal	–	–	–	N	48
Glen Lyn	Glen Lyn, VA	5	1944		O	Base	95	90	Coal	160	–	–	N	65
Glen Lyn	–	6	1957		O	Base	240	235	Coal	–	–	–	N	52
Kanawha River	Glasgow, WV	1	1953		O	Base	200	200	Coal	300	–	–	N	56
Kanawha River	–	2	1953		O	Base	200	200	Coal	–	–	–	N	56
Mountaineer	New Haven, WV	1	1980		O	Base	1,320	1,310	Coal	2,100	2004	2007	Y	29
Sporn	Graham Station, WV	1	1950		O	Base	150	145	Coal	750	–	–	N	59
Sporn	–	3	1951		O	Base	150	145	Coal	–	–	–	N	58
APCo Coal							5,093	5,043						41
Ceredo	Ceredo, WV	1-6	2001	(a)	O	Peaking	516	450	Gas (CT)	–	–	–	N	8
APCo Gas							516	450						8
APCo Hydro	Various		Various		O	Base	142	51	Hydro	–	–	–		
Summersville	Summersville, WV	1-2	2001		C	Base	27	7	Hydro	–	–	–		8
APCo Hydro				(b)			169	59						8
Smith Mountain	Penhook, VA	1	1965		O	Peaking	66	66	PSH	–	–	–	–	44
Smith Mountain	–	2	1965		O	Peaking	174	174	PSH	–	–	–	–	44
Smith Mountain	–	3	1980		O	Peaking	105	105	PSH	–	–	–	–	29
Smith Mountain	–	4	1966		O	Peaking	174	174	PSH	–	–	–	–	43
Smith Mountain	–	5	1966		O	Peaking	66	66	PSH	–	–	–	–	43
APCo Pumped Storage							585	585						41
APCo Wind			Various	(c)	C	Wind Project	26	26	Wind		–	–	–	
Total APCo							6,389	6,163						
						Cardinal-Buckeye								
Cardinal	Brilliant, OH	2	1967		C	Base	580	580	Coal	1,000	2004	2008	Y	42
Cardinal	–	3	1977		C	Base	630	630	Coal	–	2004	2012	Y	32
Buckeye Coal							1,210	1,210						37
Robert Mone	Convoy, OH	1-3	2001	(d)	C	Peaking	145	55	Gas (CT)	–	–	–	–	8
Buckeye Gas							145	55						8
Total Buckeye							1,355	1,265						
						CSP								
Beckjord	New Richmond, OH	6	1969		O	Base	52	52	Coal	–	–	–	N	40
Conesville	Conesville, OH	3	1962		O	Base	165	165	Coal	1.100	–	–	N	47
Conesville	–	4	1973		O	Base	337	337	Coal	–	2009	2009	Y	36
Conesville	–	5	1976		O	Base	395	395	Coal	–	2015	1976	N	33
Conesville	–	6	1978		O	Base	395	395	Coal	–	2015	1978	N	31
Picway	Lockbourne, OH	5	1955		O	Base	100	95	Coal	250	–	–	N	54
Stuart	–	1	1971		O	Base	151	151	Coal	–	2004	2008	Y	38
Stuart	–	2	1970		O	Base	151	151	Coal	–	2004	2008	Y	39
Stuart	–	3	1972		O	Base	151	151	Coal	–	2004	2008	Y	37
Stuart	–	4	1974		O	Base	151	151	Coal	–	2004	2008	Y	35
Zimmer	Moscow, OH	1	1991		O	Base	330	330	Coal	–	2004	1991	Y	18
CSP Coal							2,378	2,373						34
Waterford	Waterford, OH	1-6	2002	(a)	O	Intermediate/Pkg (CC)	850	810	Gas (CC)	–	2002	–	N	7
Darby	Darby, OH	1-6	2002	(e)	O	Peaking (CT)	507	435	Gas (CT)	–	2002	–	N	7
Lawrenceburg	Lawrenceburg, IN	1-6	2004	(e)	O	Intermediate/Pkg (CC)	1.186	1,120	Gas (CC)	–	–	–	N	5
Stuart Diesel	Aberdeen, OH	1-4	1969		O	Peaking (Diesel)	3	3	Oil (Diesel)	–	–	–	N	40
CSP Gas/Oil							2,546	2,368						6
CSP Wind			Various	(c)	C	Wind Project	0	0	Wind		–	–	–	
Total CSP							4,924	4,741						

(a) Acquired in 2005
(b) Hydro capacity is rated at expected annual average output
(c) The capacity of the Wind Energy Projects are listed at the preliminary PJM credit, 13% of the nameplate capacity
(d) The listed Mone capacity is the net impact of the various contracts with Buckeye Power
(e) Acquired in 2007 by AEP Generating Co, CSP receives capacity and energy via agreement

Exhibit 4-2 (page 2) (807 KAR 5:058 Sec.8.3.b.1-10.)

AEP System - East Zone
(Including Buckeye Power Capacity per Operating Agreement)
Existing Generation Capacity as of June 1, 2009

Plant Name	Location	Unit No.	In-Service Date	AEP Own/ Contract	Mode of Operation	Winter Capability (MW)	Summer Capability (MW)	Fuel Type	Plant Fuel Storage Capacity (Tons000)	SCR Installation Year	FGD Installation Year	Super Critical	Age
					I&M								
Rockport	Rockport, IN	1	1984	O	Base	1,122	1,114	Coal	2,500	2017	2017	Y	25
Rockport	–	2	1989	C	Base	1,105	1,105	Coal	–	2019	2019	Y	20
Tanners Creek	Lawrenceburg, IN	1	1951	O	Base	145	145	Coal	400	–	–	N	58
Tanners Creek	–	2	1952	O	Base	145	145	Coal	–	–	–	N	57
Tanners Creek	–	3	1954	O	Base	205	195	Coal	–	–	–	N	55
Tanners Creek	–	4	1964	O	Base	500	500	Coal	–	–	–	Y	45
I&M Coal						3,222	3,204						31
I&M Hydro				(b)	Base	15	11	Hydro		–	–	–	
Cook Nuclear	Bridgman, MI	1	1975	O	Base	1,084	1,007	Nuclear	–	–	–	–	34
Cook Nuclear	–	2	1978	O	Base	1,107	1,057	Nuclear	–	–	–	–	31
I&M Nuclear						2,191	2,064						32
I&M Wind			Various	(c) C	Wind Project	13	13	Wind		–	–	–	
Total I&M						5,441	5,252						
					KPCo								
Big Sandy	Louisa, KY	1	1963	O	Base	260	260	Coal	1,750	–	–	N	46
Big Sandy	–	2	1969	O	Base	800	800	Coal	–	2004	2015	Y	40
Rockport	Rockport, IN	1	1984	O	Base	198	197	Coal	–	2017	2017	Y	25
Rockport	–	2	1989	C	Base	195	195	Coal	–	2019	2019	Y	20
KPCo Coal						1,453	1,452						36
Total KPCo						1,453	1,452						36
					OPCo								
Amos	St. Albans, WV	3	1973	O	Base	867	857	Coal	–	2004	2009	Y	36
Cardinal	Brilliant, OH	1	1967	O	Base	580	580	Coal	–	2004	2008	Y	42
Gavin	Cheshire, OH	1	1974	O	Base	1,320	1,315	Coal	2,700	2004	1994	Y	35
Gavin	–	2	1975	O	Base	1,320	1,315	Coal	–	2004	1994	Y	34
Kammer	Captina, WV	1	1958	O	Base	210	200	Coal	1,050	–	–	N	51
Kammer	–	2	1958	O	Base	210	200	Coal	–	–	–	N	51
Kammer	–	3	1959	O	Base	210	200	Coal	–	–	–	N	50
Mitchell	Captina, WV	1	1971	O	Base	770	754	Coal	1,650	2007	2007	Y	38
Mitchell	–	2	1971	O	Base	790	790	Coal	–	2007	2007	Y	38
Muskingum River	Beverly, OH	1	1953	O	Base	205	190	Coal	1,300	–	–	N	56
Muskingum River	–	2	1954	O	Base	205	190	Coal	–	–	–	N	55
Muskingum River	–	3	1957	O	Base	215	205	Coal	–	–	–	N	52
Muskingum River	–	4	1958	O	Base	215	205	Coal	–	–	–	N	51
Muskingum River	–	5	1968	O	Base	600	600	Coal	–	2005	2015	Y	41
Sporn	Graham Station, WV	2	1950	O	Base	150	145	Coal	–	–	–	N	59
Sporn	–	4	1952	O	Base	150	145	Coal	–	–	–	N	57
Sporn	–	5	1960	O	Base	450	440	Coal	–	–	–	Y	49
OPCo Coal						8,467	8,331						41
OPCo Hydro			1983	(b) O	Base	25.5	20.4	Hydro		–	–	–	26
OPCo Wind			Various	(c) C	Wind Project	0.0	0.0	Wind		–	–	–	
Total OPCo						8,492	8,361						

(b) Hydro capacity is rated at expected annual average output.
(c) The capacity of the Wind Energy Projects are listed at the preliminary PJM credit. 13% of the nameplate capacity

Exhibit 4-3 (page 1) (807 KAR 5:058 Sec.8.3.b.12.c and e.)

AEP SYSTEM - EAST ZONE STEAM GENERATING-CAPACITY COST INFORMATION 2008					
	PLANT COST DATA				
Plant Name	Average Fuel Cost (¢/MBtu)	Non-Fuel Variable O&M ($000)	Fixed O&M ($000)	Average Variable Production Cost (¢/kWh)	Average Total Production Cost (¢/kWh)
Amos	253.95	24,555	74,886	2.86	3.17
W.C. Beckjord	42.42	1,346	2,087	1.04	2.85
Big Sandy	296.63	12,317	28,100	3.12	3.53
Cardinal (OPCo)	228.44	9,339	23,969	2.58	3.04
Clinch	322.49	5,745	14,674	3.45	3.76
Conesville	200.17	15,733	51,253	2.59	3.02
Cook	N/A	59,796	114,598	1.07	1.86
Gavin	178.5	17,696	169,611	2.49	2.66
Glen Lyn	351.27	3,390	10,229	4.37	4.86
Kammer	309.84	9,976	17,287	3.53	4.17
Kanawha	271.86	4,283	9,551	2.96	3.31
Mitchell	127.55	9,851	32,909	1.55	1.74
Mountaineer	250.55	14,449	36,082	2.65	2.94
Muskingum Rv.	217.28	14,243	36,760	2.45	2.76
Picway	269.41	1,481	4,703	4.46	5.35
Rockport	226.6	10,912	168,037	3.01	3.12
Sporn	275.26	11,499	25,196	3.18	3.65
Stuart	214.12	7,667	16,220	2.29	2.67
Tanners	286.39	12,430	27,298	3.34	3.87
Zimmer	166.97	3,964	11,796	2.13	2.43

Exhibit 4-3 (page 2) (807 KAR 5:058 Sec.8.3.b.12.c and e.)

AEP SYSTEM - EAST ZONE GAS-FIRED GENERATING-CAPACITY COST INFORMATION 2008					
	PLANT COST DATA				
Plant Name	Average Fuel Cost (¢/MBtu)	Non-Fuel Variable O&M ($000)	Fixed O&M ($000)	Average Variable Production Cost (¢/kWh)	Average Total Production Cost (¢/kWh)
Ceredo	1,001.29	634	1,166	13.10	15.43
Darby	N/A	N/A	N/A	N/A	N/A
Lawrenceburg	N/A	N/A	N/A	N/A	N/A
Waterford	1,114.95	1,303	6,670	10.87	11.81

Confidential Exhibit 4-4 (page 1) (807 KAR 5:058 Sec.8.3.b.12.c.)
See Confidential Exhibit 4-4, the "AEP System-East Zone, Projected Average Variable Production Costs (2009-2020)" (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Average Fuel Costs (¢/MMBtu)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Amos 1												
Amos 2												
Amos 3												
W.C. Beckjord 6												
Big Sandy 1												
Big Sandy 2												
Cardinal 1												
Clinch River 1												
Clinch River 2												
Clinch River 3												
Conesville 3												
Conesville 4												
Conesville 5												
Conesville 6												
D. C. Cook 1												
D. C. Cook 2												
Gavin 1												
Gavin 2												
Glen Lyn 5												
Glen Lyn 6												
Kammer 1												
Kammer 2												
Kammer 3												
Kanawha River 1												
Kanawha River 2												
Mitchell 1												
Mitchell 2												
Mountaineer 1												
Muskingum River 1												
Muskingum River 2												
Muskingum River 3												
Muskingum River 4												
Muskingum River 5												
Picway 5												
Rockport 1												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-4 (page 2) (807 KAR 5:058 Sec.8.3.b.12.c.)
See Confidential Exhibit 4-4, the "AEP System-East Zone, Projected Average Variable Production Costs (2009-2020)" (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Average Fuel Costs (¢/MMBtu)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rockport 2												
Philip Sporn 1												
Philip Sporn 2												
Philip Sporn 3												
Philip Sporn 4												
Philip Sporn 5												
Stuart 1												
Stuart 2												
Stuart 3												
Stuart 4												
Tanners Creek 1												
Tanners Creek 2												
Tanners Creek 3												
Tanners Creek 4												
Zimmer 1												
Ceredo 1												
Ceredo 2												
Ceredo 3												
Ceredo 4												
Ceredo 5												
Ceredo 6												
Darby 1												
Darby 2												
Darby 3												
Darby 4												
Darby 5												
Darby 6												
Lawrenceburg 1												
Lawrenceburg 2												
Waterford 1												
New CT 1												
New CT 2												
New CT 3												
New CT 4												
Dresden												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-4 (page 3) (807 KAR 5:058 Sec.8.3.b.12.g.)

See Confidential Exhibit 4-4, the "AEP System-East Zone, Projected Average Variable Production Costs (2009-2020)" (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Average Variable Production Costs (¢/kWh)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Amos 1												
Amos 2												
Amos 3												
W.C. Beckjord 6												
Big Sandy 1												
Big Sandy 2												
Cardinal 1												
Clinch River 1												
Clinch River 2												
Clinch River 3												
Conesville 3												
Conesville 4												
Conesville 5												
Conesville 6												
D. C. Cook 1												
D. C. Cook 2												
Gavin 1												
Gavin 2												
Glen Lyn 5												
Glen Lyn 6												
Kammer 1												
Kammer 2												
Kammer 3												
Kanawha River 1												
Kanawha River 2												
Mitchell 1												
Mitchell 2												
Mountaineer 1												
Muskingum River 1												
Muskingum River 2												
Muskingum River 3												
Muskingum River 4												
Muskingum River 5												
Picway 5												
Rockport 1												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-4 (page 4) (807 KAR 5:058 Sec.8.3.b.12.g.)
See Confidential Exhibit 4-4, the "AEP System-East Zone, Projected Average Variable Production Costs (2009-2020)" (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Average Variable Production Costs (¢/kWh)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rockport 2												
Philip Sporn 1												
Philip Sporn 2												
Philip Sporn 3												
Philip Sporn 4												
Philip Sporn 5												
Stuart 1												
Stuart 2												
Stuart 3												
Stuart 4												
Tanners Creek 1												
Tanners Creek 2												
Tanners Creek 3												
Tanners Creek 4												
Zimmer 1												
Ceredo 1												
Ceredo 2												
Ceredo 3												
Ceredo 4												
Ceredo 5												
Ceredo 6												
Darby 1												
Darby 2												
Darby 3												
Darby 4												
Darby 5												
Darby 6												
Lawrenceburg 1												
Lawrenceburg 2												
Waterford 1												
New CT 1												
New CT 2												
New CT 3												
New CT 4												
Dresden												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-4 (page 5) (807 KAR 5:058 Sec.8.3.b.12.e.)
See Confidential Exhibit 4-4, the "AEP System-East Zone, Projected Average Variable Production Costs (2009-2020)" (6 pages) provided in the Confidential Supplement to this filing.

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AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Non-Fuel Variable O&M ($000)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Amos 1												
Amos 2												
Amos 3												
W.C. Beckjord 6												
Big Sandy 1												
Big Sandy 2												
Cardinal 1												
Clinch River 1												
Clinch River 2												
Clinch River 3												
Conesville 3												
Conesville 4												
Conesville 5												
Conesville 6												
D. C. Cook 1												
D. C. Cook 2												
Gavin 1												
Gavin 2												
Glen Lyn 5												
Glen Lyn 6												
Kammer 1												
Kammer 2												
Kammer 3												
Kanawha River 1												
Kanawha River 2												
Mitchell 1												
Mitchell 2												
Mountaineer 1												
Muskingum River 1												
Muskingum River 2												
Muskingum River 3												
Muskingum River 4												
Muskingum River 5												
Picway 5												
Rockport 1												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-4 (page 6) (807 KAR 5:058 Sec.8.3.b.12.e.)
See Confidential Exhibit 4-4, the "AEP System-East Zone, Projected Average Variable Production Costs (2009-2020)" (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Non-Fuel Variable O&M ($000)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rockport 2												
Philip Sporn 1												
Philip Sporn 2												
Philip Sporn 3												
Philip Sporn 4												
Philip Sporn 5												
Stuart 1												
Stuart 2												
Stuart 3												
Stuart 4												
Tanners Creek 1												
Tanners Creek 2												
Tanners Creek 3												
Tanners Creek 4												
Zimmer 1												
Ceredo 1												
Ceredo 2												
Ceredo 3												
Ceredo 4												
Ceredo 5												
Ceredo 6												
Darby 1												
Darby 2												
Darby 3												
Darby 4												
Darby 5												
Darby 6												
Lawrenceburg 1												
Lawrenceburg 2												
Waterford 1												
New CT 1												
New CT 2												
New CT 3												
New CT 4												
Dresden												

* The 2009 projection reflects data for June through December

Exhibit 4-5 (page 1) (807 KAR 5:058 Sec.8.3.b.12.a. and b.)

AEP SYSTEM - EAST ZONE
STEAM GENERATING-CAPACITY OPERATING INFORMATION
2008

	UNIT OPERATING DATA			
Plant Name	Unit Number	Capacity Factor (%)	Equivalent Availability Factor (%)	Average Heat Rate (Btu/kWh)
Amos	1	84.1	91.9	9,731
	2	70.9	79.2	9,821
	3	46.1	49.8	10,054
W.C. Beckjord	6	31.7	39.5	10,198
Big Sandy	1	55.0	62.5	9,903
	2	67.8	77.1	9,317
Cardinal	1	62.4	68.3	9,248
Clinch	1	53.3	72.9	9,958
	2	60.0	82.7	10,135
	3	62.6	83.4	9,502
Conesville	3	55.3	89.6	10,952
	4	54.8	67.6	10,105
	5	83.9	84.7	10,359
	6	66.0	67.6	10,305
Cook	1	59.2	58.6	10,656
	2	96.6	96.6	10,825
Gavin	1	90.7	93.4	9,848
	2	91.5	92.7	9,800
Glen Lyn	5	33.6	73.7	13,274
	6	53.3	73.0	9,938
Kammer	1	55.4	77.7	10,439
	2	57.2	87.1	10,797
	3	56.3	75.8	10,382
Kanawha	1	68.0	87.3	9,942
	2	72.5	89.7	10,054
Mitchell	1	71.2	76.0	10,402
	2	83.9	90.4	10,118
Mountaineer	1	84.9	88.1	9,607
Muskingum Rv.	1	67.2	84.1	10,485
	2	65.8	84.9	10,526
	3	64.9	81.8	10,005
	4	56.0	72.0	9,974
	5	86.6	91.4	9,593
Picway	5	17.5	81.8	12,072
Rockport	1	89.4	96.6	9,600
	2	83.7	91.2	9,758
Sporn	1	57.2	78.8	10,828
	2	56.3	84.0	10,269
	3	66.7	86.7	10,184
	4	56.1	83.2	10,382
	5	46.3	71.5	10,110
Stuart	1	75.8	79.8	9,465
	2	79.9	83.8	9,659
	3	76.7	81.0	9,543
	4	70.5	74.4	9,738
Tanners	1	59.2	88.3	10,547
	2	65.6	90.2	10,480
	3	57.7	77.3	10,484
	4	46.9	53.6	10,011
Zimmer	4	90.5	92.0	10,466

Exhibit 4-5 (page 2) (807 KAR 5:058 Sec.8.3.b.12.a. and b.)

AEP SYSTEM - EAST ZONE
GAS-FIRED GENERATING-CAPACITY OPERATING INFORMATION
2008

Plant Name	UNIT OPERATING DATA			
	Unit Number	Capacity Factor (%)	Equivalent Availability Factor (%)	Average Heat Rate (Btu/kWh)
Ceredo	1	1.26	93.1	12,129
	2	1.32	93.0	12,134
	3	1.16	92.3	12,121
	4	1.15	92.2	12,096
	5	1.15	92.5	12,069
	6	1.14	92.5	12,073
Darby	1	0.66	90.4	12,759
	2	0.66	90.3	12,787
	3	0.48	88.1	12,854
	4	0.64	89.7	12,816
	5	0.48	87.2	11,440
	6	0.53	89.8	11,622
Lawrenceburg	1A	7.29	84.3	12,287
	1B	7.77	86.2	12,192
	1S	5.94	87.3	–
	2A	6.80	78.7	11,932
	2B	7.70	87.6	12,000
	2S	5.75	85.2	–
Waterford	CT1	3.87	92.4	13,150
	CT2	4.30	91.7	13,182
	CT3	3.49	92.2	13,319
	ST4	3.47	94.0	–

Confidential Exhibit 4-6 (page 1) (807 KAR 5:058 Sec.8.3.b.12.a.)
See Confidential Exhibit 4-6, AEP System-East Zone, Projected Operating Information (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Capacity Factors (%)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Amos 1												
Amos 2												
Amos 3												
W.C. Beckjord 6												
Big Sandy 1												
Big Sandy 2												
Cardinal 1												
Clinch River 1												
Clinch River 2												
Clinch River 3												
Conesville 3												
Conesville 4												
Conesville 5												
Conesville 6												
D. C. Cook 1												
D. C. Cook 2												
Gavin 1												
Gavin 2												
Glen Lyn 5												
Glen Lyn 6												
Kammer 1												
Kammer 2												
Kammer 3												
Kanawha River 1												
Kanawha River 2												
Mitchell 1												
Mitchell 2												
Mountaineer 1												
Muskingum River 1												
Muskingum River 2												
Muskingum River 3												
Muskingum River 4												
Muskingum River 5												
Picway 5												
Rockport 1												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-6 (page 2) (807 KAR 5:058 Sec.8.3.b.12.a.)
See Confidential Exhibit 4-6, AEP System-East Zone, Projected Operating Information (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Capacity Factors (%)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rockport 2												
Philip Sporn 1												
Philip Sporn 2												
Philip Sporn 3												
Philip Sporn 4												
Philip Sporn 5												
Stuart 1												
Stuart 2												
Stuart 3												
Stuart 4												
Tanners Creek 1												
Tanners Creek 2												
Tanners Creek 3												
Tanners Creek 4												
Zimmer 1												
Ceredo 1												
Ceredo 2												
Ceredo 3												
Ceredo 4												
Ceredo 5												
Ceredo 6												
Darby 1												
Darby 2												
Darby 3												
Darby 4												
Darby 5												
Darby 6												
Lawrenceburg 1												
Lawrenceburg 2												
Waterford 1												
New CT 1												
New CT 2												
New CT 3												
New CT 4												
Dresden												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-6 (page 3) (807 KAR 5:058 Sec.8.3.b.12.a.)
See Confidential Exhibit 4-6, AEP System-East Zone, Projected Operating Information (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Equivalent Availability Factors (%)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Amos 1												
Amos 2												
Amos 3												
W.C. Beckjord 6												
Big Sandy 1												
Big Sandy 2												
Cardinal 1												
Clinch River 1												
Clinch River 2												
Clinch River 3												
Conesville 3												
Conesville 4												
Conesville 5												
Conesville 6												
D. C. Cook 1												
D. C. Cook 2												
Gavin 1												
Gavin 2												
Glen Lyn 5												
Glen Lyn 6												
Kammer 1												
Kammer 2												
Kammer 3												
Kanawha River 1												
Kanawha River 2												
Mitchell 1												
Mitchell 2												
Mountaineer 1												
Muskingum River 1												
Muskingum River 2												
Muskingum River 3												
Muskingum River 4												
Muskingum River 5												
Picway 5												
Rockport 1												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-6 (page 4) (807 KAR 5:058 Sec.8.3.b.12.a.)
See Confidential Exhibit 4-6, AEP System-East Zone, Projected Operating Information (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Equivalent Availability Factors (%)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rockport 2												
Philip Sporn 1												
Philip Sporn 2												
Philip Sporn 3												
Philip Sporn 4												
Philip Sporn 5												
Stuart 1												
Stuart 2												
Stuart 3												
Stuart 4												
Tanners Creek 1												
Tanners Creek 2												
Tanners Creek 3												
Tanners Creek 4												
Zimmer 1												
Ceredo 1												
Ceredo 2												
Ceredo 3												
Ceredo 4												
Ceredo 5												
Ceredo 6												
Darby 1												
Darby 2												
Darby 3												
Darby 4												
Darby 5												
Darby 6												
Lawrenceburg 1												
Lawrenceburg 2												
Waterford 1												
New CT 1												
New CT 2												
New CT 3												
New CT 4												
Dresden												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-6 (page 5) (807 KAR 5:058 Sec.8.3.b.12.b.)
See Confidential Exhibit 4-6, AEP System-East Zone, Projected Operating Information (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Average Heat Rates (MMBtu/MWh)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Amos 1												
Amos 2												
Amos 3												
W.C. Beckjord 6												
Big Sandy 1												
Big Sandy 2												
Cardinal 1												
Clinch River 1												
Clinch River 2												
Clinch River 3												
Conesville 3												
Conesville 4												
Conesville 5												
Conesville 6												
D. C. Cook 1												
D. C. Cook 2												
Gavin 1												
Gavin 2												
Glen Lyn 5												
Glen Lyn 6												
Kammer 1												
Kammer 2												
Kammer 3												
Kanawha River 1												
Kanawha River 2												
Mitchell 1												
Mitchell 2												
Mountaineer 1												
Muskingum River 1												
Muskingum River 2												
Muskingum River 3												
Muskingum River 4												
Muskingum River 5												
Picway 5												
Rockport 1												

* The 2009 projection reflects data for June through December

Confidential Exhibit 4-6 (page 6) (807 KAR 5:058 Sec.8.3.b.12.b.)
See Confidential Exhibit 4-6, AEP System-East Zone, Projected Operating Information (6 pages) provided in the Confidential Supplement to this filing.

REDACTED

AEP SYSTEM - EAST ZONE
STEAM GENERATING CAPACITY
Projected Average Heat Rates (MMBtu/MWh)
(2009 - 2020)

Unit	2009*	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Rockport 2												
Philip Sporn 1												
Philip Sporn 2												
Philip Sporn 3												
Philip Sporn 4												
Philip Sporn 5												
Stuart 1												
Stuart 2												
Stuart 3												
Stuart 4												
Tanners Creek 1												
Tanners Creek 2												
Tanners Creek 3												
Tanners Creek 4												
Zimmer 1												
Ceredo 1												
Ceredo 2												
Ceredo 3												
Ceredo 4												
Ceredo 5												
Ceredo 6												
Darby 1												
Darby 2												
Darby 3												
Darby 4												
Darby 5												
Darby 6												
Lawrenceburg 1												
Lawrenceburg 2												
Waterford 1												
New CT 1												
New CT 2												
New CT 3												
New CT 4												
Dresden												

* The 2009 projection reflects data for June through December

AEP SYSTEM - EAST ZONE
Projected Summer Peak Demands, Generating Capabilities, and Margins
Based on (May 2009) Load Forecast
(2007 - 2023)
2009 KPCo IRP

Summer Season		Peak Demand - MW: Internal Demand (a)	Other Internal Demand	Interruptible Demand	DSM and Solar (b)	Net Internal Demand	Committed Net Sales (c)	Total Demand	Capacity - MW: Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Planned Capacity Additions: Units	Planned Capacity Additions: MW (f)	Annual Purchases	Total Capacity	Reserve Margin After Interruptible: w/o New Capacity	% of Demand	w/ New Capacity	% of Demand
		(1)	(2)	(3)	(4)	(5) =Sum(1-4)	(6)	(7) =(5)+(6)	(8)	(9)	(10)	(11)	(12)	(13) =((8)-(9)) +Sum(11)+(12)	(14) =(13)-Sum(11)-(7)	(15) =(14)/(7)*100	(16) =(13)-(7)	(17) =(16)/(7)*100
2007	Actual	22,411	0	0	0	22,411	1,658	24,069	28,127	1,700				26,427	2,358	9.80	2,358	9.80
2008	Actual	21,608	0	0	0	21,608	1,282	22,890	28,260	163				28,097	5,207	22.70	5,207	22.70
2009		21,136	0	(280)	(59)	20,797	1,273	22,070	28,129	1,124	200 MW Wind	26	0	27,031	4,935	22.40	4,961	22.50
2010		21,308	0	(615)	(150)	20,543	1,274	21,817	27,640	1,123	350 MW Wind	46	0	26,589	4,700	21.50	4,772	21.90
2011		22,640	0	(615)	(276)	21,749	1,052	22,801	27,648	1,052	600 MW Wind	78	0	26,746	3,795	16.60	3,945	17.30
2012		22,869	0	(615)	(284)	21,970	1,043	23,013	27,091	(33)	60 MW Bio Mass & 700 MW Wind	151	0	27,425	4,111	17.90	4,412	19.20
2013		23,149	0	(615)	(293)	22,241	1,043	23,284	27,081	(35)	540 MW D CC2 & 500 MW Wind	605	0	28,022	3,832	16.50	4,738	20.30
2014		23,354	0	(615)	(304)	22,435	1,043	23,478	26,701	(33)				27,640	3,256	13.90	4,162	17.70
2015		23,551	0	(615)	(314)	22,622	1,043	23,665	26,366	(64)				27,336	2,765	11.70	3,671	15.50
2016		23,698	0	(615)	(324)	22,759	1,043	23,802	26,416	(64)	100 MW Wind	13	0	27,399	2,678	11.30	3,597	15.10
2017		23,926	0	(615)	(333)	22,978	1,043	24,021	25,894	(64)				26,877	1,937	8.10	2,856	11.90
2018		24,103	0	(615)	(345)	23,143	1,043	24,186	25,382	(66)	127 MW Bio Mass	127	0	26,494	1,262	5.20	2,308	9.50
2019		24,274	0	(615)	(357)	23,302	1,043	24,345	24,856	(69)				25,971	580	2.40	1,626	6.70
2020		24,387	0	(615)	(368)	23,404	1,043	24,447	24,696	(69)	200 MW Wind	26	0	25,837	318	1.30	1,390	5.70
2021		24,633	0	(615)	(393)	23,625	1,043	24,668	24,006	(69)	127 MW Bio Mass & 150 MW Wind	147	0	25,293	(593)	(2.40)	625	2.50
2022		24,841	0	(615)	(429)	23,797	1,043	24,840	24,006	(69)	100 MW Wind	13	0	25,306	(765)	(3.10)	466	1.90
2023		25,043	0	(615)	(429)	23,999	1,043	25,042	23,305	(70)	100 MW Wind	13	0	24,619	(1,667)	(6.70)	(423)	(1.70)

Notes:

(a) Based on (May 2009) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved DSM plus projected solar resource impact.

(c) Includes:
East-West transfer in 2007 (250 MW)
Buckeye-Cardinal commitment
NCEMC sale, through 2010 (220 MW)

(d) Reflects the following summer capability assumptions:
AEP PPR share of OVEC capacity: 951 MW (Summer)
Hydro plants, including Summersville, are rated at average August output
WIND FARM (nameplate):
75 MW Total
EFFICIENCY IMPROVEMENTS:
2007: Mountaineer 1: 0 MW (turbine) (offset to FGD derate)
2008: Cardinal 2: 0 MW (turbine) (offset to FGD derate) ; Rockport 1: 20 MW (turbine)
2009: Amos 3: 35 MW (valve); Big Sandy 1: 0 MW (turbine); Gavin 1: 0 MW (turbine)
2011: Cook 2: 14 MW (Uprate); Gavin 2: 0 MW (turbine)
2012: Amos 2: 12 MW (turbine)
2013: Amos 1: 12 MW (turbine)
2014: Cook 2: 45 MW (Uprate)
2015: Cook 1: 100 MW (Uprate); Cook 2: 68 MW (Uprate)
2016: Cook 1: 68 MW (Uprate)
2017: Cook 2: 68 MW (Uprate); Rockport 1: 35 MW (valve) (offset to FGD derate)
2018: Cook 1: 68 MW (Uprate)
2019: Rockport 2: 35 MW (valve) (offset to FGD derate)

(d) continued
CCS DERATES:
2010: Mountaineer 1: 5 MW
2014: Mountaineer 1: 30 MW
2020: Mountaineer 1: 160 MW
SEPARATE INJECTION DERATES:
2015: Big Sandy 2: 25 MW; Muskingum R. 5: 18 MW
2019: Amos 3: 41 MW
2023: Rockport 1: 41 MW
FGD DERATES:
2007: Mitchell 1: 30 MW; Mitchell 2: 10 MW; Mountaineer 1: 20 MW
2008: Cardinal 1&2: 20 MW each; Stuart 1-4: 1 MW each
2009: Amos 3: 35 MW; Conesville 4: 2 MW
2010: Kyger Creek 3-5: 3 MW each
2011: Kyger Creek 1-2: 3 MW each
2012: Amos 2: 22 MW; Cardinal 3: 10 MW; Clifty Creek 1-6: 2 MW each;
2013: Amos 1: 22 MW
2015: Big Sandy 2: 40 MW
2016: Muskingum R. 5: 10 MW
2017: Rockport 1: 35 MW
2019: Rockport 2: 35 MW
SCR DERATES:
2009: Conesville 4: 0 MW
2016: Conesville 5-6: 4 MW each
2017: Rockport 1: 0 MW
2019: Rockport 2: 0 MW

(d) continued
RETIREMENTS:
2010: 440 MW
2012: 560 MW
2014: 395 MW
2015: 420 MW
2017: 600 MW
2018: 580 MW
2019: 485 MW
2021: 690 MW
2023: 660 MW

(e) Includes:
CPL unit power sale of 250 MW through 2009
Darby and Lawrenceburg are sold in the 2007/08 RPM auction
Sale of 50 MW to Wisconsin Public Service in 2007
Sale of 100 MW to Wolverine in 2007 - 2009, netted against a 100 MW purchase from Dynegy in 2008
Purchase to cover CSP's former Monongahela Power load in 2007 - 2009
Purchase from Constellation (315 MW), 2009 through 2011
Contractual share of remaining Mone capacity
MISO Sale of 348 MW in 2008 and 25 MW in 2009
Sale of 22 MW from Tanners Ck. 4 in 2010-2014
RPM Auction Sales 2007-2011 (775 MW, 1408 MW, 1379 MW , 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) New wind capacity value is assumed to be 13% of nameplate

KENTUCKY POWER COMPANY
Projected Winter Peak Demands, Generating Capabilities, and Margins
Based on (May 2009) Load Forecast
(2007/2008 - 2022/2023)
2009 KPCo IRP

		Peak Demand - MW							Capacity - MW						Reserve Margin - MW			
		(1)	(2)	(3)	(4)	(5) =Sum(1-4)	(6)	(7) =Sum(5-6)	(8)	(9)	(10)	(11)	(12)	(13) =((8)-(9)) +Sum(11)+(12)	(14) =(13)-(5)	(15) =(14)/(5)*100	(16) =(13)-(7)	(17) =(16)/(7)*100
Winter Season		Internal Demand (a)	Internal Wholesale Contracts	DSM and Solar (b)	Committed Sales (c)	Net Demand	Interruptible Demand	Total Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Planned Capacity Additions Units	Planned Capacity Additions MW (f)	Annual Purchases	Total Capacity	Reserve Margin Before Interruptible	% of Internal Demand	Reserve Margin After Interruptible	% of Internal Demand
2007/08	Actual	1,678	0	0	14	1,692	0	1,692	1,450	(7)				1,457	(235)	(13.90)	(235)	(13.90)
2008/09		1,615	0	(1)	15	1,629	0	1,629	1,453	117				1,336	(293)	(18.00)	(293)	(18.00)
2009/10		1,640	0	(1)	15	1,654	0	1,654	1,453	72				1,381	(273)	(16.50)	(273)	(16.50)
2010/11		1,670	0	(2)	0	1,668	0	1,668	1,453	72	50 MW Wind	6	0	1,387	(281)	(16.80)	(281)	(16.80)
2011/12		1,674	0	(2)	0	1,672	0	1,672	1,453	66	50 MW Wind	6	0	1,400	(272)	(16.30)	(272)	(16.30)
2012/13		1,691	0	(2)	0	1,689	0	1,689	1,453	(8)				1,474	(215)	(12.70)	(215)	(12.70)
2013/14		1,702	0	(2)	0	1,700	0	1,700	1,453	(9)				1,475	(225)	(13.20)	(225)	(13.20)
2014/15		1,713	0	(2)	0	1,711	0	1,711	1,428	(10)				1,451	(260)	(15.20)	(260)	(15.20)
2015/16		1,719	0	(2)	0	1,717	0	1,717	1,388	(11)				1,412	(305)	(17.80)	(305)	(17.80)
2016/17		1,730	0	(2)	0	1,728	0	1,728	1,388	(11)				1,412	(316)	(18.30)	(316)	(18.30)
2017/18		1,741	0	(2)	0	1,739	0	1,739	1,388	(11)				1,412	(327)	(18.80)	(327)	(18.80)
2018/19		1,752	0	(2)	0	1,750	0	1,750	1,388	(11)				1,412	(338)	(19.30)	(338)	(19.30)
2019/20		1,756	0	(2)	0	1,754	0	1,754	1,388	(11)				1,412	(342)	(19.50)	(342)	(19.50)
2020/21		1,773	0	(2)	0	1,771	0	1,771	1,388	(11)				1,412	(359)	(20.30)	(359)	(20.30)
2021/22		1,786	0	(2)	0	1,784	0	1,784	1,388	(11)				1,412	(372)	(20.90)	(372)	(20.90)
2022/23		1,793	0	(2)	0	1,791	0	1,791	1,382	(11)				1,406	(385)	(21.50)	(385)	(21.50)

Notes:

(a) Based on (May 2009) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved DSM plus projected solar resource impact.

(c) Includes companies MLR share of:
East-West transfer in 2007/08 (250 MW)
NCEMC sale, through 2009/10 (220 MW)

(d) Reflects the following Winter capability assumptions:
EFFICIENCY IMPROVEMENTS:
2007/08: Rockport 1: 20 MW (turbine)
2008/09: Big Sandy 1: 0 MW (turbine)
2017/18 Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve) (offset to FGD derate)

(d) continued
SEPARATE INJECTION DERATES:
2014/15: Big Sandy 2: 25 MW
2022/23: Rockport 1: 41 MW
FGD DERATES:
2015/16: Big Sandy 2: 40 MW
2017/18: Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
SCR DERATES:
2017/18: Rockport 1: 0 MW
2019/20: Rockport 2: 0 MW
RETIREMENTS:
2023/24: 260 MW

(e) Includes companies MLR share of:
Sale of 100 MW to Wolverine in 2007/08 - 2009/10, netted against a 100 MW purchase from Dynegy in 2007/08
Purchase from Constellation (315 MW), 2009/10 through 2011/12
Contractual share of remaining Mone capacity
MISO Sale of 348 MW in 2008/09 and 25 MW in 2009/10
Sale of 22 MW from Tanners Ck. 4 in 2010/11-2013/14
RPM Auction Sales 2007/08 - 2011/12 (775 MW, 1408 MW, 1379 MW, 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) New wind capacity value is assumed to be 13% of nameplate

Confidential Exhibit 4-9 (807 KAR 5:058 Sec.8.3.b.12.d.)

See Confidential Exhibit 4-9, the AEP System-East Zone, New Generation Technologies provided in the Confidential Supplement to this filing.

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AEP SYSTEM-EAST ZONE
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)
(Without Capital Deflator Adjustments)

Type	Capability (MW) Std. ISO	Capability (MW) Winter	Capability (MW) Summer	Installed Cost (d) ($/kW)	Trans. Cost (e) ($/kW)	Full Load Heat Rate (HHV,Btu/kWh)	Fuel Cost (f) ($/MMBtu)	Variable O&M ($/MWh)	Fixed O&M ($/kW-yr)	Emission Rates SO2 (g) (lb/MMBtu)	Emission Rates NOx (lb/MMBtu)	Emission Rates CO2 (lb/MMBtu)	Capacity Factor (%)	Overall Availability (%)
Base Load														
Pulv. Coal (Subcritical) (h)	618				24					0.06	0.070	205.3	85	90.7
Pulv. Coal (Subcritical) (h)	736				20					0.06	0.070	205.3	85	89.6
Pulv. Coal (Supercritical) (h)	618				24					0.06	0.070	205.3	85	90.7
Pulv. Coal (Supercritical) (h)	736				20					0.06	0.070	205.3	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	618				24					0.06	0.070	205.3	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	736				20					0.06	0.070	205.3	85	89.6
CFB (h)	585				26					0.06	0.070	210.3	80	90.7
IGCC (h)	630				24					0.06	0.057	205.3	85	87.5
Nuclear (MHI ABWR)	1.606				62					0.00	0.000	0.0	85	94.0
Base Load (50% CO2 Capture New Unit)														
Pulv. Coal (Subcritical) (h)	515				29					0.06	0.070	102.7	85	89.6
Pulv. Coal (Supercritical) (h)	515				29					0.06	0.070	102.7	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	515				29					0.06	0.070	102.7	85	89.6
IGCC (h)	578				26					0.06	0.057	102.7	85	87.5
Base Load (90% CO2 Capture New Unit)														
Pulv. Coal (Subcritical) (h)	433				35					0.0577	0.070	20.5	85	89.6
Pulv. Coal (Subcritical) (h)	515				29					0.0577	0.070	20.5	85	89.6
Pulv. Coal (Supercritical) (h)	433				35					0.0577	0.070	20.5	85	89.6
Pulv. Coal (Supercritical) (h)	515				29					0.0577	0.070	20.5	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	433				35					0.0577	0.070	20.5	85	89.6
Pulv. Coal (Ultra-Supercritical) (h)	515				29					0.0577	0.070	20.5	85	89.6
CFB (h)	410				37					0.0577	0.070	20.5	80	89.6
IGCC (h)	536				28					0.0585	0.057	20.5	85	87.5
IGCC (w/ CCS) (h)	536				28					0.0585	0.057	20.5	85	87.5
Intermediate														
Combined Cycle (2X1 GE7FA)	507				30					0.0007	0.008	116.0	85	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	619				24					0.0007	0.008	116.0	85	89.1
Combined Cycle (2X1 GE7FB)	538				28					0.0007	0.008	116.0	85	89.1
Combined Cycle (2X1 GE7FB. w/ Duct Firing)	650				23					0.0007	0.008	116.0	85	89.1
Intermediate (70% CO2 Capture New Unit)														
Combined Cycle (2X1 GE7FA)	447				34					0.0007	0.008	34.8	85	89.1
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	546				27					0.0007	0.008	34.8	85	89.1
Combined Cycle (2X1 GE7FB)	475				32					0.0007	0.008	34.8	85	89.1
Combined Cycle (2X1 GE7FB. w/ Duct Firing)	574				26					0.0007	0.008	34.8	85	89.1
Peaking														
Combustion Turbine (2X1GE7EA)	165				60					0.0007	0.033	116.0	5	90.1
Combustion Turbine (2X1GE7EA,w/ Inlet Chillers)	165				60					0.0007	0.009	116.0	5	90.1
Combustion Turbine (4X1GE7EA)	329				60					0.0007	0.033	116.0	5	90.1
Combustion Turbine (4X1GE7EA,w/ Inlet Chillers)	329				60					0.0007	0.009	116.0	5	90.1
Combustion Turbine (6X1GE7EA)	494				60					0.0007	0.033	116.0	5	90.1
Combustion Turbine (6X1GE7EA,w/ Inlet Chillers)	494				60					0.0007	0.009	116.0	5	90.1
Combustion Turbine (8X1GE7EA)	658				60					0.0007	0.033	116.0	5	90.1
Combustion Turbine (8X1GE7EA,w/ Inlet Chillers)	658				60					0.0007	0.009	116.0	5	90.1
Combustion Turbine (2X1GE7FA)	328				60					0.0007	0.033	116.0	5	90.1
Combustion Turbine (2X1GE7FA, w/ Inlet Chillers)	328				60					0.0007	0.009	116.0	5	90.1
Combustion Turbine (3X1GE7FA)	492				60					0.0007	0.033	116.0	5	90.1
Combustion Turbine (3X1GE7FA, w/ Inlet Chillers)	492				60					0.0007	0.009	116.0	5	90.1
Combustion Turbine (4X1GE7FA)	657				60					0.0007	0.033	116.0	5	90.1
Combustion Turbine (4X1GE7FA, w/ Inlet Chillers)	657				60					0.0007	0.009	116.0	5	90.1
Aero-Derivative (4X1GE LM6000PC)	181				60					0.0007	0.056	116.0	5	89.1
Aero-Derivative (1X GE LMS100)	96				60					0.0007	0.056	116.0	5	89.1
Aero-Derivative (1X GE LMS100, w/ Inlet Chillers)	96				60					0.0007	0.009	116.0	5	90.1
Aero-Derivative (2X1GE LMS100)	191				60					0.0007	0.056	116.0	5	89.1
Aero-Derivative (2X1GE LMS100. w/ Inlet Chillers)	191				60					0.0007	0.009	116.0	5	90.1

Notes: (a) Installed cost, capability and heat rate numbers have been rounded
(b) All costs in 2008 dollars. Assume 2.0% escalation rate for 2008 and beyond.
(c) $/kW costs are based on Standard ISO capability
(d) Total Plant & Interconnection Cost w/AFUDC (AEP-East rate of %,site rating $/kW)
(e) Transmission Cost ($/kW,w/AFUDC).
(f) Levelized Fuel Cost (40-Yr Period 2010-2049)
(g) Based on 4.5 lb Coal
(h) Pittsburgh #8 Coal.

AEP SYSTEM - EAST ZONE
Projected Summer Peak Demands, Generating Capabilities, and Margins
Based on (May 2009) Load Forecast
(2007 - 2023)
2009 KPCo IRP

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						=Sum(1-4)		=(5)+(6)						=((8)-(9))+Sum(11)+(12)	=(13)-Sum(11)-(7)	=(14)/(7)*100	=(13)-(7)	=(16)/(7)*100
		Peak Demand - MW							Capacity - MW						Reserve Margin After Interruptible			
Summer Season		Internal Demand (a)	Other Internal Demand	Interruptible Demand	DSM and Solar (b)	Net Internal Demand	Committed Net Sales (c)	Total Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Planned Capacity Additions Units	Planned Capacity Additions MW (f)	Annual Purchases	Total Capacity	w/o New Capacity	% of Demand	w/ New Capacity	% of Demand
2007	Actual	22,411	0	0	0	22,411	1,658	24,069	28,127	1,700				26,427	2,358	9.80	2,358	9.80
2008	Actual	21,608	0	0	0	21,608	1,282	22,890	28,260	163				28,097	5,207	22.70	5,207	22.70
2009		21,136	0	(280)	(59)	20,797	1,273	22,070	28,129	1,124	200 MW Wind	26	0	27,031	4,935	22.40	4,961	22.50
2010		21,308	0	(615)	(326)	20,367	1,274	21,641	27,640	1,123	350 MW Wind	46	0	26,589	4,876	22.50	4,948	22.90
2011		22,640	0	(615)	(629)	21,396	1,052	22,448	27,648	1,052	600 MW Wind	78	0	26,746	4,148	18.50	4,298	19.10
2012		22,869	0	(615)	(816)	21,438	1,043	22,481	27,091	(33)	60 MW Bio Mass & 700 MW Wind	151	0	27,425	4,643	20.70	4,944	22.00
2013		23,149	0	(615)	(1,007)	21,527	1,043	22,570	27,081	(35)	540 MW D CC2 & 500 MW Wind	605	0	28,022	4,546	20.10	5,452	24.20
2014		23,354	0	(615)	(1,196)	21,543	1,043	22,586	26,701	(33)				27,640	4,148	18.40	5,054	22.40
2015		23,551	0	(615)	(1,386)	21,550	1,043	22,593	26,366	(64)				27,336	3,837	17.00	4,743	21.00
2016		23,698	0	(615)	(1,396)	21,687	1,043	22,730	26,416	(64)	100 MW Wind	13	0	27,399	3,750	16.50	4,669	20.50
2017		23,926	0	(615)	(1,405)	21,906	1,043	22,949	25,894	(64)				26,877	3,009	13.10	3,928	17.10
2018		24,103	0	(615)	(1,417)	22,071	1,043	23,114	25,382	(66)	628 MW CT & 127 MW Bio Mass	755	0	27,122	2,334	10.10	4,008	17.30
2019		24,274	0	(615)	(1,429)	22,230	1,043	23,273	24,856	(69)				26,599	1,652	7.10	3,326	14.30
2020		24,387	0	(615)	(1,440)	22,332	1,043	23,375	24,696	(69)	200 MW Wind	26	0	26,465	1,390	5.90	3,090	13.20
2021		24,633	0	(615)	(1,464)	22,554	1,043	23,597	24,006	(69)	611 MW CC & 127 MW Bio Mass & 150 MW Wind	758	0	26,532	478	2.00	2,935	12.40
2022		24,841	0	(615)	(1,500)	22,726	1,043	23,769	24,006	(69)	628 MW CT & 100 MW Wind	641	0	27,173	306	1.30	3,404	14.30
2023		25,043	0	(615)	(1,500)	22,928	1,043	23,971	23,305	(69)	611 MW CC & 100 MW Wind	624	0	27,096	(597)	(2.50)	3,125	13.00

Notes:

(a) Based on (May 2009) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved DSM plus projected solar resource impact.

(c) Includes:
East-West transfer in 2007 (250 MW)
Buckeye-Cardinal commitment
NCEMC sale, through 2010 (220 MW)

(d) Reflects the following summer capability assumptions:
AEP PPR share of OVEC capacity: 951 MW (Summer)
Hydro plants, including Summersville, are rated at average August output
WIND FARM (nameplate):
75 MW Total
EFFICIENCY IMPROVEMENTS:
2007: Mountaineer 1: 0 MW (turbine) (offset to FGD derate)
2008: Cardinal 2: 0 MW (turbine) (offset to FGD derate) ; Rockport 1: 20 MW (turbine)
2009: Amos 3: 35 MW (valve); Big Sandy 1: 0 MW (turbine); Gavin 1: 0 MW (turbine)
2011: Cook 2: 14 MW (Uprate); Gavin 2: 0 MW (turbine)
2012: Amos 2: 12 MW (turbine)
2013: Amos 1: 12 MW (turbine)
2014: Cook 2: 45 MW (Uprate)
2015: Cook 1: 100 MW (Uprate); Cook 2: 68 MW (Uprate)
2016: Cook 1: 68 MW (Uprate)
2017: Cook 2: 68 MW (Uprate); Rockport 1: 35 MW (valve) (offset to FGD derate)
2018: Cook 1: 68 MW (Uprate)
2019: Rockport 2: 35 MW (valve) (offset to FGD derate)

(d) continued
CCS DERATES:
2010: Mountaineer 1: 5 MW
2014: Mountaineer 1: 30 MW
2020: Mountaineer 1: 160 MW
SEPARATE INJECTION DERATES:
2015: Big Sandy 2: 25 MW; Muskingum R. 5: 18 MW
2019: Amos 3: 41 MW
2023: Rockport 1: 41 MW
FGD DERATES:
2007: Mitchell 1: 30 MW; Mitchell 2: 10 MW; Mountaineer 1: 20 MW
2008: Cardinal 1&2: 20 MW each; Stuart 1-4: 1 MW each
2009: Amos 3: 35 MW; Con
2010: Kyger Creek 3-5: 3 MW each
2011: Kyger Creek 1-2: 3 MW each
2012: Amos 2: 22 MW; Cardinal 3: 10 MW; Clifty Creek 1-6: 2 MW each;
2013: Amos 1: 22 MW
2015: Big Sandy 2: 40 MW
2016: Muskingum R. 5: 10 MW
2017: Rockport 1: 35 MW
2019: Rockport 2: 35 MW
SCR DERATES:
2009: Conesville 4: 0 MW
2016: Conesville 5-6: 4 MW each
2017: Rockport 1: 0 MW
2019: Rockport 2: 0 MW

(d) continued
RETIREMENTS:
2010: 440 MW
2012: 560 MW
2014: 395 MW
2015: 420 MW
2017: 600 MW
2018: 580 MW
2019: 485 MW
2021: 690 MW
2023: 660 MW

(e) Includes:
CPL unit power sale of 250 MW through 2009
Darby and Lawrenceburg are sold in the 2007/08 RPM auction
Sale of 50 MW to Wisconsin Public Service in 2007
Sale of 100 MW to Wolverine in 2007 - 2009, netted against
a 100 MW purchase from Dynegy in 2008
Purchase to cover CSP's former Monongahela Power load in 2007 - 2009
Purchase from Constellation (315 MW), 2009 through 2011
Contractual share of remaining Mone capacity
MISO Sale of 348 MW in 2008 and 25 MW in 2009
Sale of 22 MW from Tanners Ck. 4 in 2010-2014
RPM Auction Sales 2007-2011 (775 MW, 1408 MW, 1379 MW , 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) New wind capacity value is assumed to be 13% of nameplate

AEP SYSTEM - EAST ZONE
Projected Winter Peak Demands, Generating Capabilities, and Margins
Based on (May 2009) Load Forecast
(2007/2008 - 2022/2023)
2009 KPCo IRP

Winter Season		(1)	(2)	(3)	(4)	(5) =Sum(1-4)	(6)	(7) =(5)+(6)	(8)	(9)	(10)	(11)	(12)	(13) =((8)-(9)) +Sum(11)+(12)	(14) =(13)-Sum(11)-(7)	(15) =(14)/(7)*100	(16) =(13)-(7)	(17) =(16)/(7)*100
		Peak Demand - MW							Capacity - MW						Reserve Margin After Interruptible			
		Internal Demand (a)	Other Internal Demand	Interruptible Demand	DSM and Solar (b)	Net Internal Demand	Committed Net Sales (c)	Total Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Planned Capacity Additions Units	Planned Capacity Additions MW (f)	Annual Purchases	Total Capacity	w/o New Capacity	% of Demand	w/ New Capacity	% of Demand
2007/08	Actual	21,977	0	0	0	21,977	1,275	23,252	28,790	1,798				26,992	3,740	16.10	3,740	16.10
2008/09		20,742	0	(591)	(37)	20,114	1,273	21,387	28,770	1,689	200 MW Wind	26	0	27,107	5,694	26.60	5,720	26.70
2009/10		20,433	0	(267)	(164)	20,002	1,273	21,275	28,773	784	250 MW Wind	33	0	28,048	6,715	31.60	6,773	31.80
2010/11		21,904	0	(591)	(312)	21,001	1,052	22,053	28,317	1,033	700 MW Wind	91	0	27,434	5,231	23.70	5,381	24.40
2011/12		22,045	0	(591)	(383)	21,071	1,043	22,114	28,391	962	700 MW Wind	91	0	27,670	5,315	24.00	5,556	25.10
2012/13		22,317	0	(591)	(456)	21,270	1,043	22,313	27,780	(123)	60 MW Bio Mass & 500 MW Wind	125	0	28,269	5,590	25.10	5,956	26.70
2013/14		22,485	0	(591)	(524)	21,370	1,043	22,413	27,825	(125)	625 MW D CC2	625	0	28,941	5,537	24.70	6,528	29.10
2014/15		22,640	0	(591)	(588)	21,461	1,043	22,504	27,432	(153)				28,576	5,081	22.60	6,072	27.00
2015/16		22,734	0	(591)	(588)	21,555	1,043	22,598	27,007	(154)	100 MW Wind	13	0	28,165	4,563	20.20	5,567	24.60
2016/17		22,886	0	(591)	(588)	21,707	1,043	22,750	27,143	(154)				28,301	4,547	20.00	5,551	24.40
2017/18		23,024	0	(591)	(588)	21,845	1,043	22,888	26,581	(154)				27,739	3,847	16.80	4,851	21.20
2018/19		23,160	0	(591)	(588)	21,981	1,043	23,024	25,940	(156)	683 MW CT & 127 MW Bio Mass	810	0	27,910	3,072	13.30	4,886	21.20
2019/20		23,222	0	(591)	(588)	22,043	1,043	23,086	25,445	(159)	200 MW Wind	26	0	27,444	2,518	10.90	4,358	18.90
2020/21		23,452	0	(591)	(588)	22,273	1,043	23,316	25,285	(159)	150 MW Wind	20	0	27,303	2,128	9.10	3,987	17.10
2021/22		23,625	0	(591)	(588)	22,446	1,043	23,489	24,580	(159)	669 MW CC & 127 MW Bio Mass & 100 MW Wind	809	0	27,407	1,250	5.30	3,918	16.70
2022/23		23,745	0	(591)	(596)	22,558	1,043	23,601	24,539	(159)	683 MW CT & 100 MW Wind	696	0	28,062	1,097	4.60	4,461	18.90

Notes:

(a) Based on (May 2009) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved DSM plus projected solar resource impact.

(c) Includes:
East-West transfer in 2007/08 (250 MW)
Buckeye-Cardinal commitment
NCEMC sale, through 2009/10 (220 MW)

(d) Reflects the following Winter capability assumptions:
AEP PPR share of OVEC capacity: 986 MW (Winter)
Hydro plants, including Summersville, are rated at average January output
WIND FARM (nameplate):
75 MW Total
EFFICIENCY IMPROVEMENTS:
2007/08: Cardinal 2: 0 MW (turbine) (offset to FGD derate) ; Rockport 1: 20 MW (turbine)
2008/09: Amos 3: 35 MW (valve); Big Sandy 1: 0 MW (turbine); Gavin 1: 0 MW (turbine)
2010/11: Cook 2: 14 MW (Uprate)
2011/12: Gavin 2: 0 MW (turbine)
2012/13: Amos 1: 12 MW (turbine); Amos 2: 12 MW (turbine)
2013/14: Cook 2: 45 MW (Uprate)
2014/15: Cook 1: 100 MW (Uprate)
2015/16: Cook 2: 68 MW (Uprate)
2016/17: Cook 1: 68 MW (Uprate); Cook 2: 68 MW (Uprate)
2017/18: Cook 1: 68 MW (Uprate); Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve) (offset to FGD derate)

(d) continued
CCS DERATES:
2010/11: Mountaineer 1: 5 MW
2014/15: Mountaineer 1: 30 MW
2020/21: Mountaineer 1: 160 MW
SEPARATE INJECTION DERATES:
2014/15: Big Sandy 2: 25 MW; Muskingum R. 5: 18 MW
2018/19: Amos 3: 41 MW
2022/23: Rockport 1: 41 MW
FGD DERATES:
2007/08: Cardinal 2: 20 MW; Mitchell 1: 30 MW; Stuart 3-4: 1 MW e
2008/09: Amos 3: 35 MW; Cardinal 1: 20 MW; Stuart 1-2: 1 MW each
2009/10: Conesville 4: 2 MW
2010/11: Kyger Creek 1-5: 3 MW each
2011/12: Cardinal 3: 10 MW; Clifty Ck 1-3, 2 MW each
2012/13: Amos 1: 22 MW; Amos 2: 22 MW; Clifty Ck 4-6, 2 MW each
2015/16: Big Sandy 2: 40 MW; Muskingum R. 5: 10 MW
2017/18: Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
SCR DERATES:
2009/10: Conesville 4: 0 MW
2015/16: Conesville 5-6: 4 MW each
2017/18: Rockport 1: 0 MW
2019/20: Rockport 2: 0 MW

(d) continued
RETIREMENTS:
2010/11: 450 MW
2012/13: 585 MW
2014/15: 420 MW
2015/16: 435 MW
2017/18: 630 MW
2018/19: 600 MW
2019/20: 495 MW
2021/22: 705 MW

(e) Includes:
CPL unit power sale of 250 MW through 2008/09
Darby and Lawrenceburg are sold in the 2007/08 RPM auction
Sale of 100 MW to Wolverine in 2007/08 - 2009/10, netted
against a 100 MW purchase from Dynegy in 2007/08
Purchase to cover CSP's former Monongahela Power load in 2007/08 - 2009/10
Purchase from Constellation (315 MW), 2009/10 through 2011/12
Contractual share of remaining Mone capacity
MISO Sale of 348 MW in 2008/09 and 25 MW in 2009/10
Sale of 22 MW from Tanners Ck. 4 in 2010/11-2013/14
RPM Auction Sales 2007/08 - 2011/12 (775 MW, 1408 MW, 1379 MW ,
1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) New wind capacity value is assumed to be 13% of nameplate

KENTUCKY POWER COMPANY
Projected Summer Peak Demands, Generating Capabilities, and Margins
Based on (May 2009) Load Forecast
(2007 - 2023)
2009 IRP

		(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)	(16)	(17)
						=Sum(1-4)		=Sum(5-6)						=((8)-(9)) +Sum(11)+(12)	=(13)-(5)	=(14)/(5)*100	=(13)-(7)	=(16)/(7)*100
		Peak Demand - MW							Capacity - MW						Reserve Margin - MW			
											Planned Capacity Additions							
Summer Season		Internal Demand (a)	Internal Wholesale Contracts	DSM and Solar (b)	Committed Sales (c)	Net Demand	Interruptible Demand	Total Demand	Existing Capacity & Planned Changes (d)	Committed Net Sales (e)	Units	MW (f)	Annual Purchases	Total Capacity	Reserve Margin Before Interruptible	% of Internal Demand	Reserve Margin After Interruptible	% of Internal Demand
2007	Actual	1,348	0	0	42	1,390	0	1,390	1,450	(5)				1,455	65	4.70	65	4.70
2008	Actual	1,249	0	0	16	1,265	0	1,265	1,452	(4)				1,456	191	15.10	191	15.10
2009		1,308	0	0	15	1,323	0	1,323	1,452	80				1,372	49	3.70	49	3.70
2010		1,338	0	(18)	16	1,336	0	1,336	1,452	80				1,372	36	2.70	36	2.70
2011		1,357	0	(37)	0	1,320	0	1,320	1,452	73	50 MW Wind	6	0	1,385	65	4.90	65	4.90
2012		1,364	0	(49)	0	1,315	0	1,315	1,452	(2)	50 MW Wind	6	0	1,467	152	11.60	152	11.60
2013		1,379	0	(61)	0	1,318	0	1,318	1,452	(2)				1,467	149	11.30	149	11.30
2014		1,389	0	(74)	0	1,315	0	1,315	1,452	(2)				1,467	152	11.60	152	11.60
2015		1,400	0	(86)	0	1,314	0	1,314	1,387	(5)				1,405	91	6.90	91	6.90
2016		1,408	0	(86)	0	1,322	0	1,322	1,387	(5)				1,405	83	6.30	83	6.30
2017		1,420	0	(86)	0	1,334	0	1,334	1,388	(5)				1,406	72	5.40	72	5.40
2018		1,431	0	(86)	0	1,345	0	1,345	1,388	(5)	314 MW CT	314	0	1,720	375	27.90	375	27.90
2019		1,441	0	(86)	0	1,355	0	1,355	1,388	(5)				1,720	365	26.90	365	26.90
2020		1,448	0	(86)	0	1,362	0	1,362	1,388	(5)				1,720	358	26.30	358	26.30
2021		1,462	0	(86)	0	1,376	0	1,376	1,388	(5)				1,720	344	25.00	344	25.00
2022		1,474	0	(86)	0	1,388	0	1,388	1,388	(5)				1,720	332	23.90	332	23.90
2023		1,483	0	(86)	0	1,397	0	1,397	1,122	(5)	306 MW CC	306	0	1,759	362	25.90	362	25.90

Notes:

(a) Based on (May 2009) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved DSM plus projected solar resource impact.

(c) Includes companies MLR share of:
East-West transfer in 2007 (250 MW)
NCEMC sale, through 2010 (220 MW)

(d) Reflects the members ownership ratio of following summer capability assumptions:
EFFICIENCY IMPROVEMENTS:
2008: Rockport 1: 20 MW (turbine)
2009: Big Sandy 1: 0 MW (turbine)
2017: Rockport 1: 35 MW (valve) (offset to FGD derate)
2019: Rockport 2: 35 MW (valve) (offset to FGD derate)

(d) continued
SEPARATE INJECTION DERATES:
2015: Big Sandy 2: 25 MW
2023: Rockport 1: 41 MW
FGD DERATES:
2015: Big Sandy 2: 40 MW
2017: Rockport 1: 35 MW
2019: Rockport 2: 35 MW
SCR DERATES:
2017: Rockport 1: 0 MW
2019: Rockport 2: 0 MW
RETIREMENTS:
2023: 260 MW

(e) Includes companies MLR share of:
Sale of 50 MW to Wisconsin Public Service in 2007
Sale of 100 MW to Wolverine in 2007 - 2009, netted
against a 100 MW purchase from Dynegy in 2007
Purchase from Constellation (315 MW), 2009 through 2011
Contractual share of remaining Mone capacity
MISO Sale of 348 MW in 2008 and 25 MW in 2009
Sale of 22 MW from Tanners Ck. 4 in 2010-2014
RPM Auction Sales 2007-2011 (775 MW, 1408 MW, 1379 MW
, 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) New wind capacity value is assumed to be 13% of nameplate

Exhibit 4-12 (807 KAR 5:058 Sec.8.3.b.1-11. and Sec. 8.3.c. and Sec. 8.4.a.)

KENTUCKY POWER COMPANY
Projected Winter Peak Demands, Generating Capabilities, and Margins
Based on (May 2009) Load Forecast
(2007/2008 - 2022/2023)
2009 IRP

Winter Season		(1) Internal Demand (a)	(2) Internal Wholesale Contracts	(3) DSM and Solar (b)	(4) Committed Sales (c)	(5) Net Demand =Sum(1-4)	(6) Interruptible Demand	(7) Total Demand =Sum(5-6)
		Peak Demand - MW						
2007/08	Actual	1,678	0	0	14	1,692	0	1,692
2008/09		1,615	0	(1)	15	1,629	0	1,629
2009/10		1,640	0	(8)	15	1,647	0	1,647
2010/11		1,670	0	(16)	0	1,654	0	1,654
2011/12		1,674	0	(18)	0	1,656	0	1,656
2012/13		1,691	0	(20)	0	1,671	0	1,671
2013/14		1,702	0	(22)	0	1,680	0	1,680
2014/15		1,713	0	(24)	0	1,689	0	1,689
2015/16		1,719	0	(24)	0	1,695	0	1,695
2016/17		1,730	0	(24)	0	1,706	0	1,706
2017/18		1,741	0	(24)	0	1,717	0	1,717
2018/19		1,752	0	(24)	0	1,728	0	1,728
2019/20		1,756	0	(24)	0	1,732	0	1,732
2020/21		1,773	0	(24)	0	1,749	0	1,749
2021/22		1,786	0	(24)	0	1,762	0	1,762
2022/23		1,793	0	(24)	0	1,769	0	1,769

Winter Season	(8) Existing Capacity & Planned Changes (d)	(9) Committed Net Sales (e)	(10) Planned Capacity Additions: Units	(11) Planned Capacity Additions: MW (f)	(12) Annual Purchases	(13) Total Capacity =((8)-(9)) +Sum(11)+(12)
	Capacity - MW					
2007/08	1,450	(7)				1,457
2008/09	1,453	117				1,336
2009/10	1,453	72				1,381
2010/11	1,453	72	50 MW Wind	6	0	1,387
2011/12	1,453	66	50 MW Wind	6	0	1,400
2012/13	1,453	(8)				1,474
2013/14	1,453	(9)				1,475
2014/15	1,428	(10)				1,451
2015/16	1,388	(11)				1,412
2016/17	1,388	(11)				1,412
2017/18	1,388	(11)	342 MW CT	342	0	1,412
2018/19	1,388	(11)				1,753
2019/20	1,388	(11)				1,753
2020/21	1,388	(11)				1,753
2021/22	1,388	(11)				1,753
2022/23	1,382	(11)				1,747

Winter Season	(14) Reserve Margin Before Interruptible =(13)-(5)	(15) % of Internal Demand =(14)/(5)*100	(16) Reserve Margin After Interruptible =(13)-(7)	(17) % of Internal Demand =(16)/(7)*100
	Reserve Margin - MW			
2007/08	(235)	(13.90)	(235)	(13.90)
2008/09	(293)	(18.00)	(293)	(18.00)
2009/10	(266)	(16.20)	(266)	(16.20)
2010/11	(267)	(16.10)	(267)	(16.10)
2011/12	(256)	(15.50)	(256)	(15.50)
2012/13	(197)	(11.80)	(197)	(11.80)
2013/14	(205)	(12.20)	(205)	(12.20)
2014/15	(238)	(14.10)	(238)	(14.10)
2015/16	(283)	(16.70)	(283)	(16.70)
2016/17	(294)	(17.20)	(294)	(17.20)
2017/18	(305)	(17.80)	(305)	(17.80)
2018/19	25	1.40	25	1.40
2019/20	21	1.20	21	1.20
2020/21	4	0.20	4	0.20
2021/22	(9)	(0.50)	(9)	(0.50)
2022/23	(22)	(1.20)	(22)	(1.20)

Notes:

(a) Based on (May 2009) Load Forecast (not coincident with PJM's peak)

(b) Existing plus approved DSM plus projected solar resource impact.

(c) Includes companies MLR share of:
East-West transfer in 2007/08 (250 MW)
NCEMC sale, through 2009/10 (220 MW)

(d) Reflects the following Winter capability assumptions:
EFFICIENCY IMPROVEMENTS:
2007/08: Rockport 1: 20 MW (turbine)
2008/09: Big Sandy 1: 0 MW (turbine)
2017/18 Rockport 1: 35 MW (valve) (offset to FGD derate)
2019/20: Rockport 2: 35 MW (valve) (offset to FGD derate)

(d) continued
SEPARATE INJECTION DERATES:
2014/15: Big Sandy 2: 25 MW
2022/23: Rockport 1: 41 MW
FGD DERATES:
2015/16: Big Sandy 2: 40 MW
2017/18: Rockport 1: 35 MW
2019/20: Rockport 2: 35 MW
SCR DERATES:
2017/18: Rockport 1: 0 MW
2019/20: Rockport 2: 0 MW

(e) Includes companies MLR share of:
Sale of 100 MW to Wolverine in 2007/08 - 2009/10, netted against a 100 MW purchase from Dynegy in 2007/08
Purchase from Constellation (315 MW), 2009/10 through 2011/12
Contractual share of remaining Mone capacity
MISO Sale of 348 MW in 2008/09 and 25 MW in 2009/10
Sale of 22 MW from Tanners Ck. 4 in 2010/11-2013/14
RPM Auction Sales 2007/08 - 2011/12 (775 MW, 1408 MW, 1379 MW, 1404 MW, 1391 MW ICAP)
3.6 MW capacity credit from SEPA's Philpot Dam via Blue Ridge contract

(f) New wind capacity value is assumed to be 13% of nameplate

KENTUCKY POWER COMPANY

Annual Internal Energy Requirements, Energy Resources and Energy Inputs

2009 - 2020

	Energy Requirements (GWh)			Energy Resources (GWh)								Energy Inputs (By Primary Fuel Type)					
				Generation (By Primary Fuel Type)					Firm Purchases			Coal-fired Generation		Gas-fired Generation		Bio-fired Generation	
Year	Base Forecast Internal Energy Requirements	Energy Efficiency(A)	Adjusted Energy	Coal	Gas	Bio	Hydro	Total	Other Utilities(B)	Wind	Total(C)	Tons (000)	MMBtu (000)	MCF (000)	MMBtu (000)	Tons (000)	MMBtu (000)
2009(D)	4,427	0	4,427	3,710	0	0	–	3,710	1,511	0	5,221	1,489	36,316	0	0	0	0
2010	7,909	(35)	7,874	5,834	0	0	–	5,834	2,832	16	8,682	2,325	56,535	0	0	0	0
2011	8,047	(73)	7,973	5,393	0	0	–	5,393	2,597	159	8,150	2,185	53,006	0	0	0	0
2012	8,112	(84)	8,028	6,388	0	0	–	6,388	2,534	288	9,210	2,583	62,443	0	0	0	0
2013	8,174	(94)	8,079	4,987	0	0	–	4,987	2,602	279	7,868	2,045	49,119	0	0	0	0
2014	8,227	(105)	8,122	5,851	0	0	–	5,851	2,405	287	8,542	2,399	57,573	0	0	0	0
2015	8,283	(115)	8,167	4,660	0	447	–	5,107	2,232	287	7,625	2,033	48,783	0	0	273	4,649
2016	8,344	(115)	8,229	5,536	0	525	–	6,061	2,424	288	8,774	2,432	58,357	0	0	325	5,531
2017	8,400	(115)	8,285	5,525	0	526	–	6,051	2,273	287	8,612	2,427	58,239	0	0	326	5,538
2018	8,456	(115)	8,340	4,792	99	454	–	5,345	2,571	287	8,203	2,103	50,471	1,010	1,035	281	4,781
2019	8,509	(115)	8,393	5,570	118	525	–	6,214	2,592	287	9,093	2,446	58,695	1,214	1,244	325	5,527
2020	8,561	(115)	8,446	5,534	111	520	–	6,165	2,966	288	9,419	2,431	58,355	1,134	1,163	323	5,484

Notes: (A) Represents incremental Energy Efficiency.
(B) Contracted energy amounts (other than wind energy) purchased from other utilities
(C) Sum of KPCo generated energy, energy purchased from other utilities, and wind purchases
(D) Respresents only the second half of 2009.

Exhibit 4-15 (807 KAR 5:058 Sec.6)

AEP SYSTEM - EAST ZONE
Comparison of 1999 and 2009 Capacity Expansion Plans (a)

January of Year	1999 Plan for 5-Company System (2001-2019) Block Additions (Undesignated MW) 5-Company System	KPCo Allocation	2009 Plan for East Zone (2009-2019) AEP Planned Resource Additions - MW (b) Renewables Solar	Wind	Biomass	Net Fossil and Nuclear (c)	Total	KPCo Net Allocated MW
2001	-	-						
2002	-	-						
2003	-	-						
2004	-	-						
2005	500	300						
2006	400	100						
2007	400	100						
2008	-	-						
2009	1,800	200						
2010	100	-	3	450	-	(2)	448	-
2011	700	100	3	700	-	(6)	694	50
2012	400	-	9	700	60	(16)	744	50
2013	800	-	14	500	-	(26)	474	-
2014	700	100	14	-	-	670	670	-
2015	1,500	100	14	-	-	27	27	(25)
2016	400	-	14	100	-	10	110	(40)
2017	400	-	13	-	-	68	68	-
2018	600	100	17	-	127	68	195	-
2019	400	-	18	-	127	683	810	342
Nameplate	9,100	1,100	119	2,450	314	1,476	4,240	377
Effective			0	319	314	1,476	2,109	290

Notes: (a) Excludes DSM comparison.
(b) Winter capacity
(c) Includes new capacity; includes upratings from efficiency improvements; includes derating impacts of biomass and environmental retrofits; excludes impact of potential retirements

Confidential Exhibit 4-16(807 KAR 5:058 Sec.8.3.a.)
See Confidential Exhibit 4-16, the AEP System- East Zone, Transmission Facilities map provided in the Confidential Supplement to this filing.

Confidential Exhibit 4-16

AEP System-East Zone, Transmission Facilities Map

CONFIDENTIAL INFORMATION REDACTED

Confidential Exhibit 4-17(807 KAR 5:058 Sec.8.3.a.)
See Confidential Exhibit 4-17, the AEP Transmission Line Network – Kentucky map provided in the Confidential Supplement to this filing.

Confidential Exhibit 4-17

AEP Transmission Line Network – Kentucky Map

CONFIDENTIAL INFORMATION REDACTED

Exhibit 4-18(807 KAR 5:058 Sec.5.4.)

AEP External Ties located in Kentucky

From	To	Voltage (kV)	Interchange Rating (MVA) Normal/Emergency Summer	Interchange Rating (MVA) Normal/Emergency Winter
Duke Energy Midwest (DEM) (Formerly Cinergy, Formerly CG&E)				
Tanners Creek (AEP/I&M)	East Bend	345	1195/1315	1195/1315
East Kentucky Power Cooperative (EKPC)				
Millbrook Park (AEP/OPC)	Argentum	138	205/215	215/215
Falcon (AEP/KPC)	Falcon	69	35/35	35/35
Grays Branch (AEP/KPC)	Argentum	69	39/46	54/58
Grayson (AEP/KPC)	Grayson	69	20/20	20/20
Leon (AEP/KPC)	Leon	69	54/54	54/54
Pelfrey (AEP/KPC)	Pelfrey	69	19/19	49/49
Thelma (AEP/KPC)	Thelma	69	78/96	103/106
Salt Lick (AEP/KPC)	Salt Lick	46	38/46	52/58
		Total	**488/531**	**582/595**
E.ON US (LGEE) (Formerly LG&E, Formerly KU)				
Wooten (AEP/KPC)	Hyden	161	300/404	379/418
Hillsboro (AEP/OPC)	Kenton	138	159/191	191/191
Morehead (AEP/KPC)	Rodburn (Morehead)	69	69/72	72/72
		Total	**528/667**	**642/681**
Tennesee Valley Authority (TVA)				
Leslie (AEP/KPC)	Pineville	161	216/249	289/330

I. CHAPTER 4, TECHNICAL APPENDIX

1.0 Resource Portfolio Modeling

1.1 The *Strategist* Model

The *Strategist* optimization model served as the empirical calculation basis from which the AEP-East zonal capacity requirement evaluations were examined and recommendations were made. As will be identified, as part of this iterative process, *Strategist* offers unique portfolios of resource options that can be assessed not only from a discrete, revenue requirement basis, but also for purposes of performing additional risk analysis outside the tool.

As its objective function, *Strategist* determines the regulatory least-cost resource mix for the generation ("G") system being assessed.[1] The solution is bounded by user-defined set of resource technologies, commodity pricing, and prescribed sets of constraints.

As described in the IRP Technical Addendum, *Strategist* develops a discrete macro (zone-specific) least-cost resource mix for a system by incorporating a variety of expansion planning assumptions including:

- Resource alternative characteristics (e.g., capital cost, construction period, project life).
- Operating parameters (e.g. capacity ratings, heat rates, outage rates, emission effluent rates, unit minimum downturn levels, must-run status, etc.) of existing and new units.
- Unit dispositions (retirement/mothballing).
- Delivered fuel prices.
- Prices of external market energy and capacity as well as SO_2 NO_X and CO_2emission allowances.
- Reliability constraints (in this study, minimum reserve margin targets).
- Emission limits and environmental compliance options.

These assumptions, and others, are considered in the development of an integrated plan that best fits the utility system being analyzed. *Strategist* does not develop a full regulatory cost-of-service (COS) profile. Rather, it typically considers only Generation (G)-COS that changes from plan-to-plan, not fixed embedded costs associated with existing generating capacity that would remain constant under any scenario. Likewise, transmission costs are included only to the extent that they are associated with new generating capacity, or are linked to specific supply alternatives. In other words, generic (nondescript or non site-specific) capacity resource modeling would typically not incorporate significant capital spends for transmission interconnection costs.

Specifically, *Strategist* includes and recognizes in its "incremental (again, largely 'G') revenue requirement" output profile:

- Fixed costs of capacity additions, i.e. carrying charges on capacity and associated transmission (based on a weighted average AEP System cost of capital), and fixed O&M;

[1] *Strategist* also offers the capability to address incremental transmission ("T") options that may be tied to evaluations of certain generating capacity resource alternatives.

- Fixed costs of any capacity purchases;
- Installation and administrative costs of DR/EE alternatives
- Variable costs associated with the entire fleet of new and existing generating units (developed using its probabilistic unit dispatch optimization engine). This includes fuel, purchased energy, market replacement cost of emission allowances, and variable O&M costs;
- Market revenues from external energy transactions (i.e. Off-System Sales) are netted against these costs under this ratemaking/revenue requirement format.

In the PROVIEW module of *Strategist*, the least-cost expansion plan is empirically formulated from potentially hundreds of thousands of possible resource alternative combinations created by the module's chronological dynamic programming algorithm. On an annual basis, each capacity resource alternative combination that satisfies various user-defined constraints (to be discussed below) is considered to be a "feasible state" and is saved by the program for consideration in following years. As the years progress, the previous years' feasible states are used as starting points for the addition of more resources that can be used to meet the current year's minimum reserve requirement. As the need for additional capacity on the system increases, the number of possible combinations and the number of feasible states increases exponentially with the number of resource alternatives being considered.

1.1.1 Modeling Constraints

The model's algorithm has the potential for creating such a vast number of alternative combinations and feasible states; it can become an extremely large computational and data storage problem, if not constrained in some manner. The *Strategist* model includes a number of input variables specifically designed to allow the user to further limit or constrain the size of the problem. There were numerous other known physical and economic issues that needed to be considered and, effectively, "constrained" during the modeling of the long-term capacity needs so as to reduce the problem size within the tool.

- Maintain an AEP-PJM installed capacity (ICAP) minimum reserve margin of roughly 15.5% per year as represented in the east region's "going-in" capacity position (which itself assumed a PJM Installed Reserve Margin [IRM] of 15.5% throughout the 2011/2012 planning year and 16.2% for remaining years of the planning period).
- All generation installation costs represent AEP-SEA view of capacity build prices that were predicated upon information from AEP Generation Technology Development.
- Under the terms of the New Source Review (NSR) Consent Decree, AEP agreed to annual SO_2 and NO_X emission limits for its fleet of 16 coal-fueled power plants in Indiana, Kentucky, Ohio, Virginia and West Virginia. These emission limits were met by adjusting the dispatch order of these units during *Strategist*'s economic dispatch modeling.

1.2 Resource Options/Characteristics and Screening

1.2.1 Supply-side Technology Screening

There are many variants of available supply and demand-side resource types. It is a practical limitation that not all known resource types are made available as modeling options. A screening of available supply-side technologies was performed with the optimum assets made subsequently available as options. Such screens for supply alternatives were performed for each of the major duty-cycle "families" (baseload, intermediate, and peaking).

The selected technology alternatives from this screening process do not necessarily represent the optimum technology choice for that duty cycle family. Rather, they reflect proxies for modeling purposes.

Other factors will be considered that will determine the ultimate technology type (e.g. choices for "peaking" technologies: GE frame machines "E" or "F", GE LMS100 aeroderivative machines, etc.).

Based on the established comparative economic screenings, the following specific supply alternatives were modeled in *Strategist* for each designated duty cycle:

- *Peaking capacity* was modeled as blocks of four, 165 MW GE-7FA Combustion Turbine units (summer rating of 157 MW x 4 = 628 MW), available beginning in 2017.
- *Intermediate capacity* was modeled as single natural gas Combined Cycle (2 x 1 GE-7FB with duct firing platform) units, each rated 650 MW (611 MW summer) available beginning in 2017.
- *Baseload capacity* burning eastern bituminous coals was modeled. The potential for future legislation limiting CO_2 emissions beginning in the 2020 timeframe was considered in selecting the solid fuel baseload capacity alternatives,. Two solid fuel alternatives were made available to the model:
  - ✓ 618 MW Ultra Supercritical PC unit (summer rating of 612 MW) where the unit is assumed to be retrofitted with a chilled ammonia carbon capture and sequestration (CCS) technology by 2020 that would capture 90% of the unit's CO_2 emissions. The addition of the CCS retrofit would reduce the unit's capacity to 525 MW (520 MW summer). This alternative could be added by *Strategist* from 2017 through 2019. Under the scenario where CO_2 prices did not exist, this unit without the CCS retrofit was available for selection beginning in 2017;
  - ✓ 735 MW Ultra Supercritical PC unit/625 MW net of CCS (summer rating of 619 MW). CCS equipment would reduce 90% of the unit's carbon emissions installed during the unit's construction. This alternative could be added by *Strategist* beginning in 2020.and;

In addition, beginning in the year 2020:

- ✓ *Strategist* could select an 800 MW share of a 1,600 MW nuclear, Mitsubishi Heavy Industries (MHI) Advanced Pressurized Water Reactor (760 MW summer)

In order to maintain a balance between peaking, intermediate and baseload capacity resources, only four Combustion Turbine (CT) units could be added in any year. If the addition of four CTs was not sufficient to meet reliability requirements in a particular year, the model was required to add either intermediate and/or baseload capacity to meet the reliability targets.

1.2.2 Demand-side Alternative Screening

As described in Section 3 of this report, eighteen "blocks" of DR/EE programs were developed and evaluated in *Strategist*. The economics of the DR/EE blocks were screened in order to minimize the problem size of the full *Strategist* optimization. The DR/EE blocks were evaluated under all of the economic scenarios. The results of this screening analysis showed that about 375 MW were selected under all of the economic scenarios. The total DR impact assumed in the full optimization analysis for AEP-East was 1,074 MW.

1.3 *Strategist* Optimization

1.3.1 Purpose

Strategist should be thought of as a tool used in the development of potentially economically viable resource portfolios. It doesn't produce "the answer;" rather, it produces or suggests many portfolios that have different cost profiles under different pricing scenarios and sensitivities. Portfolios that fare well under all scenarios and sensitivities are considered for further evaluation. The optimum, or least-cost, portfolio under one scenario may not be a low-cost, or even a viable portfolio in other scenarios. Portfolio selection may reflect strategic decisions embraced by AEP leadership, including a commitment to DR/EE, renewable resources and clean coal technology. *Strategist* results, both "optimum" and "suboptimum," serve as a starting point for constructing model portfolios.

For example, if a scenario dictates an unconstrained *Strategist* consistently picks a CT option to the point that such peaking capacity is being added in large quantities, a portfolio that substitutes a 650 MW combined cycle plant for four,165 MW CTs might be constructed and tested through *Strategist* to see if the resultant economic answer (i.e., CPW of revenue requirements) is significantly different. Intervening in the algorithm of *Strategist* to insert some additional practical constraints or conform to an AEP strategy yields a solution that is more realistic and not injuriously more expensive. The optimum or least expensive portfolio under a scenario may have practical limitations that *Strategist* does not take into full account.

1.3.2 Strategic Portfolios

Management commitments as outlined in the *AEP 2009 Corporate Sustainability Report* that were considered when constructing the underlying AEP-East resource portfolios include:

- **Renewable Resources:**
  - ✓ On an AEP system-wide basis, to achieve 7% of energy sales from renewable energy sources by 2013, 10% by 2020 and 15% by 2030.
  - ✓ Recognition of potential for a Federal RPS and mandatory state RPS in Ohio, Texas, Michigan, and West Virginia and voluntary RPS in Virginia.
- **Assumptions on "early mover" commitment to these GHG and renewable strategies**
  - ✓ Limit exposure to scarce resource pricing.
  - ✓ Take advantage of current tax credit for renewable generation.
  - ✓ Reduce exposure to potential GHG legislation, as initial mitigation requirements unfold.

- ✓ Plan to be in concert with other CO_2/GHG reduction options (offsets, allowances, etc.).

- **Energy efficiency:** Consideration of increased levels of cost-effective DR/EE over previous resource planning cycles reflect stakeholder desires for such measures, as well as regulator willingness in the form of revenue recovery certainty.

As will be described, additional sensitivities were then contemplated to determine the effects of the optimum portfolios, as well as to build additional portfolios. The build plans that were suggested by *Strategist* under the various scenarios and sensitivities are described in the following sections.

1.4 Optimum Build Portfolios for Four Economic Scenarios

1.4.1 Optimal Portfolio Results by Scenario

Given the four fundamental pricing scenarios developed by AEP-FA, as well as the modeling constraints and certain planning commitments, *Strategist* modeling was used to develop the incremental portfolios identified in **Exhibit T1-1**:

Exhibit T1-1: Model Optimized Portfolios Under Various Power Pricing Scenarios

	Business As Usual Case Optimization	Abundance Case Optimization	Reference Case Optimization	Constrained Case Optimization
2009				
2010				
2011				
2012				
2013				
2014				
2015				
2016				
2017				
2018	4 - 165 MW CTs, 1 - 625 MW PC w/o CCS	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC
2019				
2020				
2021	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs
2022				
2023	4 - 165 MW CTs, 1 - 625 MW PC w/o CCS	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	1 - 800 MW Nuke
2024				4 - 165 MW CTs
2025	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs
2026	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	
2027				4 - 165 MW CTs
2028	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	1 - 800 MW Nuke
2029				
2030	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	
<u>2009-2035 Total East System Cost</u>				
CPW ($M)	75,102	81,155	97,264	127,927
Levelized ($/MWh)	65.76	69.48	79.43	98.37
<u>Number of Units Added</u>				
CT	28	28	28	20
CC	0	2	2	1
PC	2	0	0	0
<u>Nuclear</u>	<u>0</u>	<u>0</u>	<u>0</u>	<u>2</u>
Total Capacity (MW)	5,856	5,920	5,920	5,550
Total Optimized DSM (MW Reduced)	1,074	984	1074	1,128

Notes:

1) *Because Renewable assets and a base level of incremental DR/EE are included in all portfolios, Strategist <u>did not</u> represent them as incremental resources within these comparative portfolio views.*
2) *The total capacity of the supply-side additions assumes that the 540 MW Dresden CC unit would become operational in <u>April 2013</u>.*
3) *The IRP planning horizon extends to 2019 as represented by the horizontal line. For modeling purposes Strategist constructs portfolios through 2030.*

1.4.2 Observations: Baseload Need Assessment

As shown in Exhibit T1-1, baseload capacity (Nuclear or Coal) was added in only the extreme pricing scenarios. In the Business As Usual (BAU) Case, no cost was assumed for CO_2 emissions and the coal alternative benefited from not incurring the increased cost of CCS equipment. Under the BAU Case conditions, coal additions were made to help replace the significant amount of existing capacity being retired in the 2015 to 2025 timeframe. Nuclear additions become an economic means of replacing the retired capacity under the Constrained Case where commodity prices are the highest of the four scenarios and costly CCS equipment is required on the PC additions. However, even with the additional cost of the CCS equipment a suboptimal plan that includes PC additions is only $70 million more expensive than the plan with nuclear additions.

Under the Reference Case, the 2018 and 2023 combined cycle additions operate over a broad range of capacity factors from 20% - 40% prior to all of the older coal unit retirements (2018-2025) and 40%-60% once all of the older coal units have been retired (post 2025). Under the Reference Case conditions, a plan that adds a PC with CCS equipment in 2023 is $65 million more expensive than the optimal plan with CC additions.

Under the Abundance Case, the commodity prices are low enough that the additional cost of a PC with CCS equipment is not justifiable. The cost of a PC with CCS under these conditions is $160 million more expensive than the optimal plan.

1.4.3 Additional Portfolio Evaluation

As an extension of the optimal portfolios created under the four pricing scenarios, nine additional portfolios were tested, or developed around defined objectives. These nine portfolios were created with the goal of examining the economics of portfolios created under factors and influences other than commodity prices. These nine portfolios can be defined as follows:

- "Best Contrary" Base/High Plan for Baseload Coal Solution
- "Best Contrary" Base/High Plan for Nuclear Solution
- Optimization without post 2020 CCS Requirement on New Coal
- Enhanced Renewables
- "Green Plan" – Best Enhanced Renewables Plan that includes Nuclear
- Demand Destruction
- Demand Destruction plus "Accelerated" Coal Unit Retirements
- High DR/EE Bandwidth
- CO_2 Limited

Exhibit T1-2 provides a summary of these portfolios under Reference Case conditions.

Exhibit T1-2: Portfolio Summary

	Contrary Coal	Contrary Nuclear	No CCS Requirement on Coal Additions	Enhanced Renewables	Green Plan	Demand Destruction	Demand Destruction with Accelerated Retirements	High DR/EE Bandwidth Under Constrained Case	CO_2 Limited
2009									
2010									
2011									
2012									
2013									
2014									
2015									
2016									
2017									
2018	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs, 1 - 650 MW CC		4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs,
2019									
2020							4 - 165 MW CTs		Mountaineer 90% CCS
2021	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs		4 - 165 MW CTs	4 - 165 MW CTs,
2022						4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs, 1 - 800 MW Nuke	4 - 165 MW CTs, 1 - 650 MW CC
2023	4 - 165 MW CTs, 1 - 625 MW PC w/ CCS	1 - 800 MW Nuke	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs	1 - 800 MW Nuke	4 - 165 MW CTs			
2024		4 - 165 MW CTs		4 - 165 MW CTs			4 - 165 MW CTs		
2025	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs, 1 - 650 MW CC	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs
2026	4 - 165 MW CTs		4 - 165 MW CTs		4 - 165 MW CTs			4 - 165 MW CTs	4 - 165 MW CTs
2027		4 - 165 MW CTs		4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs		4 - 165 MW CTs	4 - 165 MW CTs
2028	4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs				4 - 165 MW CTs		4 - 165 MW CTs
2029				4 - 165 MW CTs	4 - 165 MW CTs	4 - 165 MW CTs		4 - 165 MW CTs	4 - 165 MW CTs, Gavin 1&2 90% CCS Retrofit
2030	4 - 165 MW CTs	4 - 165 MW CTs	1 - 618 MW PC w/o CCS				4 - 165 MW CTs		
2009-2035 Total East System Cost									
CPW ($M)	97.329	97.627	97.319	97.843	98.423	85.188	84.214	127.288	97.905
Levelized ($/MWh)	79.47	79.65	79.46	79.79	80.14	81.34	80.66	98.28	80.06
Number of Units Added									
CT	28	28	24	28	24	24	28	28	32
CC	1	1	2	1	1	1	0	0	1
PC	1	0	1	0	0	0	0	0	0
Nuclear	0	1	0	0	1	0	0	1	0
Total Capacity (MW)	5,895	6,070	5,878	5,270	5,410	4,610	4,620	5,420	5,930
Total Optimized DSM (MW Reduced)	1,074	1,074	1,074	1,074	1,074	1,074	1,074	1,692	1,692

1.4.3.1 "Best Contrary" Base/High Plan for Baseload Coal Solution

The objective behind examining this portfolio was to determine the increased cost of a portfolio that contained solid fuel addition(s) under Reference Case conditions, as well as under the other three pricing scenarios. A selected portfolio (Contrary Coal) containing solid fuel addition(s) was chosen from the suboptimal portfolios created under the Reference and Constrained Cases. The Contrary Coal portfolio was then "forced" into the other pricing scenarios (with the focus on the Reference Case) and its costs were determined and compared to the optimal portfolio from that scenario. Under Reference Case conditions, the Contrary Coal portfolio shown in Exhibit T1-2 was only $65M more expensive than the Reference Case optimal portfolio.

1.4.3.2 "Best Contrary" Base/High Plan for Baseload Nuclear Solution

Similar to the Contrary Coal portfolio, the objective behind examining a Contrary Nuclear portfolio was to determine the increased cost of a nuclear addition under the various pricing scenarios, again with the focus on the Reference Case conditions. Under Reference Case conditions, the Contrary Nuclear portfolio was approximately $365 million more expensive than the optimal portfolio for that scenario.

1.4.3.3 Optimization without post 2020 CCS Requirement on New Coal

The objective of this optimization was to test the viability of solid fuel additions without the burden of increased cost due to CCS equipment. Under Reference Case conditions, the optimization produced an optimal portfolio that added a PC at the very end of the planning period (i.e., 2030). This result indicates that even without the increased cost of the CCS equipment, that the commodity prices under the Reference Case conditions are not sufficiently high enough to warrant the additional capital cost of a solid fuel addition early in the planning period. As seen in Exhibit T1-2, the cost of this portfolio is $55 million more than the optimal portfolio for the Reference Case.

1.4.3.4 Enhanced Renewables

The Enhanced Renewable portfolio was created based on meeting increased AEP system-wide renewable energy targets. The renewable energy targets set for this scenario require that 7% of system-wide energy sales be met with renewable energy resources by 2013, 15% (versus 10%) by 2020 and 20% (versus 15%) by 2030. As shown in Exhibit T1-2, the Enhanced Renewable portfolio adds one less CC than the Reference Case optimal portfolio. However, the cost of the Enhanced Renewable portfolio is approximately $580 million more expensive than the Reference Case optimal portfolio. These results indicate that increasing the amount of renewable energy is not cost effective, at least under Reference Case conditions. However, under the Constrained Case conditions, the Enhance Renewable portfolio does provide some savings over the Constrained Case optimal portfolio.

1.4.3.5 "Green Plan"

The Green Plan portfolio was created from the Enhanced Renewables optimization run under the Reference Case conditions. The Green Plan maintained the same renewable energy targets as the Enhanced Renewables run, but included a nuclear unit in the early 2020 timeframe, in this instance 2023. The purpose of creating the Green Plan was to test the economics of a portfolio with a very low emissions profiles. As shown in Exhibit T1-2, the Green Plan is approximately $1.2 billion more expensive than the Reference Case optimal portfolio. These results indicate that increasing the amount of renewable energy and the addition of a nuclear unit to offset emissions is not cost effective, at least under Reference Case conditions.

1.4.3.6 Demand Destruction

The Demand Destruction portfolio was created based on a load forecast that reflects a 2.8% reduction in 2008 peak and energy levels through 2010. Beginning in 2011, the peak and energy was assumed to have no growth through 2013. From 2014 through 2035, the peak and energy was assumed to grow at an annual rate of 1%. As shown in Exhibit T1-2, the impact of the load forecast reductions resulted in capacity additions from the Reference Case being delayed from 2018 to 2021 and one less CC being added.

1.4.3.7 Demand Destruction plus "Accelerated" Coal Unit Retirements

In this scenario, there was a three-year acceleration in the timing of the coal unit retirements identified during the 2009 Unit Disposition Study. The acceleration in retirements was made possible due to the reduction in peak loads and energy from the Demand Destruction forecast. The purpose of this scenario was to evaluate the economics of accelerating the coal unit retirements. As seen in Exhibit T1-2, accelerating the coal unit retirements provides almost $1 billion in savings over the Demand Destruction optimal portfolio. The majority of these savings are driven by the fact that this portfolio does not add the CC unit found in the Demand Destruction optimal portfolio.

1.4.3.8 High DR/EE Bandwidth

The High DR/EE Bandwidth scenario was developed by increasing the DR/EE impacts from the Reference Case optimal plan by 50%. The DR/EE impacts were increased to determine if adding additional DR/EE was cost beneficial under the high prices of the Constrained Case. The additional DR/EE saves approximately $640 million over the Constrained Case optimal portfolio. These savings are generated primarily by the additional DR/EE impacts avoiding a CC addition found in the Constrained Case optimal portfolio.

1.4.3.9 CO_2 Limited

In this scenario, CO_2 emission limits were assumed to be placed on the AEP's East and SPP systems based on the continued prospect for comprehensive Climate Change/CO2 legislation that would seek to reduce such emission levels. As a proxy for such reductions, H.R. 2454 (the Waxman-Markey Bill) that was introduced in draft form in April, 2009 (as was ultimately passed by the U.S. House in June) was used. In 2020, the CO_2 emission limit was based on a 15% reduction (W-M called for 17%) from 2005 actual CO_2 emissions, or a limit of approximately 110 million metric tons for the AEP-East system. In 2030, the CO_2 emissions limit was based on a 40% reduction (W-M called for 42%) in 2005 CO_2 emissions, or a limit of approximately 82 million metric tons for the AEP-East system. These emission limits were also developed under the assumption that the AEP System would receive a maximum of 20 million metric tons of carbon offsets. These offsets were assigned to the East and West systems based on their prorate share of 2005 CO_2 emissions, with the East being allocated approximately 15.5 million metric tons and the West receiving 4.5 million metric tons.

In recognition of a CO_2 constrained environment, the CO_2 Limited optimizations were made under the High DR/EE Bandwidth and Enhanced Renewables assumptions. The reason for making this assumption was that under a CO_2 limited environment, AEP would make additional investments in DR/EE and renewables to reduce their CO_2 footprint. In addition, Mountaineer was assumed to receive a 90% CO_2 CCS retrofit in 2020 in light of the fact that this unit will be a site of some preliminary testing of CO_2 reducing technologies over the next 5 years.

As a first step in the optimization process, an economic screening of 50%, 70% and 90% CCS retrofits was performed on all of the 800 MW and 1,300 MW units in the East system's generation fleet. The CCS retrofits were screened assuming a 2020 and a 2030 in-service date to coincide with the implementation of CO_2 emission limits in 2020 and the further reduction of those limits in 2030. In general, the screening indicated that the 50% CCS retrofits were the most economic. The next step was to perform a full optimization of screened CCS retrofit alternatives to determine how the CO_2 limits could be met in the most economic manner. Prior to the full optimization, it was determined that in order to meet the CO_2 limits it was necessary to optimize around only the 90% CCS retrofits at 1,300 MW units. *Strategist* results indicated that the 2020 CO_2 targets could be met with the just the 90% CCS retrofit at Mountaineer that was assumed to be present in the existing system. Therefore, an optimization of other CCS retrofits in 2020 was not necessary. In 2030, the model was given the choice of the 90% CCS retrofits at Gavin 1&2, Rockport 1&2 and Amos 3 to meet the 2030 CO_2 emission target. From that optimization, the 90% CCS retrofits at Gavin 1&2 were determined to be the most economic means of meeting the 2030 CO_2 emission target.

A summary of each plan's costs over the full (2009-2035) extended planning horizon, and under the various pricing scenarios is shown in **Exhibit T1-3**.

Exhibit T1-3 Optimized Plan Results (2009-2035) Under Various Pricing Scenarios

Plan Comparison

New Capacity (Summer Rating)	Units	Capacity		BAU (No CO_2)	Abundance (Low Power)	Reference (Base Power)	Constrained (High Power)
No CO2 Price Optimal Plan							
CT	28	4,620	Total NPV-$B	75.10	81.35	97.48	128.79
CC	0	0	*$/MWh*	*65.76*	*69.60*	*79.56*	*98.87*
PC w/CCS	2	1,250	Fuel NPV-$B	52.02	44.96	50.49	55.22
New Wind[a]		3,220	*$/MWh*	*32.08*	*27.72*	*31.14*	*34.06*
Solar[b]		496					
Total		6,636					
DR[c]		1,074					
Low Power Price Optimal Plan							
CT	28	4,620	Total NPV-$B	75.22	81.55	97.27	128.19
CC	2	1,340	*$/MWh*	*65.82*	*69.48*	*79.41*	*98.48*
PC w/CCS	0	0	Fuel NPV-$B	53.47	46.52	52.53	58.22
New Wind[a]		3,220	*$/MWh*	*32.97*	*28.68*	*32.39*	*35.90*
Solar[b]		496					
Total		6,726					
DR[c]		984					
Base Power Price Optimal Plan							
CT	28	4,620	Total NPV-$B	75.22	81.16	97.26	128.18
CC	2	1,340	*$/MWh*	*65.83*	*69.50*	*79.43*	*98.50*
PC w/CCS	0	0	Fuel NPV-$B	53.46	46.50	52.51	58.20
New Wind[a]		3,220	*$/MWh*	*32.97*	*28.68*	*32.39*	*35.89*
Solar[b]		496					
Total		6,726					
DR[c]		1,074					
High Power Price Optimal Plan							
CT	20	3,300	Total NPV-$B	76.43	81.99	97.81	127.93
CC	1	670	*$/MWh*	*66.60*	*70.03*	*79.79*	*98.37*
Nuclear	2	1,600	Fuel NPV-$B	51.69	44.80	50.24	55.07
New Wind[a]		3,220	*$/MWh*	*31.89*	*27.64*	*31.00*	*33.98*
Solar[b]		496					
Total		6,336					
DR[c]		1,128					
Best Contrary Coal Plan							
CT	24	3,960	Total NPV-$B	75.56	81.32	97.33	128.02
CC	1	670	*$/MWh*	*66.04*	*69.60*	*79.47*	*98.40*
PC w/CCS	2	1,250	Fuel NPV-$B	52.92	45.89	51.72	57.02
New Wind[a]		3,220	*$/MWh*	*32.64*	*28.30*	*31.90*	*35.17*
Solar[b]		496					
Total		6,646					
DR[c]		1,074					
Best Contrary Nuclear Plan							
CT	28	4,620	Total NPV-$B	76.00	81.71	97.63	128.06
CC	1	670	*$/MWh*	*66.32*	*69.84*	*79.65*	*98.42*
Nuclear	1	800	Fuel NPV-$B	52.35	45.45	51.09	56.15
New Wind[a]		3,220	*$/MWh*	*32.29*	*28.03*	*31.51*	*34.63*
Solar[b]		496					
Total		6,856					
DR[c]		1,074					

Notes: a) New wind not in service by year-end 2009. Allowed a summer rating of 13% of nameplate.
b) Solar is allowed a summer rating of 70% of nameplate.
c) Demand Reduction, cumulative DSM peak reduction through 2015.

Exhibit T1-3 (Cont'd) Optimized Plan Results (2009-2035) Under Various Pricing Scenarios

			PRICING SCENARIOS											
			BAU			*AbundanceCase*			Reference Case			Constrained Case		
	Capacity Categories	Cost Categories	Capacity No.	Capacity MW	Cost	Capacity No.	Capacity MW	Cost	Capacity No.	Capacity MW	Cost	Capacity No.	Capacity MW	Cost
Optimized *without* CCS (post '20) requirement on new coal	Nuclear	Total CPW-$B	0	0	$75.10	0	0	$81.21	0	0	$97.32			
	PC	*$/MWh*	2	1,250	$65.76	0	0	$69.51	1	625	$79.46			
	CC	CPW Fuel-$B	0	0	$52.02	2	1,340	$46.23	2	1,340	$52.15			
	CT	*$/MWh*	28	4,620	$32.08	28	4,620	$28.51	24	3,960	$32.16			
	New Wind[a]			3,220			3,220			3,220				
	Solar[b]			496			496			496				
	Total			6,636			6,726			6,691				
	DR[c]			1,074			984			1,074				
Enhanced Renewables	Nuclear	Total CPW-$B				0	0	$82.23	0	0	$97.84	1	800	$127.92
	PC	*$/MWh*				0	0	$70.14	0	0	$79.79	0	0	$98.37
	CC	CPW Fuel-$B				1	670	$47.63	1	670	$53.24	1	670	$57.29
	CT	*$/MWh*				28	4,620	$29.37	28	4,620	$32.84	24	3,960	$35.35
	New Wind[a]						3,695			3,695			3,695	
	Solar[b]						715			715			715	
	Total						6,271			6,271			6,411	
	DR[c]						984			1,074			1,128	
Green Plan: Best Enhanced Renewables including nuclear	Nuclear	Total CPW-$B							1	800	$98.42	1	800	$128.09
	PC	*$/MWh*							0	0	$80.14	0	0	$98.47
	CC	CPW Fuel-$B							1	670	$51.83	1	670	$56.38
	CT	*$/MWh*							24	3,960	$31.96	24	3,960	$34.78
	New Wind[a]									3,695			3,695	
	Solar[b]									715			715	
	Total									6,411			6,411	
	DR[c]									1,074			1,128	
Demand Destruction	Nuclear	Total CPW-$B							0	0	$85.19	2	1600	$111.52
	PC	*$/MWh*							0	0	$81.34	0	0	$99.72
	CC	CPW Fuel-$B							1	670	$42.58	0	0	$42.59
	CT	*$/MWh*							24	3,960	$29.67	20	3,300	$29.69
	New Wind[a]									3,220			3,220	
	Solar[b]									496			496	
	Total									5,396			5,666	
	DR[c]									1,074			1,128	
Demand Destruction with Accelerated Unit Retirements	Nuclear	Total CPW-$B				0	0	$70.93	0	0	$84.21			
	PC	*$/MWh*				0	0	$71.38	0	0	$80.66			
	CC	CPW Fuel-$B				0	0	$39.04	0	0	$42.80			
	CT	*$/MWh*				28	4,620	$27.20	28	4,620	$29.83			
	New Wind[a]						3,220			3,220				
	Solar[b]						496			496				
	Total						5,386			5,386				
	DR[c]						984			1,074				
High DR/EE Bandwidth	Nuclear	Total CPW-$B										1	800	$127.29
	PC	*$/MWh*										0	0	$98.28
	CC	CPW Fuel-$B										0	0	$55.65
	CT	*$/MWh*										28	4,620	$34.44
	New Wind[a]												3,220	
	Solar[b]												496	
	Total												6,186	
	DR[c]												1,692	
CO2 Limited, utilizing all available options including retrofiting CCS on existing units	Nuclear	Total CPW-$B							0	0	$97.90	2	1600	$125.37
	PC	*$/MWh*							0	0	$80.06	0	0	$97.09
	CC	CPW Fuel-$B							1	670	$53.92	0	0	$57.03
	CT	*$/MWh*							36	5,940	$33.35	32	5,280	$35.29
	New Wind[a]									3,220			3,220	
	Solar[b]									496			496	
	Total									7,376			7,646	
	DR[c]									1,611			1,692	

Notes: a) New wind not in service by year-end 2009 Allowed a summer rating of 13% of nameplate
b) Solar is allowed a summer rating of 70% of nameplate
c) *Demand* Reduction, cumulative DSM peak reduction through 2015.

1.4.4 Development of the Hybrid Plan

Using the intelligence gained from the *Strategist* runs for various pricing and sensitivity scenarios, a "Hybrid" plan was created that primarily focused on the following:

- While the IRP process was taking place, the Economic Forecasting group prepared a revised load forecast in April, 2009 that was formally issued in May, 2009. The revised forecast reflected a downturn in economic conditions over AEP's service area and in turn, a reduction in AEP's peak and energy requirements compared to the forecast used in the IRP process. The "April" forecast showed a reduction in energy requirements of 4% - 5% and a 2% reduction in peak demand over the planning period compared to the load forecast used in the IRP process. In recognition of the April forecast's lower peak loads, the Hybrid Plan deferred the amount of capacity that had been added in the various IRP optimization runs.
- During the course of the IRP analysis in the Spring of 2009, it became apparent that reducing the size of AEP's significant carbon footprint would be necessary over the long-term due to the emerging likelihood of some level of CO_2 emission limits in the future. Based on the analysis performed within the "CO_2 Limited" sensitivity view, CCS retrofits were introduced into the AEP-East plan so as to accelerate this further migration to a reduced CO_2 position.
- Further, the Renewable Energy Plan that was used in all of the resource optimization runs was revised to reflect an acceleration of wind resource additions. This acceleration was likewise envisioned due to the growing prospect of a Federal Renewable Portfolio Standard either within comprehensive Climate Change/CO_2 legislation or that would be stand-alone. This revised Renewable Energy Plan was used in the development of the Hybrid Plan.

Based on the array of discrete results from varying pricing scenarios and strategic portfolios, the Reference Case Optimal Portfolio was determined to be a reasonable basis for the development of the final AEP-East Hybrid Plan shown in **Exhibit T1-4**. This portfolio generally provided the lowest CPW across the various scenarios when compared to the alternative plans. Also, no portfolio called for baseload capacity prior to 2022, which is outside of the 10 year planning horizon. This provides a level of certainty that any short term decisions made based on the Optimal Portfolio would be equally valid under other portfolios as well.

As stated above, during the development of the Hybrid Plan the timing and number of units added in the Reference Case Optimal Plan was adjusted to reflect the reduction in peak loads found in the April 2009 revised load forecast. In addition, the CCS retrofits identified in the CO_2 Limited optimization runs were also added as part of the Hybrid Plan, as well as the revised Renewable Energy Plan. The reduction in peaking requirements with the April load forecast allowed the number of peaking resources beyond 2018 to be reduced from 24 in the Reference Case to 12 in the Hybrid Plan, however an intermediate resource was added in place of four of these CT's to diversify the energy mix.

The Hybrid Plan identifies thermal capacity additions by duty cycle. With the exception of committed capacity additions, such as Dresden, or enhancements to existing resources, such as the Cook uprate, *the thermal capacity identified is intended to represent "blocks" of capacity that fit that duty cycle and do not imply a specific solution or configuration.*

Exhibit T1-4: Hybrid Plan

2009 IRP (Hybrid Plan) *AEP-East*

MW	*Planned Resource Reductions* (A)		*Planned Resource Additions* (A)							
			DSM		RENEWABLE			THERMAL		
	Unit Retirements (summer-rating)	Environmental Retrofits(G)	*Embedded* Demand Reduction(B) *(Cumul. Contribution)*	*New* Demand Reduction(C) *(Cumul. Contribution)*	Solar (Nameplate)	Wind (Nameplate)	Biomass (Derate / New Facility(D))	Duty Cycle Type: BL=Baseload INT=Intermediate/Cyclic PKG=Peaking	*Ownership*	
2009			58	0	0	200				
2010	(440)	MT-Ph1CCS(4 MW) RK1&2 ACI	145	179	10	350				
2011			267	358	3	601				
2012	(560)	AM2 FGD(F) (10 MW)	269	537	2	700	0 / 60			
2013		AM1 FGD(F)/CV 5&6SCR(18MW)	271	716	14	500		(Dresden) 540-MW INT	*APCo*	
2014	(395)	MT-Ph2 (31 MW)	272	894	14		-43 / 0	(Cook 2)+45MW BL	*I&M*	
2015	(415)	MR5/BS2 FGD (50 MW)	273	1,073	14			(Cook 1&2)+168MW BL	*I&M*	
2016			273	1.073	14	100		(Cook 1)+68MW BL	*I&M*	10 Year IRP Period
2017	(600)	RK1 FGD	273	1,073	13			(Cook 2)+68MW BL	*I&M*	
2018	(580)		273	1,073	17		-41 / 127	(Cook 1)+ 68MW BL and 628-MW PKG	*PKG: APCo/KPCo 50/50. BL: I&M*	
2019	(480)	RK2 FGD	273	1,073	17					
2019 Cumul. Contribution/Nameplate	*(3,470)*	*(113)*	***273***	***1,073***	***118***	***2,451***	***103***	***1,585***		
(PJM) Capacity Value (Wind 13%; Solar 70%(est.))					*83*	*319*				
2020		MT-Ph3 (160)	273	1,073	16	200				
2021	(690)		273	1,073	35	150	0 / 127	611-MW INT	*APCo*	
2022			273	1,073	52	100	-41 / 0	628-MW PKG	*APCo*	
2023	(660)		273	1,073	0	100		611-MW INT	*APCo/KPCo 50/50*	
2024			273	1,073	52	200				
2025	(500)		273	1,073	0	100		628-MW PKG	*APCo/CSP 50/50*	Extended Planning Horizon
2026			273	1,073	35	100	-41 / 0			
2027			273	1,073	0	100		611-MW INT	*I&M*	
2028			273	1.073	35	200				
2029			273	1,073	0					
2030		GV1&2 (390)	273	1,073	43			628-MW PKG	*APCo*	
2030 Cumul. Contribution/Nameplate	*(5,320)*	*(663)*	***273***	***1,073***	***384***	***3,701***	***148***	***5,302***		
(PJM) Capacity Value (Wind 13%; Solar 70%(est.))					*269*	*481*				
Cumul. (Nameplate) Contribution thru '30			*3%*	*10%*	*4%*	*34%*	*1%*	*49%*		
Cumul. (Capacity) Contribution thru '30			*4%*	*14%*	*4%*	*6%*	*2%*	*70%*		

'NET' CAPACITY RESOURCE ADDITIONS:	
2009-2020	*(147)*
2009-2030	*1,563*

Peaking	2,512	*47%*
Intermediate (incl Dresden)	2,373	*45%*
Baseload (D.C. Cook Uprates)	417	*8%*
	5,302	

(A) Not shown are smaller unit derates and uprates embedded in the current plan which are largely offseting (e.g FGD retrofit auxliary load loss, offset by turbine/MSV uprates)
(B) "Embedded" DSM represents 'known & measurable', commission-approved program activity now projected by AEP-Economic Forecasting in the most recent load forecast
(C) "New" DSM represents incremental activity projected based on estimated contribution & program cost (vs. avoided cost) parameters, from recent Market Potential Studies, and were generally limited to an EPRI Jan. '09 study identifying a "Realistically Achievable Potential". Note: Such 'New' (increm) DSM-DR activity modeled thru 2015 only
(D) Derate represents a blended fuel biomass unit, New Facility reflects a single repowered, (100%) dedicated biomass (e.g. stoker) unit from MR 1-4 and a 60 MW PPA

(F) Represents current in-service date, however parties to the Consent Decree have been petitioned to seek an extension of the in-service date to 2015
(G) CCS retrofit technology assumed to be chilled ammonia with a 15% parasitic load

For comparison purposes, a Reference Case plan was created using the same Renewable Plan as the Hybrid Plan. The Hybrid Plan was shown to be approximately $425 million less expensive than this adjusted Reference Case plan. The Hybrid Plan savings are due to many factors including a shift in resource needs due to the updated load forecast as well as the reduction in CO_2 emission costs due to the introduction of CCS retrofits in the extended planning horizon.

1.4.5 Portfolio Views Selected for Additional Risk Analysis

The following summarizes the seven portfolio views as set forth by the discrete AEP East capacity resource modeling performed using *Strategist* that were analyzed further in the Utility Risk Simulation Analysis (URSA) model described in Technical Appendix 2.0.

- Reference Case Optimal Plan
- "Best Contrary" Base/High Plan for Baseload Coal Solution
- "Best Contrary" Base/High Plan for Nuclear Solution
- Enhanced Renewables
- "Green Plan" – Best Enhanced Renewables Plan that includes Nuclear
- CO_2 Limited
- Hybrid Plan

These resource portfolio options created in *Strategist* and their revenue requirements offer modeled economic results based on specific, discrete "point estimates" of the variables that could affect these economics. These portfolios were evaluated over a *distributed range* of certain key variables in URSA, which provided a probability-weighted solution that offers additional insight surrounding relative cost/price risk.

2.0 Risk Analysis

Once seven plans were selected using *Strategist*, they were subjected to rigorous "stress testing" to ensure that none of the portfolios have outcomes that would be deleterious under a probabilistic array of input variables.

2.1 The URSA Model

Developed internally by AEP Market Risk Oversight, the Utility Risk Simulation Analysis (URSA) model uses Montè Carlo simulation of the AEP East Zone with 1,399 possible futures for certain input variables. The results take the form of a distribution of possible revenue requirement outcomes for each plan. The input variables or risk factors considered by URSA within this IRP analysis were:

- Eastern and Western coal prices,
- natural gas prices,
- power prices,
- SO_2, CO_2, and NO_X emissions allowance prices,
- full requirements loads,
- forced outages of AEP's units.

These variables were correlated based on historical data.

For each plan, the difference between its mean and its 95th percentile was identified as Revenue Requirement at Risk (RRaR). This represents a level of required revenue sufficiently high that it will be exceeded, assuming that the given plan were adopted, with an estimated probability of 5.0 percent.

Exhibit T2-1 illustrates for one plan, the "Hybrid Plan," the average levels of some key risk factors, both overall and in the simulated outcomes whose Cumulative Present Value (CPV) revenue requirement is roughly equal to or exceeds the upper bound of Revenue Requirement at Risk. Note that these CPV's are consistent with the CPW values calculated using the *Strategist* tool. The table is specific to the Hybrid Plan, but the numbers would be very similar under the other plans. (The particular alternative futures producing the highest levels are not the necessarily the same between different plans.)

Exhibit T2-1: Key Risk Factors–Weighted Means for 2009-2035

	Simulated Outcomes - Hybrid Plan			
	All Outcomes	RRaR-Exceeding Outcomes		
Variable	Mean	Mean	Difference	% Diff
AEP Internal Onpeak Load	17,114	17,111	(2.66)	-0.02%
AEP Onpeak Power Spot	73.95	78.29	4.34	5.87%
NYM Coal Spot	65.63	70.96	5.33	8.12%
Henry Hub Gas Spot	8.37	9.09	0.72	8.60%
CO2 Allowance Spot	24.69	42.46	17.77	71.97%
NOx Allowance Spot	734	736	1.58	0.22%
SO2 Allowance Spot	1,591	2,202	610.60	38.38%
Megawatts Forced Out	2,261	2,258	(2.54)	-0.11%

The price of CO_2 and SO_2 allowances is greater among the RRaR-exceeding outcomes, suggesting that they are critical sources of risk to revenue requirements. The relative difference between that "tail" and mean outcomes are 71.97% and 38.38%, which is significantly greater than the relative difference of other risk factors. On the other extreme, the possible futures associated with the RRaR-exceeding outcomes are characterized by slightly lower levels of load and megawatts forced out.

It might be assumed that the very worst possible futures would be characterized by high fuel and allowance prices and low power prices. But according to the analysis of the historical values of risk factors that underlies this study, such futures have essentially no chance of occurring. Any possible future with high fuel prices would essentially always have high power prices. Likewise the risk factor analysis implies an inverse correlation between NO_x allowance prices and some of the other risk factors that determine the tail cases, so that in these tail cases, the average NO_x allowance price is actually less than the average across all possible futures.

T2.2 URSA Modeling Results

Exhibits T2-2 and **T2-3** illustrate the distribution of outcomes for the Hybrid Plan on both a cumulative distribution "S-curve" and probability distribution ("bell-curve") basis, respectively. The graphs for the other six plans examined would be quite similar. The costs included in this analysis are the same as were included in the *Strategist* analysis, as described in Technical

Appendix 1.1, namely fixed costs of capacity additions; fixed costs of any capacity purchases; installation and administrative costs of DR/EE alternatives; variable costs for the entire fleet; and market revenues netted against costs.

Exhibit T2-2: Cumulative Probability Distribution of AEP-East Revenue Requirement

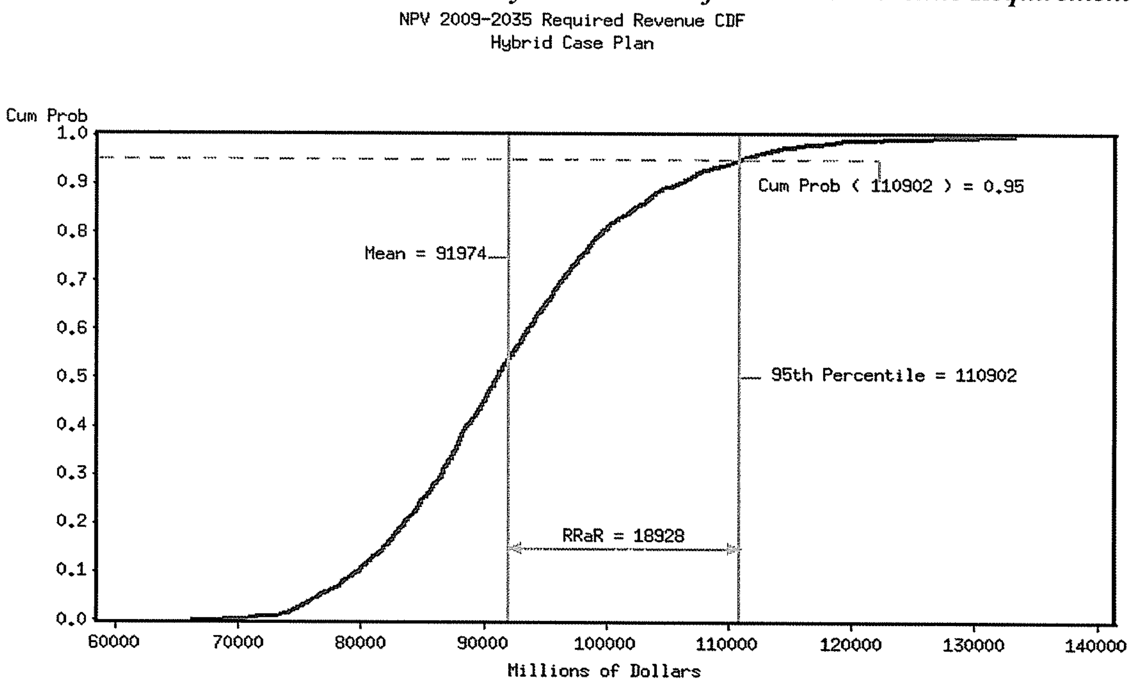
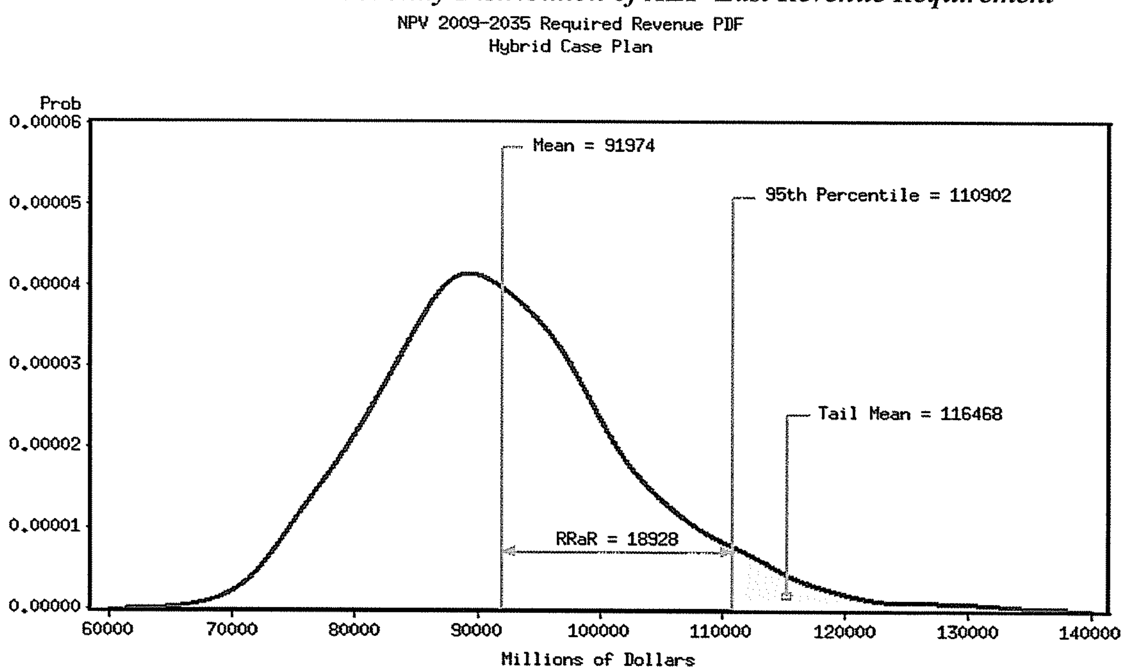


Exhibit T2-3: Probability Distribution of AEP-East Revenue Requirement



2.3 Installed Capital Cost Risk Assessment

In order to further scrutinize the seven plans under the 1399 possible futures, the impacts of Installed Capital Cost Risk on the URSA results were examined. A six-point capital cost distribution for each of the seven plans was created. (See **Exhibit T2-4** for its basis.) In creating the distribution for each plan, the installed capital costs of all types of generating capacity were assumed to be perfectly correlated with each other. The fixed representation of installed capital costs in URSA was removed from each URSA output distribution and the resulting distributions were convolved with the installed capital cost distributions.

Exhibit T2-4: Basis of Installed Capital Cost Distributions

Probability of occurrence, **Percent Capital Cost Variance**:	5%	19%	33%	23.67%	14.33%	5%
Solid-fuel Units	-15%	-7%	Base	+10%	+20%	+30%
Gas-fuel Units	-10%	-5%	Base	+6.67%	+13.33%	+20%
Nuclear Units	-15%	-7%	Base	+10%	+20%	+30%

2.4 Results Including Installed Capital Cost Risk

Exhibit T2-5 summarizes the Installed Capital Cost Risk-adjusted results for all seven AEP-East plans.

Exhibit T2-5: Risk -Adjusted CPW 2009-2035 Revenue Requirement ($ Millions)

PLAN	50th Percentile	95th Percentile	Revenue Requirement at Risk
BASE	91,854	114,210	22,356
CONTRARY NUKE	92,016	114,426	22,410
CONTRARY COAL	92,070	114,455	22,385
ENHANCED RENEWABLES	92,934	115,074	22,140
GREEN	92,988	115,128	22,140
CO_2 LIMITED	92,736	112,608	19,872
HYBRID	91,924	111,867	19,943

Exhibit T2-5 shows reasonably consistent results across all plans modeled. These comparative results also suggest that, given the fuel/generation diversity of the capacity resource options introduced into the analysis, the relative economic exposure would appear to be small irrespective of the plan selected.

The three lowest-cost plans at the 50th percentile are the Base, Hybrid, and Contrary Nuke plans. However, the lowest Revenue Requirement at Risk plan is the CO_2 limited plan, followed by the Hybrid plan, while the lowest cost plan at the 95th percentile is the Hybrid plan.

RRaR measures the risk relative to the 50th percentile, or expected, result of a plan. The plan with the least RRaR is not necessarily preferred for risk avoidance. Instead, low values of required revenue at extreme percentiles, such as the 95th, are preferred.

The estimated distributions of revenue required under the seven plans are rather similar. **Exhibits T2-6** and **T2-7** show the superimposed graphs of all seven distribution functions. **Exhibit T2-6** shows entire distributions; **Exhibit T2-7** shows only the region at or above the 95th percentile.

Exhibit T2-6: Distribution Function for All Portfolios

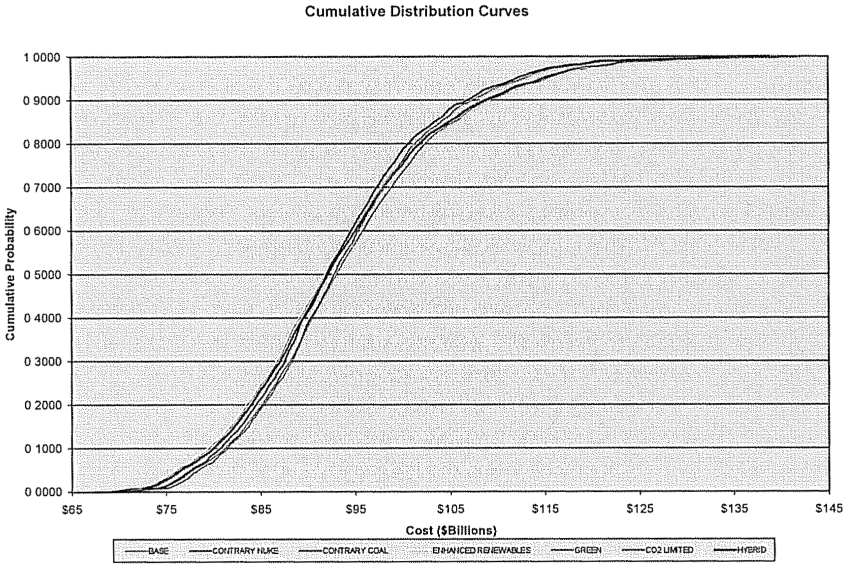
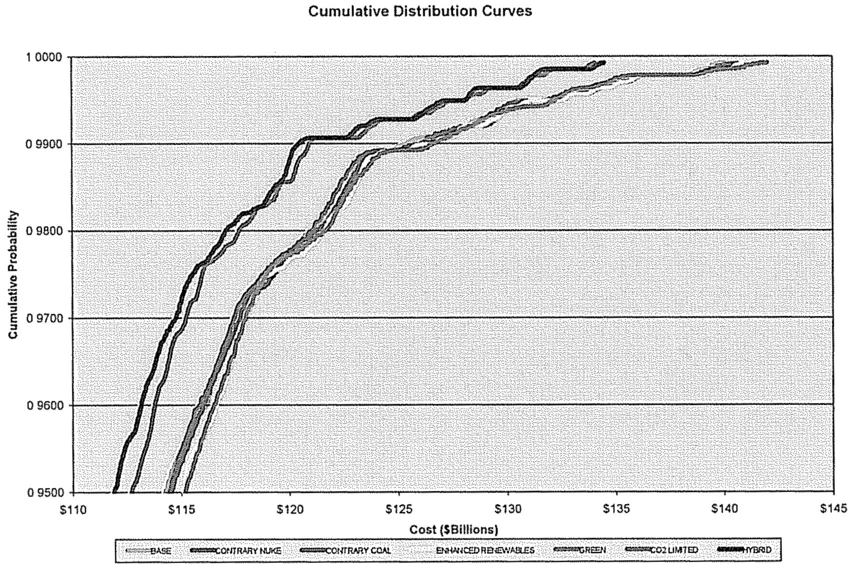


Exhibit T2-7: Distribution Function for All Portfolios at > 95% Probability



2.5 Conclusion From Risk Modeling

The Hybrid Plan had the lowest cost at both the 50% probability level and the 95% probability level. Its RRaR was the second lowest, slightly behind the CO_2 limited plan. Therefore, it can be concluded that the Hybrid Plan is the least, reasonable cost plan across a wide range of potential outcomes.