COMMONWEALTH OF KENTUCKY

BEFORE THE

PUBLIC SERVICE COMMISSION OF KENTUCKY

IN THE MATTER OF:

ADJUSTMENT OF RATES OF	**)**
KENTUCKY POWER COMPANY	**) Case No. 2009-00459**

KENTUCKY POWER RESPONSES TO KIUC
FIRST SET OF DATA REQUESTS

February 26, 2010

Kentucky Power Company

REQUEST

Please provide all work papers and supporting documentation used by Dr. Avera in the preparation of his Direct Testimony and exhibits. Please provide all spreadsheets with cell formulas intact. Please provide all data that support his quantitative analyses.

RESPONSE

Copies of Dr. Avera's workpapers and supporting documentation, including electronic spreadsheets, are provided on the attached CD labeled "Avera WP's and Documentation".

WITNESS: William E Avera

Kentucky Power Company

REQUEST

Please provide copies of all articles, Commission Orders, and all other documents referenced and cited by Dr. Avera in his Direct Testimony.

RESPONSE

Copies of all articles cited in Dr. Avera's direct testimony are included in his workpapers provided on CD in response to KIUC 1st Set, Item No. 1. Copies of all orders from regulatory commissions are publicly available from the respective agencies.

WITNESS: William E Avera

Kentucky Power Company

REQUEST

Please provide copies of all bond rating agency reports (Moody's, Standard & Poor's, Fitch) for Kentucky Power and American Electric Power for the years 2006 through 2010.

RESPONSE

Due to the voluminous nature of the response, the requested information can be found in the CD attached to this set of data requests.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Please provide all supporting information and documentation associated with AEP's 2009 issuance of common stock cited by Dr. Avera on page 48 of his Direct Testimony. Please provide the issuance costs incurred by AEP for this issuance.

RESPONSE

Please refer to the CD for the attachment "AEP 2009 Common Stock Issuance Prospectus.pdf" for supporting documentation regarding American Electric Power, Inc.'s 2009 common stock issuance. Please refer to page S-16 of the Prospectus Supplement for information on underwriting issuance costs.

WITNESS: William E. Avera

Kentucky Power Company

REQUEST

Regarding AEP's 2009 issuance of common stock, please describe the intended use of the proceeds of this issuance.

RESPONSE

Please refer to KIUC 1st Set, Item No. 4, page 14 of 49, USE OF PROCEEDS section.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to Exhibit WEA-9. Please explain why Dr. Avera did not include short term debt in the computations of capital structure for his comparative group.

RESPONSE

Because the facilities employed to provide utility service are long-lived assets, short-term debt is generally not viewed by investors as part of the permanent capital used to finance investment in plant and equipment. Indeed, short-term debt is typically used to meet seasonal working capital needs, and may also be used to finance capital improvements until a sufficient balance has accumulated to economically issue common stock or long-term debt. For most utilities, short-term debt balances fluctuate depending on seasonal or other operating or financial requirements. Because short-term debt outstanding typically fluctuates with seasonal or other operating requirements, the year-end balance may not accurately reflect any permanent reliance on this financing source for the companies in Dr. Avera's proxy group.

WITNESS: William E. Avera

Kentucky Power Company

REQUEST

Please provide a copy of the cost of service model used to develop the Class Cost of Service Study shown in Exhibit DEH-1, in executable electronic format, with all formulas intact and with inputs consistent with the Company's filing.

RESPONSE

Please see response and attachment included in Commission Staff 2nd Set, Item No. 36a.

WITNESS: Daniel E High

Kentucky Power Company

REQUEST

Please provide all workpapers supporting the derivation of the allocation factors developed external to the cost of service model, in electronic spreadsheet format with formulas intact if available.

RESPONSE

Please see response and attachment included in the Company's response to Commission Staff 2nd Set, Item No. 36b.

WITNESS: Daniel E. High

Kentucky Power Company

REQUEST

If not shown in the workpapers previously provided, please provide each of the twelve monthly coincident peaks by rate class used to develop the production allocation factor for the Class Cost of Service Study.

RESPONSE

Please see page 12 of 16 of the workpaper attachment included in the Response to Commission Staff 2nd Set, Item No. 36b.

WITNESS: Daniel E High

Kentucky Power Company

REQUEST

If not shown in the workpapers previously provided, for each class in the Class Cost of Service Study please provide the loss factors used to adjust energy and demand at metered voltage to the various uniform voltage levels used in allocation factors.

RESPONSE

Please see attached three pages.

WITNESS: Daniel E High

Kentucky Power
Current Loss Factors

Test Year Ending: 12/31/2006

Loss Factors by System

System	Total	Fixed	
Demand			
Transmission	0.03935	0.00349	
Subtransmission-Reg	0.01227	0.00239	
Subtransmission-Adj			
Primary Distribution	0.02908	0.00436	See Note 3
Secondary Distribution	0.03155	0.01209	
Energy			
Transmission	0.02781		
Subtransmission-Reg	0.00972		
Subtransmission-Adj			
Primary Distribution	0.02056		See Note 3
Secondary Distribution	0.03297		

Cumulative Loss Factors (Compounded)

System	
Demand	
Transmission	1.03935
Subtransmission	1.05210
Primary Distribution	1.07402
Secondary Distribution	1.10790
Energy	
Transmission	1.02781
Subtransmission	1.03780
Primary Distribution	1.05205
Secondary Distribution	1.08674

Notes:
(1) Updated with results from final MAC study dated 8/13/07.
(2) Cumulative Loss Factors are applicable to load metered at respective system voltages to determine losses back to the generator.
(3) MAC study value taken from Exhibit 8.

KENTUCKY POWER COMPANY

TWELVE MONTHS ENDED SEPTEMBER 30, 2009

LOSS EQUATION VARIABLES

FUNCTIONAL LEVEL	YEAR	MONTH	DATE	HOUR	ANNUAL MAXIMUM	MAXIMUM LOSS AMOUNT	LOSS COEFFICIENT	ZERO LOAD LOSSES
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
SECONDARY	9	1	16	8	1,064,186	34,054	0.000000018794	12,770
PRIMARY	9	1	16	10	1,173,452	34,030	0.000000021304	4,694
SUBTRANSMISSION	9	3	3	8	1,259,008	15,108	0.000000007943	2,518
TRANSMISSION	9	3	3	8	1,581,751	61,688	0.000000022760	4,745
GENERATION	9	3	3	8	1,643,439	0	0.000000000000	0

15:36 Wednesday, December 2, 2009

KENTUCKY POWER COMPANY

TWELVE MONTHS ENDED SEPTEMBER 30, 2009

COMPOSITE LOSS FACTOR SUMMARY

VOLTAGE	METERED		AT GENERATION		LOSS FACTOR TO GENERATION	
	DEMAND	ENERGY	DEMAND	ENERGY	DEMAND	ENERGY
(1)	(2)	(3)	(4)	(5)	(6)	(7)
SECONDARY	760,237	3,796,701,681	837,938	4,162,584,947	1.10221	1.09637
PRIMARY	72,191	516,437,193	76,934	544,651,924	1.06570	1.05463
SUBTRANSMISSION	304,788	2,431,440,317	317,826	2,516,208,580	1.04278	1.03486
TRANSMISSION	41,246	404,637,958	42,571	414,859,333	1.03211	1.02526

VOLTAGE	COMPOSITE LOSS FACTORS: TO SECONDARY		TO PRIMARY		TO SUBTRAN		TO TRAN	
	DEMAND	ENERGY	DEMAND	ENERGY	DEMAND	ENERGY	DEMAND	ENERGY
(1)	(2)	(3)	(4)	(5)	(6)	(7)	(8)	(9)
SECONDARY	1.00000	1.00000	1.03426	1.03958	1.05699	1.05944	1.06792	1.06936
PRIMARY	0.96688	0.96193	1.00000	1.00000	1.02198	1.01910	1.03254	1.02865
SUBTRANSMISSION	0.94608	0.94390	0.97849	0.98125	1.00000	1.00000	1.01034	1.00936
TRANSMISSION	0.93640	0.93514	0.96848	0.97215	0.98977	0.99072	1.00000	1.00000

Kentucky Power Company

REQUEST

Please provide each of Mr. Roush's exhibits DMR-1 through DMR-4 in electronic spreadsheet format, with formulas intact.

RESPONSE

Please see direct testimony of David M. Roush, Exhibits DMR-1 to DMR-4. Also see attached CD for exhibits in electronic spread sheet format.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Please provide all workpapers supporting Mr. Roush's testimony and exhibits, in electronic format with formulas intact if available.

RESPONSE

Please see response to KIUC 1st Set, Item No. 11. Also, please see response and attachment included in Commission Staff 1st Set, Item No. 8c. Also see attached CD for workpapers in electronic format.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Please provide all workpapers associated with the Company's proposed rate design, in electronic format with formulas intact if available.

RESPONSE

Please see the response to KIUC 1st Set, Item No. 12.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

To the extent not provided in response to the previous questions (1 through 7), please provide electronic versions of pages 2 through 61 of the Company's response to Commission Staff 1st Set of Data Requests, Item No. 8-c, with formulas intact.

RESPONSE

Please see the response to KIUC 1st Set, Item No. 12.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

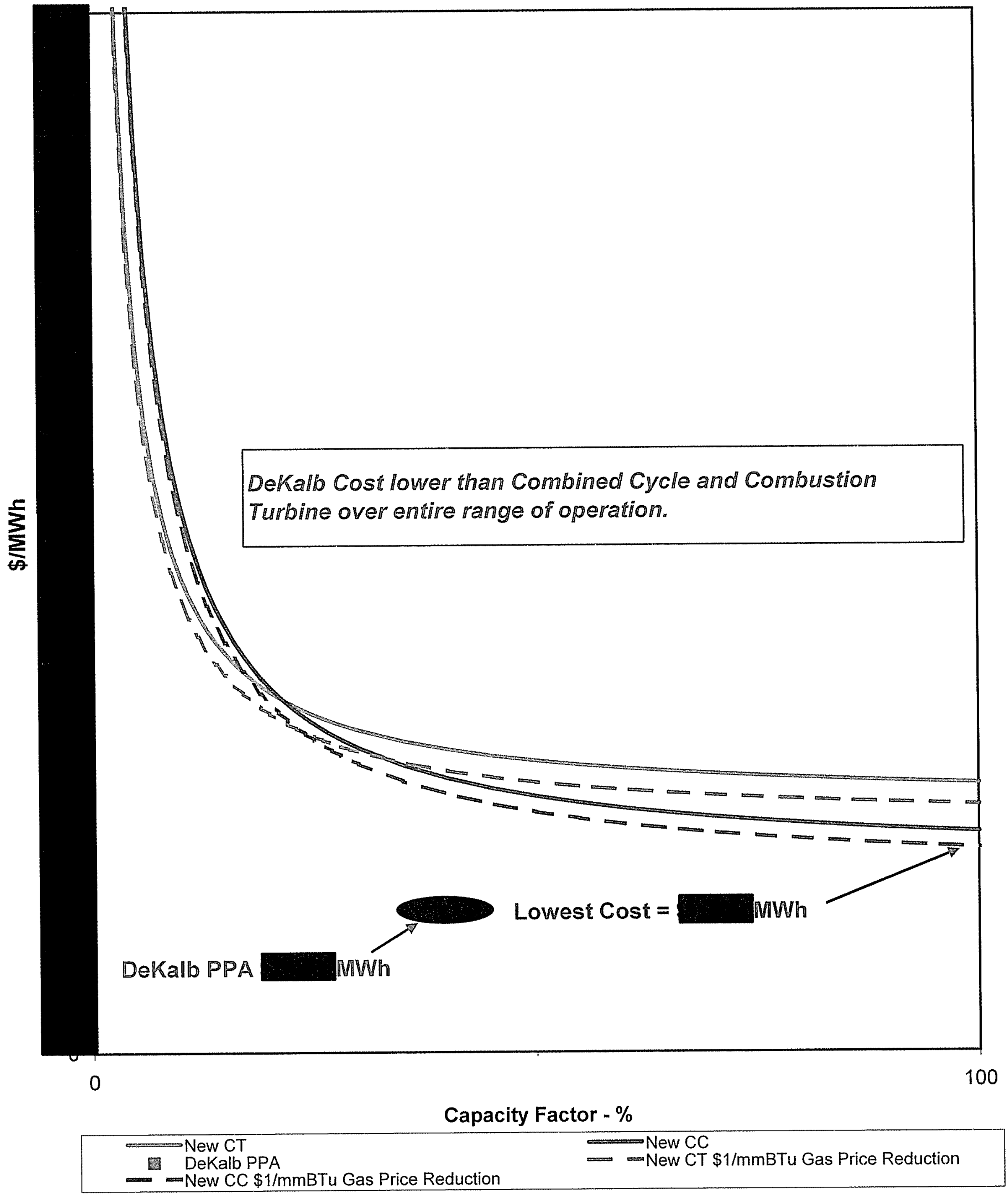
Refer to page 6 lines 15-19 of Mr. Scott Weaver's Direct Testimony wherein he describes the AEP System review of supply-side resource options and consideration of combined cycle and combustion turbine resources. With respect to the proposed wind power purchased power agreement, please provide a comparison of the annual and life-cycle costs of that proposed contract to the most recent least cost bid from a supplier or AEP's most recent cost projection for combined cycle and/or combustion turbine capacity.

RESPONSE

See pages 2 of 3 for a graphical comparison of life-cycle costs of the proposed contract and recent projections for CT and CC capacity, and page 3 of 3 for key assumptions used in developing the CT and CC life cycle costs. Confidential protection of portions of the attachment is being requested in the form of a Motion for Confidential Treatment.

WITNESS: Scott C Weaver

DeKalb vs. New CT & New CC
2010 - 2030 Levelized All-in Cost



AEP SYSTEM-EAST ZONE
New Generation Technologies
Key Supply-Side Resource Option Assumptions (a)(b)(c)

	Capability (MW) (Unforced Capacity)			Installed Cost (d)	Trans. Cost (e)	Full Load Heat Rate	Variable O&M	Fixed O&M	Emission Rates		
Type	Std. ISO	Winter	Summer	($/kW)	($/kW)	(HHV,Btu/kWh)	($/MWh)	($/kW-yr)	SO2 (Lb/mmBtu)	NOx (Lb/mmBtu)	CO2 (Lb/mmBtu)
Intermediate											
Combined Cycle (2X1 GE7FA, w/ Duct Firing)	580	598	545	[redacted]					0.0007	0.008	116.0
Peaking											
Combustion Turbine (4X1GE7FA)	627	652	600	[redacted]					0.0007	0.033	116.0

Notes: (a) Installed cost, capability and heat rate numbers have been rounded.
(b) All costs in 2008 dollars.
(c) $/kW costs are based on Unforced Capacity.
(d) Total Plant & Interconnection Cost w/AFUDC
(e) Transmission Cost ($/kW,w/AFUDC).

Kentucky Power Company

REQUEST

Refer to Exhibit SCW-1A and the capacity of 6 mW indicated for each 50 mW of wind capacity. In addition, refer to Exhibit EKW-18, which indicates a capacity value of 36.5 mW (422,135 – 385,619) for each month during the year.

a. Please reconcile the mW capacity values on Exhibit SCW-1A and Exhibit EKW-18.

b. Please provide a schedule showing the projected monthly capacity value that the Company will be granted by the AEP System for pool capacity. Provide a copy of all source documents relied on for your response.

RESPONSE

a. PJM planning criteria provides that 13% of the nameplate value for new wind capacity may be used for meeting capacity obligations. For a 50 MW block this equates to 6.5 MW. However, for capacity equalization calculations under the AEP Pool, the impact on capacity position for wind projects is equal to (1 - Operating Company MLR) multiplied by the wind project capacity factor, or 36.5 MW.

b. See response to "a." The Company has no reason to believe the AEP Pool value (36.5 MW) will change prospectively.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to Exhibit SCW-3. Please provide the underlying computations for this exhibit, including all assumptions, data and electronic spreadsheets with formulas intact.

RESPONSE

The accompanying spreadsheet provides the requested information. Confidential protection of portions of the attachment is being requested in the form of a Motion for Confidential Treatment.

WITNESS: Scott C Weaver

Kentucky Power Company
Relative Change in Annual Revenue Requirement / Project Cost Comparison
Due to Proposed 100 MW LDWEC PPA
2010-2020

A	B	C	D	E	F	G	H	I	J
	KPCo / LDWEC Wind Capacity (Nameplate)	*KPCo / LDWEC Wind Energy*	LDWEC PPA Cost	<Avoided> Variable Costs, including AEP-Pool Energy Settlements	<Avoided> Pool Capacity Settlement Costs	D+E+F = KPCO (Total Co.) (Net) Revenue Requirement Change re: LDWEC Project (1) (2)	KPCO Internal Load	G / H x 100 = KPCo Relative (Net) Revenue Requirement (3)	*10+ Year Average (2010-2020)*
	MW	*GWh*	($M)	($M)	($M)	($M)	(GWh)	(¢/kWh)	*(¢/kWh)*
		CONFIDENTIAL COMPONENTS							
2010 (5)	*100*	[redacted]				2.8	4,041 (5)	0.070	
2011	*100*					6.4	8,286	0.077	
2012	*100*					6.6	8,354	0.078	
2013	*100*					6.5	8,417	0.077	
2014	*100*					6.2	8,472	0.074	
2015	*100*					6.5	8,530	0.077	
2016	*100*					6.6	8,593	0.076	
2017	*100*					6.2	8,651	0.071	
2018	*100*					5.2	8,707	0.060	
2019	*100*					4.8	8,762	0.055	
2020	*100*					5.4	8,816	0.061	*0.071*

K	L	M
	G x 1000/C =	
	LDWEC (Net) Cost per Mwh of Wind Generated	*versus... Estimated Cost of RECs (4)*
	(per MWh)	*(per ~MWh)*
	CONFIDENTIAL COMPONENTS	
2010 (5)	[redacted]	
2011		
2012		
2013		
2014		
2015		
2016		
2017		
2018		
2019		
2020		

LDWEC Project "Proxy"...
IF FUTURE Wind Contracts (Post-2012) were to exclude 'Pass-thru' of Federal PTCs (@ ~$30/Mwh)

2013	[redacted]
2014	
2015	
2016	
2017	
2018	
2019	
2020	

Notes:
(1) (Net) Revenue Requirement determination excludes the monetization (credit to revenue requirement) of any RECs received under the assumption they would ultimately be required to be utilized/retired to achieve a potential RP
Also, reflects a KPCo 'Total Company' (retail and wholesale) perspective
(2) Assumed if wind PPAs not assigned to KPCo, would be assigned to another AEP (Pool) Member Company, so there would be no incremental MLR-related (Off-System) revenues
(3) As a function of KPCo annual (internal) net energy requirement.
(4) National REC estimates (nominal) per AEP Strategic and Economic Analysis (H209 'SEA' Case)
(5) Assumes PPA start date of July 1, 2010.... therefore for 2010 'Relative (Net) Revenue Requirement' purposes, only Jul-Dec 2010 KPCo Internal Load reflected
(6) Although numerous regional/state REC markets exist *today*, assumes a fungible 'national' REC markets would be established in parallel with passage of a Federal RPS

Column Definitions:
D. LDWEC PPA Cost - represents 3rd-party purchase costs under the 100 MW LDWEC PPA, and based on projected generation profiles for the LDWEC project
E. Variable Cost including AEP-Pool Energy Settlements - primarily fuel costs that are estimated to be offset by wind energy, as well as change in Primary (inter-co) sales to/from AEP Pool cos
F. Pool Capacity Settlement Charges - represents reduced capacity payments to other AEP Member Companies due to the assumed capacity value of PPA assigned to KPCo
H. Net Revenue Requirement Change - is the sum of columns D through F
I. KPCo Relative Net Revenue Requirement - represents the average incremental costs of the LDWEC Project --in cents/kWh-- based on (divided by) KPCo's internal energy requirements
J. Represents the (simple) average (Net) Revenue Requirement impact of the LDWEC Project in cents/kWh over the 2010-2020 period
L. Represents the annual (Net) Cost of the LDWEC project based on (divided by) the corresponding annual estimated wind generated by that project

Net Energy Cost and Requirement - East
Years: 2010;2011;2012;2013;2014;2015;2016;2017;2018;2019;2020
KPCo

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Energy Cost ($000)	[redacted]										
Coal											
Combustion Turbine											
Total											
Plus Receipts: Receipts											
Wind Purchases											
Less Deliveries: Deliveries											
Total Net Energy Cost											
Net Energy Requirement (GWH)											
Coal											
Combustion Turbine											
Total Generation											
Plus Receipts: Receipts											
Wind Purchases											
Less Deliveries: Deliveries											
Total Net Energy Requirement											
Net Energy Cost (M/KWh)											
NEC less wind											
Total NEC diff											
Wind PPA											
Other NEC Diff											
DeKalb PPA GWh											
Wind Purchases (Total Cost x 1.0)											

Net Energy Cost and Requirement - East
Years: 2010;2011;2012;2013;2014;2015;2016;2017;2018;2019;2020
KPCo

		2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
Net Energy Cost ($000)		[redacted]										
Coal												
Combustion Turbine												
Total												
Plus Receipts:	Receipts											
	Wind Purchases											
Less Deliveries:	Deliveries											
	Total Net Energy Cost											
Net Energy Requirement (GWH)												
Coal												
Combustion Turbine												
Total Generation												
Plus Receipts:	Receipts											
	Wind Purchases											
Less Deliveries:	Deliveries											
	Total Net Energy Requirement											
	Net Energy Cost (M/KWh)											
	NEC less wind											

AEP EAST SYSTEM
Capacity Equalization Settlement
($000s)

	2010	2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
‹PCo with Lee-Dekalb wind purchase 7/2010	[redacted]										
‹PCo w/o Lee-Dekalb wind purchase	[redacted]										
mpact to KPCo Capacity Payment:	[redacted]										

Year	Renewable Energy Certificate ($/MWh) - Nominal $'s
2009	[redacted]
2010	[redacted]
2011	[redacted]
2012	[redacted]
2013	[redacted]
2014	[redacted]
2015	[redacted]
2016	[redacted]
2017	[redacted]
2018	[redacted]
2019	[redacted]
2020	[redacted]

Kentucky Power Company

REQUEST

Please provide a copy of all studies performed by or on behalf of the Company that address the revenue requirement effect on the Company of adding additional capacity from new supply-side resources, including, but not limited to, the effect on pool capacity payments. Provide all assumptions, data, computations, and electronic spreadsheets with formulas intact.

RESPONSE

See response to KIUC 1st Set Item No. 17.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please provide a copy of all AEP System guidelines, policies and/or procedures that address the ownership or assignment and sizing of new supply-side resources among the AEP operating utilities, e.g., the ownership and mW of new combined cycle capacity.

RESPONSE

Article 4, paragraph 4.1 of the Interconnection Agreement specifies Members' obligations stating: "Each member shall, to the extent practicable, install or have available to it under contract such capacity as is necessary to supply all of the requirements of its own customers."
In past practice, the assignment of new capacity is to the most deficit Pool member.

There are no guidelines, policies or procedures addressing sizing of new supply side resources. Ownership of new supply side resources is determined by the Operating Committee as described in Article 2 of the Interconnection Agreement.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to the column entitled "Committed Net Sales" and footnote (e) on Exhibit SCW-1A.

a. Please explain why Kentucky Power Company is allocated an MLR share of AEP System capacity sales when it is a short company.

b. Please explain why AEP could not have and did not structure the capacity sales as sales from the long companies rather than allocating such sales on an MLR share.

c. Cite to any specific provisions of the Interconnection Agreement that prohibit the assignment of such sales to the long companies.

RESPONSE

a. AEP-East System capacity sales are AEP-East Pool transactions which are shared by Pool members.

b. System transactions, whether purchases or sales, are established through the AEP Pool. Therefore any revenues or expenses are shared by the member companies on an MLR basis..

c. There is no specific provision in the Interconnection Agreement prohibiting the assignment of such sales to specific member companies.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to page 5 lines 1-2 of Mr. Wagner's Direct Testimony wherein he states with respect to the Interconnection Agreement that it "Requires each member to provide adequate generating facilities (or resources) to meet its firm load requirement." Please explain how the Company's proposed wind power PPA is the optimal and least cost option for the Company to meet its "firm load requirement." Provide all documentation that supports your response.

RESPONSE

See response to KIUC 1st Set Item No. 15 for a comparison of the levelized life cycle costs of this wind PPA to other resource options. Also, as reflected on Exhibit SCW-3, when considering the value of REC's, the wind power PPA is the least cost option. In addition, as described throughout Mr. Weaver's testimony, the wind PPA is part of a strategy to include renewable resources in the KPCo portfolio in anticipation of Federal renewable energy standards and prior to the expiration of Production Tax Credits.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

With respect to the proposed wind power purchased power agreement, does the Company anticipate that the net present value or some portion of the net present value of the future payments will be considered as a long term debt equivalent by the debt rating agencies? If so, please provide the Company's quantification of the debt equivalent amount.

RESPONSE

The company anticipates this power purchase agreement to be considered a non-lease PPA for accounting treatment purposes. Rating Agency treatment depends on the agency.

Standard & Poor's

Standard & Poor's May 2007 report Standard & Poor's Methodology for Imputing Debt For U.S. Utilities' Power Purchase Agreements states the following:

"The pricing for some PPA contracts is stated as a single, all-in energy price. Standard & Poor's considers an implied capacity price that funds the recovery of the supplier's capital investment to be subsumed within the all-in energy price. Consequently, we use a proxy capacity charge, stated in $/kW, to calculate an implied capacity payment associated with the PPA. The $/kW figure is multiplied by the number of kilowatts under contract. In cases of resources such as wind power that exhibit very low capacity factors, we will adjust the kilowatts under contract to reflect the anticipated capacity factor that the resource is expected to achieve.

For the PPA agreement with FPL Energy Illinois Wind, and applying S&P's PPA methodology for debt equivalency, the Company believes the debt equivalent to be approximately $30M using a 25% risk factor.

Moody's

Moody's March 2005 Rating Methodology: Global Regulated Electric Utilities report States the following:

"PPA's have a wide variety of financial and regulatory characheteristics and are thus each particular circumstance may be treated differently by Moody's. The most conservative treatment would be to treat the PPA as a debt obligation of the utility as, by paying the capacity charge, the utility is effectively providing the funds to service the debt associated with the power station. At the other end of the continuum, the financial obligations of the utility could also be regarded as an ongoing operating cost, with no long-term capital component recognized. Factors which determine where on the continuum Moody's treats a particular PPA are as follows: Risk management, Pass-through capability, Price considerations, Excess Reserve Capacity, Risk-sharing, Default provisions.

Each of these factors will be weighted by Moody's analysts and a decision made as to the importance of the PPA to the risk analysis of the utility. According to the weighting and importance of the PPA to each utility and the level of disclosure, Moody's may analytically assess the total obligations for the utility using one of the methods: Operating cost, Annual obligation, NPV, Debt Look-through, Mark-to-Market, Consolidation.

In some circumstances, Moody's will adopt more than one method to estimate the potential obligations imposed by the PPA. This approach recognizes the subjective nature of analyzing agreements that can extend over a long period
of time and can have a different credit impact when regulatory or market conditions change. In all methods the Moody's analyst will account for the revenue from the sale of power bought from the IPP. We will focus on the term to
maturity of the PPA obligation, the ability to pass through costs and curtail payments, and the materiality of the PPA obligation to the overall cash flows of the utility in assessing the affect of the PPA on the credit of the utility".

Fitch

Fitch's Global Power Quarterly report from July 2006 states the following:

"Fitch views power purchase commitments as a component of the operating expense of a utility or merchant energy company, not a debt instrument. As a general policy, Fitch does not adjust the debt of utilities and others in the sector to reflect power purchase obligations as quasi-debt, nor does it impute a portion of long-term purchased power expense as interest expense. In certain relatively rare cases, however, uneconomic contracts may be treated as debt-like obligations (see Debt-Like Contracts section). Also, Fitch has a general corporate policy of capitalizing a debt-like obligation for rental obligations under operating leases".

WITNESS: Errol K. Wagner

Kentucky Power Company

REQUEST

Refer to page 20 line 17 of Mr. Godfrey's Direct Testimony wherein he states: "The 20-year Wind PPA also provides a direct benefit to the consumer." Please confirm that the Company does not claim that there is a net present value benefit to customers compared to the least cost supply side resource available. If the Company cannot confirm this, then please provide all documentation and quantifications that demonstrate that there is a net present value benefit to customers compared to the least cost supply side resource available.

RESPONSE

The comments referred to on Page 20, Line 17 of Mr. Godfrey's Direct Testimony are in regard to the cost advantages of the renewable resource provider being able to procure long-term financing over a 20-year period. There are additional benefits to the consumer that the Lee-DeKalb 20-year PPA provides, such as a hedge against future environmental uncertainty, and the benefits of fuel diversity. The Direct Testimony of Scott Weaver beginning at page 20 line 6 discusses the economic review of the Lee-DeKalb Wind project. Also, please refer to the Response to KIUC 1st Set, Item No. 21.

WITNESS: Jay F Godfrey

Kentucky Power Company

REQUEST

Refer to the column entitled "Avoided Variable Costs, including AEP-Pool Energy Settlements" on Exhibit SCW-3.

a. Please quantify the additional sales margins from sales to AEP sister companies and off-system resulting from the wind power energy in each year of the contract. Provide all assumptions, data and computations of such margins, including electronic spreadsheets with formulas intact.

b. Please provide the additional sales margins from sales to AEP sister companies and off-system resulting from the wind power energy reflected in the Company's test year revenue requirement. Please indicate where the Company included such amount in its filing. In addition, provide all assumptions, data and computations of such margins, including electronic spreadsheets with formulas intact.

c. Please quantify the avoided variable non-FAC expenses due to the wind power energy in each year of the contract. Provide all assumptions, data and computations of such expenses, including electronic spreadsheets with formulas intact.

d. Please provide the avoided variable non-FAC expenses due to the wind power energy reflected in the Company's test year revenue requirement. Please indicate where the Company included such amount in its filing. In addition, provide all assumptions, data and computations of such avoided variable non-FAC expenses, including electronic spreadsheets with formulas intact.

e. Please quantify the avoided variable FAC expenses due to the wind power energy in each year of the contract. Provide all assumptions, data and computations of such expenses, including electronic spreadsheets with formulas intact.

f. Please identify, describe and provide any other avoided variable expenses/costs not considered as sales margins, non-FAC expenses or FAC expenses in each year of the contract. Provide all assumptions, data and computations of such expenses/costs, including electronic spreadsheets with formulas intact.

RESPONSE

a. In accordance with Article 6 of the Interconnection Agreement, the member delivering Primary Energy receives payment equal to its Primary Energy rate. Thus, there are no margins associated with sales to sister companies. Moreover, there will be no incremental off-system sales from wind energy power as explained in Note 2 of SCW-3.

b. See the response to item a. above. There were no adjustments to the test year. Any increased sales as a result of the Wind PPA will flow through the System Sales Clause.

c. There were no variable non-FAC expenses reflected in Exhibit SCW-3.

d. See the response to item c. above. There were no adjustments to the test year for non-FAC expenses.

e. See the workpaper provided in response to Item No. 17, this set.

f. See the workpaper provided in response to Item No. 17, this set.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Refer to Section V Workpaper S-4 page 46. Please confirm that the Company's adjustment 46 shown on this schedule does not include any avoided variable expenses/costs or sales margins from the additional energy. If this is correct, then please explain why it does not. If this is not correct, then please identify where such savings and/or margins are included and provide the amount of such savings and/or margins.

RESPONSE

The intent of this adjustment was to reflect pool capacity savings, not energy (variable expense) savings.

WITNESS: Scott C Weaver

Kentucky Power Company

REQUEST

Please confirm that the Company's adjustment 46 is not for the amount of net expense that will be incurred in 2010 and that the amount included in the test year revenue requirement is an annualized amount. If this is true, does the Company agree that the annualized amount will not be incurred until calendar year 2011? Please explain your response.

RESPONSE

Adjustment number 46 is an annualized amount. The Company expects the annualized amount will be incurred during the first twelve months following the effective date of new rates. The Company expects the expense will be prior to December 31, 2010.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Please identify and describe each incentive compensation program available to AEPSC and Kentucky Power Company employees.

RESPONSE

Due to the voluminous nature of the response, the requested information can be found in the CD attached to this set of data requests.

WITNESS: David A Jolley

Kentucky Power Company

REQUEST

For each incentive compensation plan, please identify which plans payout based on the financial performance of AEP. Identify all financial performance factors and targets established, including all payout matrices, for each such plan and the weighting for each factor.

RESPONSE

Copies of all annual and long-term incentive plans were provided in response to the KIUC 1st Set Item No. 27. Please refer to each plan document for complete descriptions of plan metrics and payout factors.

WITNESS: David A Jolley

Kentucky Power Company

REQUEST

For each incentive compensation plan, please provide the test year expense amount incurred through charges to the Company from AEPSC and incurred directly by the Company for its employees.

RESPONSE

A breakdown of test year incentive amounts by each incentive compensation plan broken down between those charges from AEPSC and directly incurred by Kentucky Power employees is as follows:

Incentive Compensation Plan	Kentucky Power Employees	From AEPSC(a)
Kentucky Power Company	$ 1,142,899	$ 0
Generation	$ 844,526	$ 306,575
Transmission	$ 147,174	$ 276,221
Shared Services	$ 109,826	$ 229,970
Customer & Distribution Services	$ 0	$ 347,375
Long Term Incentive	($ 85,422)	$ 8,157
Sr. Officer	$ 0	$ 117,361(a)
Finance	$ 0	$ 0(a)
Environmental, Safety, Health & Facilities	$ 18,636	$ 0(a)
Corporate Communications	$ 0	$ 0(a)
Corporate	$ 0	$ 475,926
Commercial Operations	$ 0	$ 384,039
Total	$ 2,177,639	$ 2,145,624

(a) Test year AEPSC incentive compensation is funded through monthly accruals which record expense, and offsetting liabilities, based upon monthly estimates of the year end incentive targets. The accrued expense is recorded as a loading on employee labor and is not necessarily segregated by each available plan, but rather is segregated by AEPSC department. The Sr. Officer, Finance, Environmental and Corporate Communication plans are all combined in the monthly accruals.

In responding to this request the Company discovered an error of Exhibit RKW-1 of the Direct Testimony of Ranie K. Wohnhas. The sign was incorrect on the test year incentive amount of KPCo employees under LTIP. A corrected Exhibit RKW-1 is attached as page 3 of this response.

WITNESS: Ranie K Wohnhas

Exhibit RKW-1
Revised 2/12/10

Kentucky Power Company
Summary of ICP/LTIP Adjustment to 1.0 Target Payout
Test Year 12ME 9/30/2009

Type of Incentive	Calculated Incentive @ 1.0 Payout	Test Year Incentive	Adjustment
ICP			
KPCo Employees	$ 2,658,577	$ 2,263,061	$ 395,516
AEPSC Employees	$ 2,992,070	$ 2,137,467	$ 854,603
Total ICP	$ 5,650,647	$ 4,400,528	$ 1,250,119
LTIP			
KPCo Employees	$ 206,705	$ (85,422)	$ 292,127
AEPSC Employees	$ 784,153	$ 8,157	$ 775,996
Total LTIP	$ 990,858	$ (77,265)	$ 1,068,123
Total ICP/LTIP	$ 6,641,505	$ 4,323,263	$ 2,318,242

Kentucky Power Company

REQUEST

Refer to page 9 lines 9-10 of Mr. David Jolley's Direct Testimony wherein he states: "As a result, in any given year, total pay increases will slightly exceed the merit increase budget." Please confirm that this statement addresses only pay "increases" and that it does not address total compensation, which may be more or less and will reflect the composition of the work force, e.g., new lower paid employees that replace higher paid employees that retire or otherwise leave the Company in any year, and the staffing levels of the work force, whether increases or decreases.

RESPONSE

This statement addresses only pay "increases" and does not address total compensation, which may be more or less and will reflect the composition of the work force, e.g., new lower paid employees that replace higher paid employees that retire or otherwise leave the Company in any year, and the staffing levels of the work force, whether increases or decreases.

WITNESS: David A Jolley

Kentucky Power Company

REQUEST

Refer to page 10 lines 8-9 of Mr. David Jolley's Direct Testimony wherein he states: "As a result, overall increases for hourly employees will slightly exceed the general increase in any given year." Please confirm that this statement addresses only "increases" and that it does not address total compensation, which may be more or less and will reflect the composition of the work force, e.g., new lower paid employees that replace higher paid employees that retire or otherwise leave the Company in any year, and the staffing levels of the work force, whether increases or decreases.

RESPONSE

This statement addresses only pay "increases" and does not address total compensation, which may be more or less and will reflect the composition of the work force, e.g., new lower paid employees that replace higher paid employees that retire or otherwise leave the Company in any year, and the staffing levels of the work force, whether increases or decreases.

WITNESS: David A Jolley

Kentucky Power Company

REQUEST

Refer to page 18 lines 13-17 of Mr. Jolley's Direct testimony wherein he addresses the amount of the long-term incentive plan requested by the Company.

a. Please confirm that the $990,858 amount cited is compensation that is "paid" in the form of restricted stock.

b. Please demonstrate that the Company quantified this amount on an expense basis, i.e. that this is not a total amount for both capital and expense. If this amount is a total amount for capital and expense, please provide the expense amount along with all assumptions, data and computations used to compute the expense amount.

RESPONSE

a. The $990,858 amount cited is the estimated dollar value that would be paid to long-term incentive plan participants at a 1.0 payout level. These payments would normally be paid in cash unless a participant elected to defer receipt of the award or the participant was subject to a minimum stock ownership requirement.

b. Please see response to KIUC First Set, Item No. 33.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to Exhibit RKW-1, entitled "Summary of ICP/LTIP Adjustment to 1.0 Target Payout." Please demonstrate that the Company quantified the amounts shown on this schedule on an expense basis, i.e., that this is not a total amount for both capital and expense. If the amounts on this schedule are the combined capital and expense amounts, then please provide a schedule that shows only the expense amounts along with all assumptions, data and computations used to compute the expense amounts.

RESPONSE

The "Total ICP/LTIP" amounts shown on Exhibit RKW-1 are for both capital and expense. These amounts are shown in Section V, Workpaper S-4, Page 13 lines 1,2 and 3. Line 4 then allocates 65.56% of the adjustment to test year incentive plan costs to O&M.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to Exhibit RKW-1. Please provide the workpapers used compute the amounts at a 1.0 payout. Provide the assumptions, data, computations and electronic spreadsheets with formulas intact.

RESPONSE

The workpapers are provided in the attached CD.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 26 lines 12-13 of Mr. Wagner's Direct Testimony. Please provide a copy of the AEP or Company guidelines for the "coal inventory target of days supply to have on hand" of 30 days. Provide a copy of all other source documents relied on for this target level.

RESPONSE

In establishing the coal inventory target for the Big Sandy plant, AEP considers the probability of interruptions of the fuel supply, how long such interruptions may last, and how much fuel is necessary to provide for these contingencies. These targets are established by a cross-functional team, the Fuel Supply Task Group (FSTG), composed of personnel from the generation, commercial operations, fuel procurement, transportation and regulatory groups within AEP. The FSTG performs this analysis annually. The study in place during the test period is attached.

WITNESS: Errol K Wagner

Coal Inventory Worksheet October 24, 2008

A	B	C	D	E	F	G	H	I	J	K	Q	Adder	R	S	T	U	V	W	Z	AA	AB	AC	AD	AE	
Plant	Blend Ratio	Unit(s)	Current Nominal Rating MWe	Fuel	Plant Series Average Heat Rate at Full Load	2008 Avg Btu AR	Heat Input Tons/hr Full Load Burn Rate	Blended Weight Tons/hr Full Load Burn Rate	Tons/Day Full Load Burn Rate	Plant Tons/Day Full Load Burn Rate	Security Level Coal Pile Base [Days]	Remp Tons-Recoverable at Last Resort	Security Level Coal Pile [Tons]	Del and Flex [Days]	Base Load or High CF Plants adder [Days]	Special Targets and Admin Adjust	Normal Days Inventory	Normal Full Load Basis Target Inventory [Tons]	Normal Range up to plus 15 Days Security Coal Pile [Days]	Normal Range up to plus 15 Days Security Coal Pile [Tons]	Winter Adder [Days]	Winter Total Days Inventory	Winter Proposed Full Load Basis Target Inventory [Tons]	Coal Pile Capacity [Tons] (yellow fill, Target is greater than 75% of capacity)	Comments
Big Sandy	100%	1	260	Bituminous	10,264	12,013	111	111	2,666									-							
	100%	2	800	Bituminous	9,550	12,013	318	318	7,632	10,298	15	5,000	159,464	10	6		30	313,928	45	463,393		30	313,928	1,000,000	Multiple truck sources, Added rail capability.

Base = 15 Days for All Plants, which is the "Security inventory"
Delivery and Flexibility = 5 to 20 Days, Based on evaluation of transportation risks, number of fuel sources, etc.
Additional 5 Days Added to High CF/ Base Loaded Plants
Administrative Adjustment - Blending Flexibility - Pandemic Adjustment— Implementation by Approval of the VP Fuel Procurement and Sr. VP FEL
Special Targets - Winter targets plus 15% — Implementation by Approval of the VP Fuel Procurement and Sr. VP FEL

Explanation of Columns in Coal Inventory worksheet

The primary change from past targets is that the calculation of coal inventory targets is based on 24 hour full load burns vs. annual average burns.
There was some tuning from the 2003 Coal Inventory study to reflect past experience and plant equipment changes.

Cols. A, B, C, D, and E – Plant, Unit, Nominal Net Rating, Normal Fuel Type and blend ratio

Col. F – Full load three year Avg heat rate from 2005-2007. Values provided by Barry Rederstorff and Tom McCartney. Sheet 2 of the this spread sheet shows the heat rate for each unit.

Col. G – This is the average Btu in FDR for January-October, 2008.

Cols. H, I, J and K – This is the arithmetic calculation othe full load 24 hour /day burn rate for each coal pile. Blended piles have special blend formula

Cols P, Q, R and S represent the meat of the target development process. The attached Power point presentation describes the methodology that was used to develop the values in these columns.
Column Q is the minimum days inventory for unit security
Column R is the minimum Security tons inventory
Column S is the working inventory
Column T is a safety factor for the base load and largest plants
Column U is a location for administrative adjustments.

Col. U – This catego Column V is the Normal" days storage target and is the sum of Col Q, S, T, and U
Special targets, when implemented are included in Column T

Col W is the calculated "normal" target

Cols Z & AA show the plus side range and maximum inventory that would be expected in the coal pile

Cols. AB, AC, and AD – There is a five day adder for specific plants during the winter period. This adder is further explained in the Power Point attachment.
Winter targets are in effect from November 1 thru March 31

Column AE is the Coal Pile capacity - Highlighted yellow indicates target greater than 75% capacity, red is over.

Plant	Unit	Location	Current Nominal Rating MWs	Fuel	Baseline Heat Rate	BL HR @ CWT	Heat Rate Deviation 3-yr Avg	Adjusted Heat Rate at Full Load
Big Sandy	1	Louisa, KY	260	Bituminous Coal	9,234	90	1030	10264
Big Sandy	2	Louisa, KY	800	Bituminous Coal	9,051	90	514	9550

Kentucky Power Company

REQUEST

Refer to page 26 lines 12-20 of Mr. Wagner's Direct Testimony wherein he claims that "coal inventory is usually financed with short term debt."

a. Please provide all support for this claim, including copies of source documents relied on.

b. On Section V Workpaper S-3 page 2 of 3, the Company's actual short term debt for July, August and September of 2009 was $0. Please explain how the Company financed its coal inventory in those three months, if indeed the statement that "coal inventory is usually financed with short term debt" is correct.

c. On Section V Workpaper S-3 page 2 of 3, the Company's actual short term debt for June 2009 was $6.0 million, substantially less than the imputed $19.995 million in coal inventory in the test year. Please explain how the Company financed its coal inventory in June 2009, if indeed the statement that "coal inventory is usually financed with short term debt" is correct.

d. On Section V Workpaper S-3 page 2 of 3, please identify each rate base amount that was financed by short term debt for each month in the test year. In addition, please provide all support for the Company's response.

e. Please provide the actual coal inventory balance for each month September 2008 through September 2009 in tons and dollars.

RESPONSE

a. In Case Numbers 8429, 8734, 91-066 and 2005-00341 KPCo has consistently reflected adjustments (increase or decrease) in the value of fuel inventory by making an adjustment to the short term debt value at the end of the test year. In Case No. 8429 KPCo proposed an increase its short term debt of $10,939,466 to reflect an equal increase in the value of fuel inventory. The Commission at page eight of its June 18,1982 in that case states "the Commission has reduced Kentucky Power's adjustment [to its short term debt] by $4,108,704 to reflect the lower level of inventory and the weighted average price".

The coal inventory is turned over approximately every 62 days and considering the 32 days supply of inventory above the target level is a temporary level further supports the short term debt adjustment.

The KIUC or its predecessor was a party to the Case No. 8249 proceeding and therefore should have a copy of the relevant documents.

b.Internally generated funds. The adjustment at issue is a temporary run up in coal inventory due to a reduced demand for coal generation. In fact at January 27, 2010 the Company had a coal inventory level of 45 days or a reduction of approximately 53% ((62 days - 45 days)/32 days) of the amount of days supply above the target inventory level in approximately 45.

Funds are not traceable and they are fungible. However, what should be important is consistent treatment of the coal inventory adjustment. Short Term Debt should not be used only when the inventory adjustment is an upward adjustment and when the coal inventory adjustment is a downward adjustment use another method of adjustment.

c. See the Company's response to "b" above.

d. The Company has not performed the requested analysis.

e. Please see Page 3 of 3.

WITNESS: Errol K Wagner

Kentucky Power Company
Fuel Stock - Coal
End of Month Balance Sheet Amounts
From September 2008 To September 2009

Pd	Year	Account	Account Description	End of Month Balance Sheet Amount	Tons
9	2008	1510001	Fuel Stock - Coal	$14,748,657	149,647
10	2008	1510001	Fuel Stock - Coal	$21,779,478	223,227
11	2008	1510001	Fuel Stock - Coal	$29,257,552	316,627
12	2008	1510001	Fuel Stock - Coal	$28,228,487	370,966
1	2009	1510001	Fuel Stock - Coal	$21,134,387	295,675
2	2009	1510001	Fuel Stock - Coal	$21,320,895	302,856
3	2009	1510001	Fuel Stock - Coal	$25,508,280	388,780
4	2009	1510001	Fuel Stock - Coal	$23,758,225	361,340
5	2009	1510001	Fuel Stock - Coal	$28,416,439	439,344
6	2009	1510001	Fuel Stock - Coal	$31,502,280	481,554
7	2009	1510001	Fuel Stock - Coal	$35,295,828	545,730
8	2009	1510001	Fuel Stock - Coal	$38,350,208	587,634
9	2009	1510001	Fuel Stock - Coal	$41,524,414	641,744

Kentucky Power Company

REQUEST

Refer to page 27 lines 5-6 of Mr. Wagner's Direct Testimony wherein he claims that the Company will increase its capital by $9.423 million on average over a three year period.

a. Please identify the referenced three year period. Provide the starting and ending months and years.

b. Please provide the computation of the $9.423 million amount and provide the monthly amounts over the referenced period.

c. Please confirm that the Company does not plan to implement its proposed reliability program unless or until it receives base revenues to recover such costs.

RESPONSE

a. The starting date would be the effective date of the new rates and the ending date would be 36 months after the effective date of the new rates.

b. The annual capital expenditures shown on Section V, Workpaper S-4, Page 41 were assumed to be incurred ratably during the three twelve month periods. For example, in year one, zero expenditures were assumed in month one and a total of $4,720,000 in month twelve. On average the first year there would be an additional capital investment of $2,360,000. Year two the Company would have all of year one's capital investment invested during the second year and half of year two's amount or a total amount of $8,815,000 ($4,720,000 + ($8,190,000/2)). And year three all of year one and two's investment and half of year three or a total amount of $17,150,000 (($4,720,000 + $ 8,190,000) + $8,480,000/2). There would be an average incremental reliability capital investment during the three years of $9,441,667 (($2,360,000 + $8,815,000 + $17,150,000)/3).

c. The Company will provide reasonable and is entitled to receive fair, just and reasonable rates.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to Section V Schedule 3 and Section V Workpaper S-3 page 2 of 3.

a. Please explain why the Company used the September 30, 2009 balance of short term debt and did not use the 13 month average of short term debt on Schedule 3 that it computed on Workpaper S-3. Cite all precedent and/or other authorities relied on for this position.

b. Please provide the Company's balance of short term debt for each month subsequent to September 2009 by type of such debt, e.g., AEP Utility Money Pool, bank borrowings or credit facilities.

c. Please confirm that the Company's financing plans include short term debt.

d. Please provide a copy of the Company's operating and capital budgets, and the resulting budgeted financial statements for calendar year 2010. Provide all assumptions, data, computations and electronic spreadsheets with formulas intact. In addition, provide a copy of all narratives that accompanied such budgets, including presentations to the Company's Board of Directors and/or the AEP Board of Directors.

RESPONSE

a. In case numbers 8429, 8734, 91-066 and 2005-00341 KPCo consistently used the short term debt value at the end of the test year for capitalization purposes . The 13 month average short term debt value on Schedule 3 was computed for the purpose of calculating the average short term debt interest rate during the test year.

The KIUC or its predecessor was a party to most if not all of the above proceedings and should have a copy of the relevant documents.

b. All of Kentucky Power's short-term debt is sourced from the utility money pool. Kentucky Power does not have any bank lines of their own to borrow short-term debt. Month-end balances amounts are as follows:

Month and Year	End of Month Balances
October 2009	$0
November 2009	$0
December 2009	$485,337
January 2010	$805,286

c. Yes. The Company's financing plan does include short-term debt.

d. Please see page 2 for the capital budget and pages 3-4 for the O&M budget and financial statements for calendar year 2010. We are not aware of any narratives or presentations to the Company's Board of Directors and/or the AEP Board of Directors for these budgets.

WITNESS: Errol K Wagner/Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 31 lines 1-8 of Mr. Wagner's Direct Testimony addressing the allocation of the SIA trading margins.

a. Please describe how the SIA trading margins were/are addressed in the System Sales Clause.

b. Please confirm that none of the $12.699 million was recovered through the System Sales Clause. If that is not the case, then please provide the amount that was recovered through the System Sales Clause and provide the quantification of this amount.

RESPONSE

a. The system sales margins at issue were the result of trading activities that occurred between July 2000 through March 2006.

When the trading activities occurred, the margins realized from the activities were reflected in the month of the activities. As a result, the margins were reflected in the System Sales Clause during that month and the ratepayers received their appropriate share according the System Sales Clause.

In December 2009 the Company made an accounting entry to debit Account No. 4491003 (an account not reflected in the System Sales Clause calculations) and a credit to Account No. 2340001.

b. None of the $12,698,791.46 recorded in December 2008 was reflected in the System Sales Clause monthly calculations.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Refer to page 34 lines 13-20 of Mr. Wagner's Direct Testimony addressing the Company's proposed increase to O&M expense of $1.876 million for net temporary investment income and expense.

a. Please identify all precedent for this adjustment in prior Company and/or other Kentucky jurisdictional utilities' rate proceedings.

b. Please describe the source of this interest income and expense to "associated companies," according to the description for account 430 in the FERC USOA. Was it the AEP Utility Money Pool or something else? Please describe.

c. If the net amount in account 430 was related to the Company's investment/borrowing position during the test year, please explain why this interest expense would not be fully reflected in the revenue requirement by including the 13 month average short term debt balance in the capital structure used for the return on rate base?

d. Please provide the interest income by source for each month during the test year.

e. Please provide the interest expense by source for each month during the test year.

RESPONSE

a. The Company did file an adjustment in Case No. 2005-00341 at Section V, Workpaper S-4, Page 18. That Case was a settled case. Also see the Company's response to Staff 2nd Set Item No. 66.

b. The AEP System uses a Corporate Borrowing Program to meet short-term borrowing needs. The Corporate Borrowing Program includes a Utility Money Pool, which funds the utility subsidiaries, including Kentucky Power Company. Kentucky Power Company's participation in the Utility Money Pool provides the Company access to short-term borrowing capacity. When Kentucky Power utilizes the Utility Money Pool to borrow, it incurs an expense for the amount it borrows based on the weighted-average interest rate of the money pool. Conversely, when Kentucky Power is invested in the Utility Money Pool, (i.e. has excess cash), the Company earns investment income for the amount in invests at the weighted-average interest rate of the money pool.

c. Please see the Company's response to Staff 2nd Set Item No. 66.

d. Please see the attached page 3 of 3.

e. Please see the attached page 3 of 3.

WITNESS: Errol K Wagner

Kentucky Power Company

Monthly Period	Account No. 4190005 Interest Income	Account No. 4300003 Interest Expense
Sep-09	$ 3,119	$ 72
Aug-09	$ 3,790	$ 122
Jul-09	$ 114	$ 2,388
Jun-09	$ 11,419	$ 82,885
May-09	$ -	$ 125,170
Apr-09	$ 812	$ 160,794
Mar-09	$ 1,069	$ 190,364
Feb-09	$ 396	$ 202,299
Jan-09	$ -	$ 222,000
Dec-08	$ -	$ 352,811
Nov-08	$ 2,133	$ 314,549
Oct-08	$ -	$ 270,082
Sep-08	$ -	$ 168,841

Note: The source for Account Nos. 4190005 and 4300003 is the Utility Money Pool.

Kentucky Power Company

REQUEST

Refer to page 36 of Mr. Wagner's Direct Testimony.

a. Please identify and describe all other known changes in each AEP utility's capacity position in 2010, including both owned capacity and capacity purchased through PPAs. Provide a copy of the source documents relied on for your response either for such changes or to demonstrate that AEP expects no changes other than those identified by Mr. Wagner.

b. Please identify and describe all other known changes in each AEP utility's capacity position in 2010, including sales of owned capacity and capacity sold through PPAs, such as the expired sale to CP&L. Provide a copy of the source documents relied on for your response either for such changes or to demonstrate that AEP expects no changes other than those identified by Mr. Wagner.

c. Please provide a schedule for the AEP East utilities that shows for each month during 2010 each utility's owned capacity, purchased capacity, sold capacity and capacity sold through PPAs to other utilities by month. Identify and describe the source(s) of the information on the schedule.

RESPONSE

a. For the requested information, please refer to attached page 2 of 2 of this response.

b. There are no additional known changes planned as it relates to sale of capacity.

c. For the requested information, please refer to attached page 2 of 2 of this response.

WITNESS: Errol K Wagner

MEMBER PRIMARY CAPACITY (MW)

As Filed	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010
APCO	6,321	6,321	6,321	6,321	6,321	6,321	6,321	6,321	6,321	6,321	6,321	6,321
CSP	4,841	4,841	4,841	4,841	4,841	4,841	4,841	4,841	4,841	4,841	4,841	4,841
I&M	5,155	5,155	5,155	5,155	5,155	5,155	5,155	5,155	5,155	5,155	5,155	5,155
KPCO	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453
OPCO	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450	8,450
	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220	26,220
Known Changes												
APCO	21											
CSP	9											
I&M	268											
KPCO												
OPCO	9											
	307	0	0	0	0	0	0	0	0	0	0	0
Projeced Changes												
APCO			(10)									
CSP		33										
I&M												
KPCO												
OPCO												
	0	33	(10)	0	0	0	0	0	0	0	0	0

Total Capacity w/ changes	Jan 2010	Feb 2010	Mar 2010	Apr 2010	May 2010	Jun 2010	Jul 2010	Aug 2010	Sep 2010	Oct 2010	Nov 2010	Dec 2010
APCO	6,354	6,354	6,364	6,364	6,364	6,364	6,364	6,364	6,364	6,364	6,364	6,364
CSP	4,858	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825	4,825
I&M	5,431	5,431	5,431	5,431	5,431	5,431	5,431	5,431	5,431	5,431	5,431	5,431
KPCO	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453	1,453
OPCO	8,467	8,467	8,467	8,467	8,467	8,467	8,467	8,467	8,467	8,467	8,467	8,467
	26,563	26,530	26,540	26,540	26,540	26,540	26,540	26,540	26,540	26,540	26,540	26,540

Source - Promod Assumptions Document

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Dec-09	12	Wind Purchase - Partial month @ Grand Ridge
Jan-10	21	Wind Purchase - Partial month @ Grand Ridge
Feb-10	33	Wind Purchase - Beech Ridge
Mar-10	(10)	Amos De-Rate

CSP

Dec-09	8	Wind Purchase - Partial month @ Flowler Ridge 2
Jan-10	9	Wind Purchase - Partial month @ Flowler Ridge 2

I&M

Dec-09	8	Wind Purchase - Partial month @ Flowler Ridge 2
Jan-10	9	Wind Purchase - Partial month @ Flowler Ridge 2
Jan-10	259	CPL contract expiration

OPCO

Dec-09	8	Wind Purchase - Partial month @ Flowler Ridge 2
Jan-10	9	Wind Purchase - Partial month @ Flowler Ridge 2

Kentucky Power Company

REQUEST

Refer to page 38 lines 2-9 of Mr. Wagner's Direct Testimony and to Section V Workpaper S-4 page 14.

a. Please provide the same information for each 12 months ending September 30 period for the last ten years, i.e., 2000 through 2009.

b. Please provide the Handy-Whitman index for each 12 months ending September 30 period for the years 2000-2006.

RESPONSE

a & b. Please see the attached page.

WITNESS: Errol K. Wagner

Kentucky Power company
Big Sandy Plant Maintenance Normalization
Test Test Year Twelve Months Ending 9/30/2009

Ln No (1)	Twelve Months Ended (2)	Twelve Months Expenses (3)	Handy-Whittman Index [1/] (4)	Constant Dollar Index (5)	10 Year Constant Dollar Expenses (6)	Constant Dollar Index (7)	5 Year Constant Dollar Expense (8)
1	September 30, 2009	$13,912,404	540	1.00	$13,912,404	1.00	$13,912,404
2	September 30, 2008	$21,012,448	515	1.05	$22,063,070	1.05	$22,063,070
3	September 30, 2007	$14,209,303	492	1.10	$15,630,233	1.10	$15,630,233
4	September 30, 2006	$12,713,271	463	1.17	$14,874,527	1.17	$14,874,527
5	September 30, 2005	$12,466,039	449	1.20	$14,959,247	1.20	$14,959,247
6	September 30, 2004	$11,201,362	420	1.29	$14,449,757		
[illegible]	September 30, 2003	$16,887,286	412	1.31	$22,122,345		
8	September 30, 2002	$9,175,430	397	1.36	$12,478,585		
9	September 30, 2001	$8,231,090	391	1.38	$11,358,904		
10	September 30, 2000	$13,890,154	372	1.45	$20,140,723		
11	*Total*				$161,989,795		$81,439,481
12	Number of Years Average (L11/10)				$16,198,980		$16,287,896
13	Test Year Steam maintenance Expense				$13,912,404		$13,912,404
14	Adjustment to Test Year Expense				$2,286,576		$2,375,492
15	Allocation Factor - PDAF				0.986		0.986
16	KPSC Jurisdictional Amount (Ln 14 X Ln 15)				$2,254,564		$2,342,235

[1/] Handy-Whittman Total Steam Production Plant
Reference E-2 Line 6 January Index.

Kentucky Power Company

REQUEST

Refer to page 40 lines 14-19 of Mr. Wagner's Direct Testimony addressing the expiration of the 250 mW sale to CP&L by I&M.

a. Is it Mr. Wagner's testimony that there will be no off-system sales margin at all resulting from that 250 mW? If so, please provide all reasons for this assumption.

b. Please provide a computation of the off-system sales margin from this capacity and energy based on sales into PJM if this capacity is not sold to another party through bilateral contract. Provide all assumptions, data and computations, including electronic spreadsheets with formulas intact.

c. Please provide a computation of the off-system sales margin from this capacity and energy if it will be sold to another party through bilateral contract. Provide all assumptions, data and computations, including electronic spreadsheets with formulas intact.

RESPONSE

a. We have no basis for making an assumption about off-system sales resulting from the 250 MW. To the extent that there are any such sales, they will be included in the system sales tracker. It is Mr. Wagner's Direct Testimony that it cannot be predicted with certainty where the energy from the 250 MW of capacity will be allocated. It is possible that the energy from this 250 MW may be allocated internally to it's owner Indiana Michigan Power Company. It is also possible that the 250 MW could be used for primary deliveries to other deficit sister companies. The likelihood of allocation to off-system sales cannot be known at this time.

b. The computation requested has not been performed.

c. The computation requested has not been performed.

WITNESS: Errol K Wagner

Kentucky Power Company

REQUEST

Please provide a schedule showing the amount of off-system sales margins that were retained by the Company through the operation of the System Sales Clause for each month during the test year. Provide the gross margins, amounts recovered through base rates, amounts allocated to customers and amounts retained by the Company for each month. Please provide this information on a "cash" basis and on an "accrual" basis.

RESPONSE

Please see Pages 2 and 3 of this response.

WITNESS: Errol K Wagner

KENTUCKY POWER COMPANY
OFF SYSTEM SALES MARGINS
TWELVE MONTHS ENDED SEPTEMBER 30, 2009
ACCRUAL BASIS OR EXPENSE MONTH

Expense Month :

Line	SYSTEM SALES TRACKER	OCT 2008	NOV 2008	DEC 2008	JAN 2009	FEB 2009	MAR 2009	APR 2009	MAY 2009	JUN 2009	JUL 2009	AUG 2009	SEP 2009	12 Months Total
1	Current Month (Tm) Net Revenue Level (1B + 2B)	1,774,266	586,655	609,875	1,696,041	1,465,118	1,406,753	946,454	859,784	2,396,507	1,961,750	1,972,985	1,670,803	17,346,991
2	Environmental Surcharge Costs Allocated to System Sales	171,454	23,064	239,971	136,999	60,100	77,891	148,762	213,016	234,507	103,278	219,600	104,194	1,732,836
3	Subtotal (Line 1 - Line 2)	1,602,812	563,591	369,904	1,559,042	1,405,018	1,328,862	797,692	646,768	2,162,000	1,858,472	1,753,385	1,566,609	15,614,155
4	Base Month (Tb) Tariff 19-1 Net Reveune Level	950,190	1,258,779	2,025,256	2,661,693	2,236,268	1,732,591	2,706,860	2,365,563	3,101,556	2,658,364	1,660,434	1,497,772	24,855,326
5	System Sales Subtotal (Line 3 - Line 4) Applicable To 70% / 60% Sharing	652,622	(695,188)	(1,655,352)	(1,102,651)	(831,250)	(403,729)	(1,909,168)	(1,718,795)	(939,556)	(799,892)	92,951	68,837	(9,241,171)
6	Customer 70% / 60% Sharing	60%	60%	60%	60%	70%	70%	70%	70%	70%	70%	70%	70%	*66.97%*
7	Customer Share of Increase/(Decrease) in System Sales Net Revenue (Line 5 X Line 6)	391,573	(417,113)	(993,211)	(661,591)	(581,875)	(282,610)	(1,336,418)	(1,203,157)	(657,689)	(559,924)	65,066	48,186	(6,188,763)
8	**Total to the Customer (Line 4 + Line 7)**	1,341,763	841,666	1,032,045	2,000,102	1,654,393	1,449,981	1,370,442	1,162,406	2,443,867	2,098,440	1,725,500	1,545,958	18,666,563

KENTUCKY POWER COMPANY
OFF SYSTEM SALES MARGINS
TWELVE MONTHS ENDED SEPTEMBER 30, 2009
CASH BASIS OR REVENUE MONTH

Line	SYSTEM SALES TRACKER													
	Expense Month :	AUG 2008	SEP 2008	OCT 2008	NOV 2008	DEC 2008	JAN 2009	FEB 2009	MAR 2009	APR 2009	MAY 2009	JUN 2009	JUL 2009	
	Revenue Month :	OCT 2008	NOV 2008	DEC 2008	JAN 2009	FEB 2009	MAR 2009	APR 2009	MAY 2009	JUN 2009	JUL 2009	AUG 2009	SEP 2009	12 Months Total
1	Current Month (Tm) Net Revenue Level	7,069,234	4,017,393	1,774,266	586,655	609,875	1,696,041	1,465,118	1,406,753	946,454	859,784	2,396,507	1,961,750	24,789,830
2	Environmental Surcharge Costs Allocated to System Sales	392,665	319,892	171,454	23,064	239,971	136,999	60,100	77,891	148,762	213,016	234,507	103,278	2,121,599
3	Subtotal (Line 1 - Line 2)	6,676,569	3,697,501	1,602,812	563,591	369,904	1,559,042	1,405,018	1,328,862	797,692	646,768	2,162,000	1,858,472	22,668,231
4	Less: Environmental Surcharge Clause Adjustment Case No. 2007-00276, dated August 19, 2008	119,038	0	0	0	0	0	0	0	0	0	0	0	119,038
5	Subtotal (Line 3 - Line 4)	6,557,531	3,697,501	1,602,812	563,591	369,904	1,559,042	1,405,018	1,328,862	797,692	646,768	2,162,000	1,858,472	22,549,193
6	Base Month (Tb) Tariff 19-1 Net Reveune Level	1,660,434	1,497,772	950,190	1,258,779	2,025,256	2,661,693	2,236,268	1,732,591	2,706,860	2,365,563	3,101,556	2,658,364	24,855,326
7	System Sales Subtotal (Line 5 - Line 6) Applicable To 70% / 60% Sharing	4,897,097	2,199,729	652,622	(695,188)	(1,655,352)	(1,102,651)	(831,250)	(403,729)	(1,909,168)	(1,718,795)	(939,556)	(799,892)	(2,306,133)
8	Customer 70% / 60% Sharing	63.938%	60%	60%	60%	60%	60%	70%	70%	70%	70%	70%	70%	80.27%
9	Customer Share of Increase/(Decrease) in System Sales Net Revenue (Line 7 X Line 8)	3,131,106	1,319,837	391,573	(417,113)	(993,211)	(661,591)	(581,875)	(282,610)	(1,336,418)	(1,203,157)	(657,689)	(559,924)	(1,851,072)
10	**Total to the Customer (Line 6 + Line 9)**	4,791,540	2,817,609	1,341,763	841,666	1,032,045	2,000,102	1,654,393	1,449,981	1,370,442	1,162,406	2,443,867	2,098,440	23,004,254

Kentucky Power Company

REQUEST

Refer to page 33 lines 11-17 of Mr. Wagner's Direct Testimony addressing the need to true-up the fuel clause revenues and fuel clause expenses.

a. Please describe the Company's deferred fuel accounting. In this description, please describe the method used to compute the deferral accounting entries and provide an illustrative example of the journal entries using FERC revenue or expense accounts.

b. Provide the monthly actual FAC and base revenues on a cash basis and accrual basis to recover fuel and purchased power expenses and the fuel and purchased power expense during the test year by FERC expense account on a cash basis and accrual basis and the deferred fuel expense by FERC revenue or expense account. If the revenues and expenses are not reconciled through the deferred fuel revenue or expense account, then please provide a reconciliation and quantify and describe all differences.

c. Please explain why this Adjustment 6 for fuel under (over) revenues to the per books test year revenues amounts is necessary if the Company uses deferred fuel accounting and the deferral is reflected as a reduction or increase in the per books revenues or fuel and purchased power expense for the test year.

RESPONSE

a. The Company's deferred fuel accounting attempts to defer fuel expense from one accounting period to an accounting period when the fuel revenues will be received. Due to the fact that the FAC factor is calculated using the kWh sales in one accounting period and that factor is applied to the kWh sales two months later, there will be either an over or under recovery of the fuel costs (unless the kWh sales in the two accounting periods are the same). This over or under recovery is applied in calculating the FAC factor. However, due to the calculations of the FAC clause mechanism where the FAC factor is calculated using the kWh sales of one accounting period and the factor is applied to the kWh sales two month later there will be either an over or under recovery of fuel costs in any time period unless the kWh sales in the two different accounting periods are the same.

b. Exhibit EKW-4 calculates the over/(under) recovery of fuel cost during the test year ending September 30, 2009. Columns 3 through 9, calculate the monthly fuel costs and columns

11 through 16 calculate the monthly fuel revenues. Column 15 is calculated by taking the current month's billed and accrued kWh (column 11) times the FAC factor (column 13) two months earlier. Because the FAC factor is calculated by using the current month's kWh sales and applied two months later to the then kWh sales there will be an over or under collection of the FAC revenues. That over or under FAC amount is reflected in the FAC calculations, using the then current kWh sales to calculate a new FAC factor. The new FAC factor is applied to the kWh sales two months later still resulting in an over/(under) collections position. In any twelve month period there will most likely be an over or under fuel position, thus requiring an adjustment to the test year revenues. As demonstrated in column 17 (EKW-4) in any one month there can be an over or under recovery of fuel costs.

c. The major portion of the dollar value for Adjustment 6 is the result of the Commission's Orders in Case No. 2007-00522 dated June 12, 2007 and Case No. 2008-00283 dated January 8, 2009.

In Case No. 2007-00522 the Commission authorized KPCo to include $1,057,548 per month of cost incurred in prior periods in the calculation of the FAC factor for the months of August and September 2008. The August and September FAC factors were billed in October and November 2008, thus increasing the monthly FAC revenues above the monthly expenses by approximately $2,115,096 ($1,057,548 X 2).

In Case No. 2008-00283 the Commission authorized KPCo to include $981,697 per month of cost incurred in prior periods in the calculation of the FAC factor for the months of December 2008 through May 2009. The December 2008 through May 2009 FAC factors were billed in February 2009 through July 2009, thus increasing the monthly FAC revenues above the monthly expenses by approximately $5,890,182 ($981,697 X 6).

Due to the fact these FAC revenues are one time nonrecurring revenues, an adjustment of $8,005,278 is required to normalize the test year FAC revenues.

This accounts for $8,005,278 of the $10,989,239 over/(under) recovery of fuel adjustment or a difference of $2,933,961.

If one looks at the twelve months ending November 2009 column 9's total jurisdictional fuel cost is $204,378,422. Column 16's total fuel revenue is $211,955,791 or a difference of $7,577,369. $5,880,182 of that difference is the result of the effect of the Commission's Order in Case No. 208-00283 (981,697 X 6). The revenues associated with the Commission's Order in Case No. 2007-00522 or $2,115,096 ($1,057,548 X 2), which were recovered in months October and November 2009 drop off. The remaining difference is $1,697,187 ($7,577,422 - $5,880,182).

WITNESS: Errol K Wagner

PeopleSoft Financials
JOURNAL ENTRY DETAIL REPORT

Report ID: FIN2001
Bus. Unit: 117 --Kentucky Power Co - Gene
Ledger Grp: ACTUALS --Actual Accounting Information
Ledger: ACTUALS --Actual Accounting Information
For the period 09/01/2009 through 09/30/2009
Source: ALL Journal ID: FA0321% Status: ALL

Line / Account / Dept	Description / Proj / Affiliate	W/O / State/Jurisdict	Reference / Product	Statistics Amt / Cost Comp / Currency	ABM Act / Stat	Subcat / An Type	PC Bus UEntry Event	Cur	Debit	Credit
Journal ID: FA0321	Journal Date: 09/01/2009	Source: ONL--Online Journal Entries					Reversal: R--Reversal			
Status: P--Posted	Posted Date: 09/08/2009									
Description ESTIMATED OVER/UNDER DEFERRED FUEL										
Trans Ref#: REC										
1	Unrecovered Fuel Cost KYPc									
1823063	000001074	G0000117		341	974		WSREG			
11789		KYRET		USD		ACT		USD	1,065,173.00	0.00
2	Unrecovered Fuel Cost KYPC									
1823063	000001074	G0000117		341	974		WSREG			
11789		KYRET		USD		ACT		USD	0.00	241,379.00
3	DEFERRED FUEL REG ADJ KYPCo									
5010005	000001074	G0000117		341	974		WSREG			
11789				USD		ACT		USD	0.00	1,065,173.00
4	DEFERRED FUEL ACCR CUR MO KYPC									
5010005	000001074	G0000117		341	974		WSREG			
11789				USD		ACT		USD	241,379.00	0.00
							Total USD		1,306,552.00	1,306,552.00

KPSC Case No 2009-00459
KIUC 1st Set Data Requests
Order Dated February 12, 2010
Item No. 45
Page 3 of 6

PeopleSoft Financials
JOURNAL ENTRY DETAIL REPORT

Report ID: FIN2001
Bus. Unit: 117 --Kentucky Power Co - Gene
Ledger Grp: ACTUALS --Actual Accounting Information
Ledger: ACTUALS --Actual Accounting Information
For the period 09/01/2009 through 09/30/2009
Source: ALL Journal ID: FA0321% Status: ALL

Line / Account / Dept	Description / Proj / Affiliate	W/O / State/Jurisdict	Reference / Product	Statistics Amt / Cost Comp / Currency	ABM Act / Stat	Subcat / An Type	PC Bus Unit / Entry Event	Cur	Debit	Credit

Journal ID: FA0321 Journal Date: 09/30/2009 Source: ONL--Online Journal Entries Reversal: B--Begin Next
Status: P--Posted Posted Date: 10/06/2009
Description ESTIMATED OVER/UNDER DEFERRED FUEL
Trans Ref#: REC

Line / Account / Dept	Description / Proj / Affiliate	W/O / State/Jurisdict	Reference / Product	Statistics Amt / Cost Comp / Currency	ABM Act / Stat	Subcat / An Type	PC Bus Unit / Entry Event	Cur	Debit	Credit
1	Unrecovered Fuel Cost KYPc									
1823063	000001074	G0000117		341	974		WSREG			
11789		KYRET		USD		ACT		USD	0.00	1,556,838.00
2	Unrecovered Fuel Cost KYPC									
1823063	000001074	G0000117		341	974		WSREG			
11789		KYRET		USD		ACT		USD	760,506.00	0.00
3	DEFERRED FUEL REG ADJ KYPCo									
5010005	000001074	G0000117		341	974		WSREG			
11789				USD		ACT		USD	1,556,838.00	0.00
4	DEFERRED FUEL ACCR CUR MO KYPC									
5010005	000001074	G0000117		341	974		WSREG			
11789				USD		ACT		USD	0.00	760,506.00
							Total USD		2,317,344.00	2,317,344.00

PeopleSoft Financials
JOURNAL ENTRY DETAIL REPORT

Report ID: FIN2001
Bus. Unit: 117 --Kentucky Power Co - Gene
Ledger Grp: ACTUALS --Actual Accounting Information
Ledger: ACTUALS --Actual Accounting Information
For the period 09/01/2009 through 09/30/2009
Source: ALL Journal ID: FA0325% Status: ALL

Line / Account / Dept	Description / Proj / Affiliate	W/O / State/Jurisdict	Reference / Product	Statistics Amt / Cost Comp / Currency	ABM Act / Stat	Subcat / An Type	PC Bus UEntry Event	Cur	Debit	Credit

Journal ID: FA0325 Journal Date: 09/05/2009 Source: ONL--Online Journal Entries Reversal: R--Reversal
Status: P--Posted Posted Date: 08/07/2009
Description DEFERRED FUEL EXPENSE > BASE
Trans Ref#: REC

Line / Account / Dept	Description / Proj / Affiliate	W/O / State/Jurisdict	Reference / Product	Statistics Amt / Cost Comp / Currency	ABM Act / Stat	Subcat / An Type	PC Bus UEntry Event	Cur	Debit	Credit
1	Unrecovered Fuel Cost									
1823063	000001074	G0000117		341	974		WSREG			
11789	KYRET			USD		ACT		USD	1,098,860.00	0.00
2	FUEL COST DEFERRED									
5010005	000001074	G0000117		341	974		WSREG			
11789				USD		ACT		USD	0.00	1,098,860.00
							Total USD		1,098,860.00	1,098,860.00

PeopleSoft Financials
JOURNAL ENTRY DETAIL REPORT

Run Date 02/15/2010
Run Time 10:53:14

Report ID: FIN2001
Bus. Unit: 117 --Kentucky Power Co - Gene
Ledger Grp: ACTUALS --Actual Accounting Information
Ledger: ACTUALS --Actual Accounting Information
For the period 09/01/2009 through 09/30/2009
Source: ALL Journal ID: FA0325% Status: ALL

Line / Account / Dept	Description / Proj / Affiliate	W/O / State/Jurisdict	Reference / Product	Statistics Amt / Cost Comp / Currency	ABM Act / Stat	Subcat / An Type	PC Bus UEntry Event	Cur	Debit	Credit

Journal ID: FA0325 Journal Date: 09/30/2009 Source: ONL--Online Journal Entries Reversal: D--Date
Status: P--Posted Posted Date: 10/06/2009
Description DEFERRED FUEL EXPENSE > BASE
Trans Ref#: REC

Line / Account / Dept	Description / Proj / Affiliate	W/O / State/Jurisdict	Reference / Product	Statistics Amt / Cost Comp / Currency	ABM Act / Stat	Subcat / An Type	PC Bus UEntry Event	Cur	Debit	Credit
1	Unrecovered Fuel Cost									
1823063	000001074	G0000117		341	974		WSREG			
11789	KYRET			USD		ACT		USD	0.00	1,792,412.00
2	FUEL COST DEFERRED									
5010005	000001074	G0000117		341	974		WSREG			
11789				USD		ACT		USD	1,792,412.00	0.00
							Total USD		1,792,412.00	1,792,412.00

Kentucky Power Company

REQUEST

Refer to page 5 lines 20-22 of Mr. Thomas Myers' Direct Testimony wherein he cites the actual OSS margins of $15.290 million for the test year.

a. Please provide all evidence that the actual test year amount either is or is not a "normalized" amount for OSS margins.

b. Please provide the Company's actual OSS margins for calendar year 2009 computed on the same basis as the $15.290 million for the test year.

c. Please provide the OSS margins included in the Company's 2010 budget, including all assumptions, data, computations and electronic spreadsheets with formulas intact used to develop the budget amount.

d. Please identify and quantify all expenses that the Company proposes to share 50% with its customers, other than those expenses that are used to compute the OSS margins.

e. Please confirm that the Company's proposal is to remove 50% of the per books OSS margins in the test year from the revenue requirement through a proforma adjustment to increase O&M expense by $7.645 million.

f. Please explain why the Commission should retain the SSC if the price to do so is 50% of the test year OSS margins in establishing a new baseline.

RESPONSE

a. The system sales margins reported on Section V, Workpaper S-4, Page 26 are the actual level of system sales margins reported for financial purposes, adjusted for known and measurable changes.

b. See the attached.

c. The 2010 budget for KPCo's OSS margins is forecast to be $26.8 million. For the requested information, please refer to attached page 3 of 3 of this response.

d. The Company has not proposed to share 50% of any expenses with its customers, other than those expenses that are used to compute the OSS margins.

e. Incorrect. One-half of the test year value, adjusted for known and measurable changes, is multiplied by an allocation factor of 98.7% to yield a value of $7,545,795.

f. Please refer to the Direct Testimony of Tom Myers. Section III., 'Purpose of Testimony', states that the testimony will describe . . . ."The reasons a modified system sales clause sharing mechanism for OSS margins makes sense, and why it provides a balance of risk and reward, along with appropriate incentives to both the customers and shareholders."
(Myers Direct Testimony page 4, lines 3-5)

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Refer to page 6 lines 8-9 of Mr. Myers' Direct Testimony wherein he states: "The proposed modification provides a level of certainty for customers in the form of an embedded rate credit of $7,645,182. Please describe how the Company's proposed modification provides any more certainty for customers than using the per books test year amount of $15,290,363.

RESPONSE

The increased certainty referred to on page 6 lines 8-9 of Mr. Myers' Direct Testimony is based on a comparison of how the current system sales clause functions versus the Company's proposed system sales clause. The level of certainty for customers created by embedding 50% of the Test Year OSS margins as a rate credit is further explained on page 6 line 9 through page 7 line 1 of Mr. Myers Direct Testimony. Within that passage Mr. Myers states . . . . "Under the current system sales clause, there is no assurance customers will receive the benefit of the test year level of OSS margins." (Myers Direct Testimony, page 6 lines 11 and 12)

Mr. Myers concludes the section by stating . . . "Essentially, the proposed modification eliminates any OSS shortfall effect on KPCo customers by including a reasonable level of OSS margins in base rates." (Myers Direct Testimony, page 6 line 23 through page 7 line 1)

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Refer to page 7 line 24 through page 8 line 2 of Mr. Myers' Direct Testimony wherein he states that the Company's proposal provides "AEPSC with an incentive mechanism to optimize the margins in such a manner that will benefit KPCo customers."

a. Please explain in detail how AEPSC will manage the System's OSS any differently with or without the SSC either in its present form or in the modified form proposed by the Company. Provide all evidence in support of each change in AEPSC management of the System's OSS.

b. Please explain how the SCC either in its present form or in the modified form proposed by the Company provides an "incentive" to optimize the margins so that they will benefit KPCo customers as opposed to simply providing a mechanism to share OSS margins over a baseline between customers and KPCo.

RESPONSE

a. Business decisions regarding how AEPSC will optimize OSS margins are made on an AEP s ystem basis and not on an individual operating company basis. In the event that the company determines that the cumulative weight of all commission decisions in the various jurisdictions does not provide adequate incentive, the company would likely scale back OSS activities such as participation in competitive energy supply auctions. AEPSC has no specific plans to alter the management of the System's OSS based on the outcome of this proceeding, but will evaluate future activities accordingly.

b. The proposed system sales clause provides an incentive to optimize OSS margins so that they will benefit KPCo customers by aligning the interests of both the company and the customer. Because OSS margins would be shared 50/50, both KPCo customers and the company benefit from optimizing those margins. The proposed incentive structure also aligns the interests of both the company and the customer in regards to risk management. Because the company has the daily responsibility to actively manage OSS risks, the incentive structure places the greater exposure on the company. The KPCo customers receive an embedded rate regardless of whether OSS margins reach that level and have no limit on their equal sharing to the upside.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Refer to page 10 lines 21-24 of Mr. Myers' Direct Testimony wherein he states that "for AEPSC to continue to assume the incremental risk necessary to optimize OSS margins, it must be able to continue to participate in the margins created by this activity."

a. Please confirm that AEPSC trades on behalf of the AEP System, not specifically on behalf of KPCo.

b. Please confirm that AEPSC will continue to "optimize" OSS margins on behalf of the AEP System regardless of whether there KPCo has a SSC.

c. Please confirm that AEPSC will continue to "optimize" OSS margins on behalf of the AEP System regardless of whether the SSC is modified so that the Company retains 100% of OSS margins between $7.645 million and $15.290 million.

RESPONSE

a. AEPSC is the agent designated by the AEP East Operating companies, through the AEP East Interconnection Agreement and the AEP System Integration Agreement. As instructed by those agreements, AEPSC coordinates the economic dispatch and operation for the power supply resources for the combined system. In summary, AEPSC operates the AEP System as a pool, not on an individual operating company basis.

b. & c. Please see the Company's response to KIUC 1st Set, Item No. 48 part a.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Please identify all other AEP East utilities that have an SSC or any clause mechanism that allows the utility to retain a portion of the AEP System OSS margin allocated to that utility through the Interconnection Agreement.

RESPONSE

Appalachian Power, Columbus Southern Power, Indiana Michigan Power, Kingsport Power, Ohio Power, and Wheeling Power all have a mechanism that allows the utility to retain a portion of the AEP System OSS margin allocated to that utility through the Interconnection Agreement.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Please identify all changes in AEP System trading activities that were adopted when West Virginia re-established the ENEC for APCo with 100% of the OSS margins inuring to ratepayers. Please describe why each such change was initiated and demonstrate that it was initiated due to the lack of any "incentive" mechanism in West Virginia for APCo.

RESPONSE

There were no changes in AEP System trading activities that resulted from the elimination of OSS margin sharing when the ENEC was reinstated in APCo West Virginia. As stated in KIUC 1st Set, Item No. 48 part a., the Company evaluates OSS activities based on the aggregate incentives on the AEP system.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Is it Mr. Myers' position that AEPSC no longer "optimizes" AEP System OSS margins due to the lack of an "incentive" mechanism in West Virginia? Please explain.

RESPONSE

It is not Mr. Myers' position that AEPSC no longer "optimizes" AEP System OSS margins due to the lack of an "incentive" mechanism in West Virginia. In addition, please refer to the Company's response to KIUC 1st Set, Item No. 48 part 'a' and KIUC 1st Set, Item No. 51.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Please confirm that AEPSC will continue to "optimize" OSS margins on behalf of the AEP System regardless of whether KPCo has an SSC.

RESPONSE

Please refer to the Company's response to KIUC 1st Set, Item No. 48 part 'a' and KIUC 1st Set, Item No. 49 part 'a'.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Please confirm that AEPSC will continue to "optimize" OSS margins on behalf of the AEP System regardless of whether the Commission adopts the Company's proposed modification to the SCC.

RESPONSE

Please refer to the Company's response to KIUC 1st Set, Item No. 48 part 'a' and KIUC 1st Set, Item No. 49 part 'a'.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Refer to page 17 line 20 to page 18 line 7 of Mr. Myers' Direct Testimony wherein he provides a list of the AEPSC technology investments and staffing requirements necessary for AEPSC to engage in trading and other activities that generate OSS margins. Please confirm that AEPSC costs to engage in OSS, including investment costs and the operating expenses such as salaries and benefits, are allocated entirely to KPCo and the other AEP utilities and none of these costs are retained by AEPSC.

RESPONSE

AEPSC does not retain any of the costs related to the activities that generate OSS margins. All AEPSC costs are allocated to the AEP operating companies, including KPCo.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Please confirm that the Company does not propose a 50% sharing of the AEPSC costs to engage in OSS, including the investment costs and the operating expenses such as salaries and benefits, and that the entire allocation of these costs to KPCo in the test year are included in the revenue requirement. If this is not the case, then please explain and quantify all such costs that the Company has not included in their entirety.

RESPONSE

The Company has not proposed a 50% sharing of KPCo's portion of the AEPSC costs to engage in OSS, including the investment costs and the operating expenses such as salaries and benefits. KPCo's allocation of these costs in the test year are included in the revenue requirement.

WITNESS: Thomas M. Myers

Kentucky Power Company

REQUEST

Refer to line 12 of Exhibit DMR-1 page 3 of 3. Please provide the fuel and purchased power expense component of the amount on this line and all other expenses separated into function and operation and maintenance expenses where such expenses are functionalized by account. Show the non-A&G 900 series of accounts as a separate category and the A&G expenses as a separate category and by account if such information is available.

RESPONSE

The available detail is shown on Exhibit DEH-1, page 5 and 6, and totals $455,994,177. The amount shown on Section V, Workpaper S-4, Page 45, Line 2, Column (3) of $2,128,351 is deducted, resulting in the value of $453,865,828. That is the correct value instead of the amount of $453,834,609 as shown on Exhibit DMR-1, Page 3, Line 12.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to page 10 line 21 of Mr. Everett Phillips' Direct Testimony and the claim of "increasing customer expectations." Is this a general observation that customers always want better customer service or reliability or is there some specific evidence that Mr. Phillips relies on that customers are demanding better customer service or reliability? If the latter, then please identify all such evidence that customers are demanding better customer service or reliability that Mr. Phillips relied on for this statement.

RESPONSE

The results provided in testimony are the result of one question included in the surveys conducted with 200 residential and 200 commercial customers by third-party vendor MSI in 2008. In addition, please refer to the response to Staff 2nd Set Item No. 45 for the 2008 MSI survey report.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to page 10 line 22 of Mr. Everett Phillips' Direct Testimony and the claim that the Company has a "deteriorating distribution system." Is this a general observation that all equipment and systems deteriorate over time and require replacement and maintenance or is there some specific deterioration that is outside the normal wear and tear? If the latter, then please identify all specific deterioration that is outside the normal wear and tear.

RESPONSE

Company witness Phillips explains the deteriorating distribution system beginning on line 12 of page 11 of his direct testimony. The deterioration to which Mr. Phillips refers to is the deterioration in reliability as represented by the increasing SAIDI metric from 2005 through the end of the test year. This is illustrated in Mr. Phillips Direct Testimony at page 12, Figure 2.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

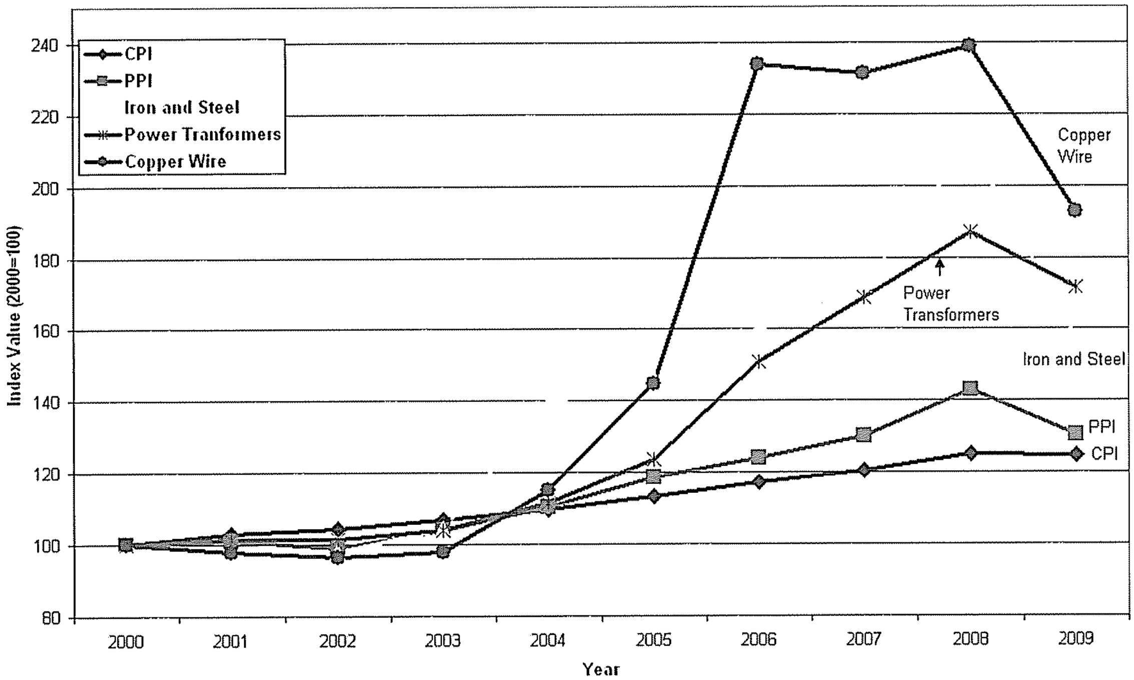
Refer to page 11 lines 12-14 of Mr. Phillips' Direct Testimony wherein he states that "Reliability will become increasingly difficult to improve or even maintain unless KPCo implements a Reliability and Service Enhancement Plan which will require additional funding." Please provide all evidence relied on by Mr. Phillips for this statement, particularly the claim that maintenance of existing reliability will be difficult to maintain without additional funding.

RESPONSE

The test-year level of vegetation management work and expenditures for asset programs will help maintain the level of tree- and equipment-related outages for a short period of time. However, at the same level of expenditures, work will start to decrease as the Company faces inflationary costs associated with material (herbicides, equipment, etc.) and contract labor, which will ultimately result in fewer trees being trimmed and removed, fewer cutouts being replaced, and, inevitably, more service-related outages. One of the examples noted above can be exemplified in the graphic on the following page of this response. Since the year 2000, commodity prices for items like copper, iron, and steel have increased dramatically. Although commodities declined in 2009, commodity escalation is approximately 39 percent greater than general inflation (CPI) over the same time period.

WITNESS: Everett G Phillips

Annual Consumer Price Index (CPI)/Producer Price Index (PPI) vs.
Select Electric Utility Commodities and Equipment



All Data Extracted from United States' Bureau of Labor Statistics Website
Data Extracted January 21, 2010

Kentucky Power Company

REQUEST

Refer to page 13 lines 12-18 of Mr. Phillips' Direct Testimony and the claim that a cycle based program will increase reliability compared to the existing performance-based approach and the claim that the cycle based approach involves "evaluating KPCo's entire distribution system within a four year period."

a. Provide all evidence that a cycle based program will increase reliability compared to a performance based approach relied on by Mr. Phillips.

b. Please confirm that under a performance based approach, KPCo evaluates its entire distribution system on a continuous basis to plan and prioritize the location and scope of its vegetation management work activities. If this is not the case, then please explain why it is not.

RESPONSE

a. Please see the Company's response to Attorney General's 1st Set Item No. 32.

b. Under the performance-based approach, the entire distribution system is analyzed on a regular basis using those items identified by Company witness Phillips at page 8 of his Direct Testimony.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to page 14 lines 1-3 of Mr. Phillips' Direct testimony. Is it true that the existing performance based approach is not "systematic" and "data-driven?" Please explain.

RESPONSE

No. The Company disagrees with the statement that the Company's current performance-based approach to vegetation management is not systematic or data-driven. Company witness Phillips identifies the data driving the performance-based approach currently used beginning on line 7 of page 8 of his testimony, which include "the time elapsed since vegetation management activities were last performed; the results of recent line inspections; tree-related reliability performance; critical customer service needs such as fire stations, police departments and hospitals; and environmental conditions." This data is systematically reviewed in order to "allocate resources to particular circuits, or portions of circuit" as stated on line 12 of page 8.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Please provide a copy of all written policies and guidelines that describe and/or control the Company's existing performance based approach to vegetation management.

RESPONSE

Please see the attached copy of the AEP Forestry Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance Operations.

WITNESS: Everett G Phillips

AEP AMERICAN® ELECTRIC POWER

AEP Forestry

Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance Operations

May 14, 2009

Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance

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AEP System Forestry Guidelines

Foreword

A. Introduction

The purpose of these AEP Forestry Guidelines is to document and inform AEP employees and its contractors of important criteria, practices and procedures pertaining to initial vegetation clearing for construction projects and the maintenance of rights of way. AEP incorporates these guidelines into each tree service contract; a copy shall be kept in all vegetation management contractor's vehicles. These guidelines are for the sole and exclusive use of the contractor and are to be read consistently with other contract documents by and between AEP and the Contractor.

B. Definitions

Brush: Woody stem vegetation less than four (4) inches DBH.

Clearing: The physical cutting and/or removal of woody stem vegetation within the right of way.

DBH: (Diameter at Breast Height). The diameter of a tree measured at the height of 4-1/2 feet above the ground on the uphill side.

Danger Tree: A tree considered a potential hazard to AEP's facilities positioned outside of the normally cleared right-of-way.

Debris: Non-vegetative material such as pop bottles, cans, wire, paper and old tires.

Directional Pruning: The reduction of a tree's crown in a manner that provides increased conductor clearance by pruning to direct growth of the upper crown away from the conductors.

Fallen Tree: A tree lying on the ground not cut by the Contractor.

Hanger: A limb cut from a parent stem or bole of a tree as part of the line clearance pruning procedure left aloft caught and held by the other branches of the tree.

Hazard Tree: A tree considered a potential threat to the safety and reliability of AEP's facilities growing within the normally maintained right-of-way.

Log: The merchantable portion of a tree as designated by AEP.

Lopping: The cutting of limbs and slash so that they lie in contact with the ground or as otherwise designated by AEP.

Mowing: The mechanical cutting of woody stem vegetation within the right-of-way.

Prescription: The plan prepared for each circuit or unit of work. It designates the vegetation to be maintained, the method(s) of maintenance, and who will perform the work.

Removal: The complete cutting down of trees at or near the ground line. AEP shall specify the disposal method.

Slash: The un-merchantable portion of a tree as designated by AEP.

Tree: Woody stem vegetation greater than four (4) inches DBH.

I. Contractor Guidelines

A. Safety

1. Protecting the safety of the public is of utmost importance to AEP. Contractors shall regard safety as their first priority. Contractors and their employees will recognize and follow all laws, rules and regulations regarding public and worker safety. Any safety related incidents (e.g., personal injury, vehicle accident, outages, flashes, near miss, customer issues, etc.) that occur on the job must be reported to the appropriate AEP personnel as soon as possible.

2. All contact incidents outages or operations caused by contract crews shall be reported to the appropriate AEP Dispatch center and Forestry immediately.

B. Personnel

1. If required by state or local laws and regulations the contractor shall have an ISA Certified Arborist available.

2. No private work may be solicited or worked by Contractor employees while on AEP time. Contractors shall not receive compensation from anyone except AEP for tree work that is a part of AEP's Forestry program. The consequences will be crew and/or contractor disciplinary action.

C. Equipment

1. Contractors shall provide sufficient equipment in working order to operate their business.

2. The minimum number of chain saws on the job shall equal the number of personnel on the crew, or as per contract agreement. Chainsaws shall not be billed separately unless approved by AEP Forestry personnel.

3. Each climber shall be provided with a complete set of equipment including: rope, saddle, chainsaw, pruner and handsaw. Each tree crew shall be properly equipped so that, if necessary, a tree rescue can be performed.

   The use of spurs/climbers/hooks should be avoided. Where their use is necessary (as in the removal of some trees or in climbing trees, which do not provide a notch in which to tie in) only qualified persons shall be permitted to use them.

D. Overtime

Overtime is billable for work performed outside the scope of the normal work schedule.

E.. Work Procedures

1. Contractor practices shall be compliance with applicable industry standards (e.g., ANSI, OSHA, NESC) whenever practical unless the use of such standards increases the risk of injury or property damage.

2. Changes in the workweek due to inclement weather, equipment breakdowns or other circumstances must have prior approval by AEP Forestry personnel.

3. The contractor will be responsible for the development of a plan to complete the assigned tasks. The assigned tasks must be performed in a systematic way that follows this plan. Some examples are: beginning work at substations, working between protection devices, or other methods to prevent inefficiency and/or skipped work. The plan must meet AEP approval before work begins.

4. It is the Contractor's responsibility to ensure that the plan is followed, including time estimates to complete the assigned tasks.

5. Contractor shall provide daily work locations to AEP, including changes to these locations throughout the workday.

6. Each crew shall have a planned worksheet at all times, except in the case of emergency work.

7. The Contractor's daily association with their crews and customers will allow planned outages and refusals to be worked on a progressive basis. A written list of such areas that have not been worked, including reasons, shall be supplied to AEP Forestry personnel. Undocumented skips may be worked at the Contractor's expense.

8. Contractor's work shall be inspected on an ongoing basis. When an assigned task is complete, the Contractor must notify AEP Forestry for final inspection.

9. The Contractor will notify AEP of any hazardous conditions found during the performance of work under this contract. This is to include danger trees, soil erosion, and any attachment to AEP's facilities,

deteriorated, damaged or broken facilities and any other abnormal conditions.

F. Public Relations

Public relations are important to AEP. Proper notification can eliminate most property owner issues before they arise. Advanced notification provides the property owner/resident with an opportunity to voice concerns.

1. Where required, an attempt will be made to contact property owners through personal notification, door hangers, news releases, letters, etc. AEP will attempt to contact an absentee landowner only if the landowner provides AEP with a method to contact the landowner.

2. During emergency work, Contractor will attempt to notify the property owner/resident of the crew's arrival. Discretion should be used during late night or early morning work. If no personal contact is made, a door card may be left to explain the emergency work performed.

3. Contractor will document all locations where door cards were left, including address and date. A monitored local or toll-free telephone number to reach the contractor should be on each card.

G. Refusals

1. A "refusal" is considered any property owner/resident refusing to allow or permit the contractor to manage vegetation as specified within the scope of, and according to, these guidelines and all applicable specifications, permits and easements.

2. The contractor shall fill out a refusal/complaint form with all pertinent information for all refusals.

3. If the contractor is unable to resolve the refusal within one week, the refusal shall be turned over to the appropriate AEP Forester.

4. Undocumented refusals or those left unaddressed for more than one week by the contractor may be worked at the Contractor's expense.

H. Damage Claims and Complaints

1. The contractor shall be responsible for all damage claims and complaints due to its negligence. AEP shall be notified immediately of all claims and complaints.

2. An on-site investigation with the resident/ property owner shall be made as soon as possible. This meeting, or telephone arrangements for the investigation, shall be made within twenty-four (24) hours of receipt of the complaint. AEP's representative may accompany the Contractor during this initial investigation.

3. All valid claims resulting from the Contractor's negligence shall be settled within thirty (30) days by the Contractor, or the Contractor shall provide evidence he is trying to reach a reasonable settlement.

4. The Contractor shall keep AEP informed of the status of all complaints. When a settlement is reached, a written release for both AEP and the Contractor shall be obtained from the property owner/resident.

5. If a settlement cannot be reached, the Contractor shall confirm in writing to AEP the final settlement offer and briefly summarize events pertaining to the offer.

6. After thirty (30) days, if a Contractor fails to resolve a claim, does not continue attempts to resolve the claim or keep AEP fully informed, AEP may settle the claim and bill the Contractor.

7. Costs to restore outages or repair the Owner's facilities due to negligence may be billed to Contractor as determined by AEP Forestry.

II. Performance Guidelines

A. Removals

1. Stumps shall be flush cut (three (3) inch maximum height) and treated with an approved herbicide, unless designated otherwise by AEP Forestry.

2. Tree removal shall be completed in one operation. If this is not practical, hazardous conditions shall not be left while the work is not actively in progress. Trees shall be removed in a manner to protect yards, fences, houses, electric lines and other facilities.

3. Targets for removal are:
   - All trees with the potential of growing into the conductors.
   - Trees where adequate clearance cannot be obtained using proper pruning practices.
   - Trees that will take less than three times the amount of time to remove as they would take to prune.
   - Trees within five (5) feet of poles.
   - Mature trees where more than 50% of the crown must be removed to obtain clearance.
   - Young vigorously growing trees where more than 66% of the crown must be removed to obtain clearance.
   - Palm species.

4. Trees that may be less suitable candidates for removal are:

   - Those that would take more than three times longer to remove than to prune for proper clearance and at least 50% of the crown would be left intact.
   - Species that will not reach a height that would affect the conductors.
   - Slow-growing tree species.

5. Deciduous stumps shall be flush cut (three (3) in. maximum height) and shall be treated with an appropriate herbicide to prevent re-growth unless the situation prevents application according to label instructions, there is a documented customer refusal or an AEP forester directs otherwise.

6. At the request of the property owner/resident diseased, dying, or dead trees which could threaten AEP facilities will be "made safe", allowing for removal by the customer or private arborist. Generally, all brush and wood generated by this activity should be left on site, unless otherwise directed by AEP Forestry.

B. Pruning

1. Contractor practices should be compliance with all applicable industry standards (i.e., ANSI, OSHA, NESC) whenever practical unless the use of such standards increases the risk of injury or property damage.

2. Pruning shall be done in a manner that protects current tree health and with regard for future growth and development.

3. Pruning shall provide at least the minimum specified clearance from electrical conductors as set forth in Tables I and II.

4. Reasonable care should be exercised to prevent the spreading of insects or diseases from one tree to another.

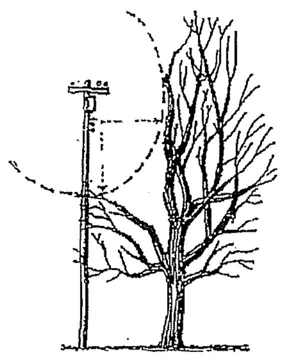
5. Portions of wild cherry, black walnut and other vegetation toxic to livestock (i.e., wilted leaf material) that has been pruned, cut or damaged by the contractor's activities, should be removed from active pasture areas accessible to livestock, unless agreed to by the property owner.

C. Clearances - Distribution

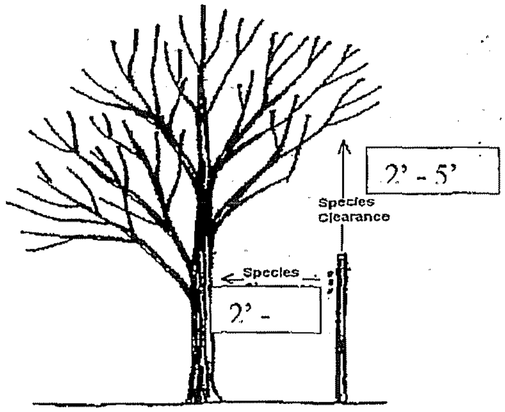
Variances to this recommendation may be necessary and applied due to specific operating company guidelines or specific restrictions in permits and/ or easements.

Minimum clearance for distribution system lines is that distance that will prevent re-growth into any AEP conductors for a minimum of three (3) years (see Table I in the appendix). The species, site, limb and conductor sag and sway during windy conditions and the effect of electrical load should all be considered when determining the clearance requirement.

1. Primary Conductors- Limbs should be pruned for a minimum of three (3) years clearance. Overhanging limbs should be removed. Top of tree should be-directionally pruned unless prior arrangements have been made with the appropriate AEP Forestry representative.



2. Open Wire Secondary Conductors- Limbs should be pruned for two (2) to five (5) feet of clearance without removing overhanging branches unless otherwise specified by an AEP Forestry representative.



3. Twisted, Cabled Secondary, Service Drops or Street Light Conductors -
Trees near twisted or cabled secondary service drops and street light wires will not be pruned unless limbs are applying pressure to the line. Do not prune for street light illumination except under the specific direction of the appropriate AEP Forestry representative.

4. Span Guy Wires – Trees near span guys should only be pruned of heavy limbs applying pressure on the wires.

5. Poles and down guys - All poles and down guys will be cleared of all volunteer trees, brush, and slash to obtain a minimum of a five (5) foot radius of clearance around the pole or guy.

6. Vines - Should be cut, but not removed from AEP or other facilities, and treated with ~~an~~ herbicide to prevent re-growth. Pulling / removing vines may damage equipment and endanger the employee.

D. Clearances - Transmission

The ultimate goal of vegetation maintenance is to provide for the safe, reliable operation of the AEP transmission system. When performing maintenance, the objective for locations on spans with less than 100' vertical clearance at maximum sag from conductor to ground is removal of all woody-stemmed vegetation to the appropriate width, leaving the cleared area of the right of way populated with grasses and herbaceous growth. Under certain circumstances (unique topographic and/or environmentally sensitive conditions), AEP may allow compatible, low-growing species to remain in the right of way. In maintained areas (mowed yards, lawns and public areas), trees deemed compatible with safe operation of the line may remain, although AEP strongly discourages this practice. Compatible species will be limited to those that grow no more than 15' tall or actively maintained trees that could be considered a crop such as in nurseries or orchards.

Clearance Table Guidelines

Right of Way No Restrictions	Right of Way with Restrictions
< 100' Vertical Clearance between Conductors at Maximum Sag and Ground	**< 100' Vertical Clearance between Conductors at Maximum Sag and Ground**
1) *Remove All Woody Stemmed Vegetation* *	1) *Trim or Remove Vegetation to Meet Column C* *
2) Do Not Allow Vegetation Closer than Column E	2) Do Not Allow Vegetation Closer than Column E
3) Trigger Distance to Schedule Maintenance per Column D	3) Trigger Distance to Schedule Maintenance per Column D
> 100' Vertical Clearance between Conductors at Maximum Sag and Ground	**> 100' Vertical Clearance between Conductors at Maximum Sag and Ground**
1) Trim or Remove Vegetation to meet Column B *	1) Trim or Remove Vegetation to Meet Column C *
2) Do Not Allow Vegetation Closer than Column E	2) Do Not Allow Vegetation Closer than Column E
3) Trigger Distance to Schedule Maintenance per Column D	3) Trigger Distance to Schedule Maintenance per Column D

* Upon Completion

1. Restrictions - When removal of all woody-stemmed vegetation is not achievable (i.e. there are restrictions), AEP will endeavor to cut or trim so that upon completion of the work no vegetation will be closer to conductors at maximum sag than the distances outlined in -Columns A and C. Distances are based on completed work meeting or exceeding the minimum approach distances to energized conductors for persons *other than qualified* line-clearance arborists and qualified line-clearance arborist trainees (Columns A and C).

2. Minimum Approach - Additional maintenance should be scheduled when vegetation will encroach within the minimum approach distances from energized conductors for *qualified* line-clearance arborists and qualified line-clearance arborist trainees (Columns A and D). In areas where easement or other legal agreements, or regulations restrict vegetation management practices, the maximum allowable amount of vegetation will be removed or otherwise controlled. AEP will annually monitor locations where these clearances cannot be achieved. The monitoring will determine whether maintenance that is more frequent may be required in order to assure the safe, reliable operation of the circuit.

E. Hangers and Clean Up

1. All hangers should be removed from the pruned tree before leaving the job site.

2. Work sites shall be left in a neat and orderly condition.

3. A minimum amount of clean up work should be performed, especially when a property owner requests a tree be removed. Unless otherwise designated by AEP Forestry, wood shall not be cut up or hauled away. Where designated by AEP Forestry, chipping the brush, cutting wood into lengths that can be handled and raking the site is the maximum clean up that should be performed.

4. All streams and/or drainage ditches shall be kept free of any limbs or woody debris cut by the contractor. Any cut debris that inadvertently falls into such an area, or any debris left in an area that may be prone to regular flooding, shall be moved/removed in an appropriate manner (chipped, stacked on top of ditch bank, etc.)

F. Clearing and Re-clearing

1. AEP Forestry will provide the width of the right-of-way.

2. All woody plants that have the potential to grow into the lines should be controlled, either by removal, herbicide treatment or a combination of both. On distribution lines and areas approved by Transmission Forestry on transmission lines those woody plants within the right-of-way that at mature size normally would not threaten lines or interfere with access to AEP's facilities, should be left undisturbed in the right-of-way whenever possible. Variances to this recommendation may be applied due to specific operating company guidelines.

3. During scheduled maintenance operations, prune or remove any vegetation within the rights-of-way of station entrances or exits that may affect the safe operation of AEP facilities, including station fences and equipment.

4. During scheduled maintenance operations, any vegetation adjacent to station facilities that may affect the safe operation of those facilities should be brought to the attention of the appropriate AEP personnel.

5. Trees, brush, and existing stumps within the right-of-way shall be cut as close to the ground as practicable, but not to exceed three (3) inches in height above the ground line. Where possible, the cut shall be parallel to the slope and promptly treated with an approved herbicide, unless otherwise directed by AEP Forestry.

6. Trees shall be felled to avoid damage to crops, fences and other facilities. Any trees felled into crops, ditches, streams, roads or

across fences shall be promptly removed. No trees shall be felled in such a manner as to endanger AEP's facilities or the property of third parties, or hinder access along the right-of-way.

7. Tree, brush and slash shall be lopped as designated by AEP Forestry.

8. Danger trees are identified and addressed / worked at the discretion of the individual operating companies or regions. Consideration for danger tree removal shall be made for those trees that are an imminent hazard or threat to AEP facilities. Danger trees may include, but are not limited to, trees that have severe lean or sweep, are dead, or have visible defect or damage. When cut, danger trees shall be cut as low as possible.

8. Stumps of trees growing in fences may be cut at fence post height, as approved by AEP Forestry.

9. Logs may be left in tree lengths or as designated by AEP Forestry. If so designated, the merchantable value of logs shall be preserved as much as practical.

10. In remote areas, brush and logs may be piled at the edge of the right-of-way for wildlife habitat.

11. Brush should not be left in managed agricultural areas or other maintained areas unless designated by AEP Forestry.

G. Herbicide Applications

1. All woody plants that have the potential of growing into the lines, should be controlled. Those woody plants within the right-of-way that at mature size normally would not threaten lines or interfere with access to AEP's facilities should be left untreated in the right-of-way whenever practical.

2. Contractors are required to maintain accurate and up to date records of all herbicide applications made and are required to abide by all Federal, State, and local laws concerning licensing, record keeping, and product handling.

3. Contractors shall attain 100% coverage and 95% control of treated vegetation.

4. AEP Forestry will make vegetation management prescriptions in consultation with contractors.

5. Where required, landowners should be notified before any herbicide treatments occur. There are several acceptable methods of *notification such as personal* contact, letter, or door hanger.

6. Managers of public rights-of-way involved in the treatment area shall be notified, where appropriate.

7. Contractor shall be responsible for training of herbicide applicators.

8. Unless specifically prohibited by property owners or AEP Forestry, stumps should be treated with an appropriate herbicide treatment.

H. Tree Growth Regulator Application

1. Trees designated for tree growth regulation shall be treated with an approved tree growth regulator (TGR) in accordance with label instructions.

2. All trees shall be inspected by the Contractor for health and vigor prior to treatment. Trees found in an excessive state of decline shall not be treated unless directed by AEP Forestry.

3. As designated by AEP Forestry, landowners should be notified before any TGR treatments occur. There are several acceptable methods of notification such as personal contact, letter, or door hanger.

APPENDIX I

Distribution Line Clearance Guidelines

These growth rates and clearance distances are guidelines for the minimum clearances required. These distances are not static and should serve as ***minimum clearance*** requirements unless designated otherwise by AEP Forestry. Good soils and high moisture may cause many species to grow faster. These clearance guidelines are not meant as a requirement for all trees on AEP's rights-of-way. It is understood that during maintenance intervals, trees may encroach into these minimum clearance zones. The guidelines are meant to be used a guide for trimming those trees currently being maintained.

MINIMUM CLEARANCE FROM CONDUCTORS

– ***Species with Fast Re-growth Rates: Prune*** for a *minimum* clearance of 20 feet from conductors

Cottonwood	Willow
Poplar species	Ailanthus
Silver maple	Box Elder
Sycamore	

– ***Species with Medium Re-growth Rates:*** Prune for a *minimum* clearance of 15 feet from conductors

Locust	Hackberry
Red maple species	Hickory
Ornamental pear species	Crabapple
Fruit trees (apple, pear, etc.)	Red oak
Elm species	Ash species
Pine, Spruce & Hemlock species	Mulberry
Sweet gum	Bois d'arc (Osage orange, hedge tree)
Catalpa	

– ***Species with Slow Re-growth Rates:*** Prune for a *minimum* clearance of 10 feet from conductors

Cedar	
Chinaberry	Persimmon
Magnolia	White oak (round lobes)
Any small variety species	(Redbud, dogwood, etc.)

– ***Possible Exceptions:***

- When the entire trunk of a tree falls within the minimum clearance specifications.
- When due to the branching structure of the tree less trimming would lend itself to an overall healthier tree, yet with acceptable clearance.
- Isolated instances approved by AEP Forestry representative.

Goals, Procedures & Guidelines for Distribution and Transmission Line Clearance

APPENDIX II

Transmission Line Clearance Guidelines(7)

Column A Nominal Voltage (kV phase to phase)	Column B(5) NERC Clearance 1 (no restrictions) Desired Clearance between Conductor(1)(2) and Vegetation	Column C (3)(5) NERC Clearance 1 (with restrictions) Desired Clearance between Conductor(1) and Vegetation	Column D (3) ANSI Clearance between Conductor(1) and Vegetation	Column E(4) NERC Clearance 2 between Conductor(1) and Vegetation
765 kV	45'	35' 00"	27' 04"	14' 0"
500 kV	45'	26' 08"	19' 00"	10' 0"
345 kV	30'	20' 05"	13' 02"	7' 6"
230 kV	30'	16' 05"	7' 11"	5' 2"
161 kV	25'	14' 00"	6' 00"	3' 5"
138 kV	25'	13' 02"	5' 02"	2' 11"
88 kV & 115kV	25'	12' 04"	4' 06"	2' 6"
69 kV	25'	10' 09"	3' 09"	2' 6"
46kV, 40kV, 34.5 kV & 23 kV	20'	10' 00"	2' 09"	2' 6"

(1) Conductor at maximum sag condition(6)
(2) Desired clearance to maintain reasonable clearing cycles
(3)ANSI Z133.1 rev. 10/2000
(4)IEEE Standard 516-2003, Section 4.2.2.3, Tables 5 and 7, calculated clearances (Clearance 2)
(5)Application of herbicides will be considered as meeting these guidelines, as long as all treated vegetation meets or exceeds the desired clearance from maximum sag (Table AEP1.2, Columns A and C).
(6)AEP Guideline for Determining Maximum Conductor Sag and Blowout for Vegetation Management is to be used to adjust the conductor's found field condition to the maximum sag condition taking into account the conductor size, span length, elevation, and current temperature.
(7)(Columns A, B, C, and D) distances exceed clearances for NERC operationally significant circuits noted in NERC Standard FAC-003-1, which gives clearances (Columns A and E) to be maintained between vegetation and conductors under all rated electrical operating conditions, per IEEE Standard 516-2003 (Guide for Maintenance Methods on Energized Power Lines) and as specified in its Section 4.2.2.3, Minimum Air Insulation Distances without Tools in the Air Gap.

Kentucky Power Company

REQUEST

Please provide all cost benefit studies performed by or on behalf of the Company in support of its proposed enhanced vegetation management plan.

RESPONSE

No cost benefit studies were performed by or on behalf of the Company.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to page 30 lines 18-20 of Mr. Phillips' Direct Testimony. Please provide the following information for KPCo's distribution workforce:

a. Age of each employee and an age distribution.

b. Date of hire and employee level (position) hired in at for each employee.

c. Present employee level (position)

d. Employee level position sequence from lowest level to highest level.

RESPONSE

(a) For the requested information, please refer to attached page 2 of 7 of this response.

(b) For the requested information, please refer to attached page 2 of 7 of this response.

(c) For the requested information, please refer to attached pages 3 through 7 of this response.

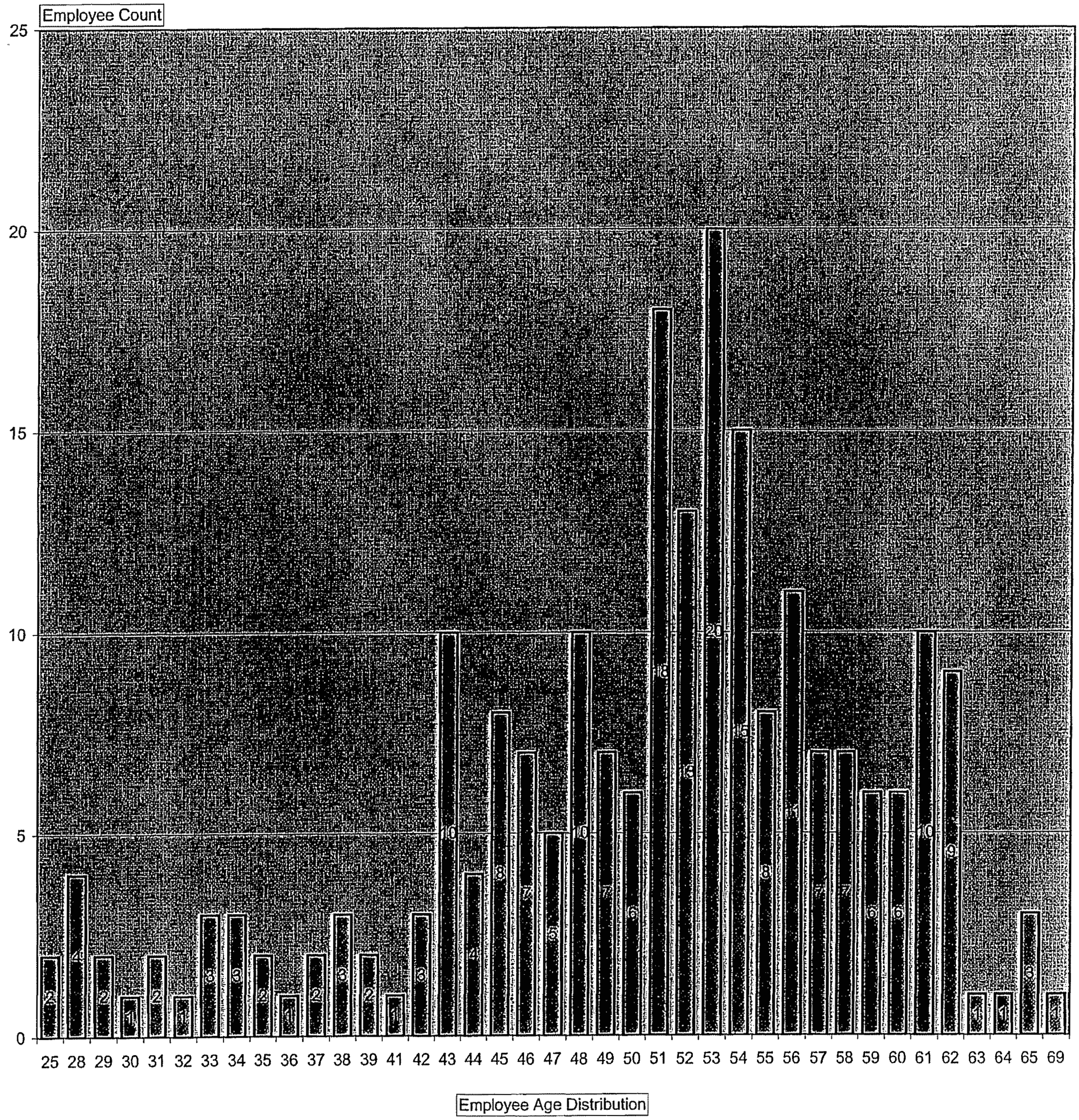
(d) The employee level position sequence for line mechanics starts at entry level of line mechanic (LM) D, progressing to LM C, then to LM B, and finally to LM A (journeyman). Time and skill assessments are required for each position. A LM D will train with existing crews and attend classes for a minimum of one year before progressing to a LM C. A LM C position requires two years in the position before being promoted to a LM B. Finally, a LM B will be in the position for two years before moving to a LM A. Therefore, a line mechanic hired with limited skills will require five years to become a top A line mechanic or journeyman provided the individual has met the skill assessments. General servicer and line crew supervisor positions are filled from the LM A pool of employees, but are not automatic progressions. The general servicer and line crew supervisor positions are filled on an as needed basis depending on customer base, work density and crew complements.

The engineering positions are filled with professional employees hired from accredited colleges and universities into entry level exempt positions, but do not progress at assigned times. Rather, they progress as their knowledge of the electrical system advances to the point that warrants advancement. This usually requires a minimum of five years.

The majority of the other positions listed on the attached document are support positions that are hired based on skill sets with no set level of position sequence. While the majority of employees are hired at entry level positions, they progress over varying times to more senior positions.

WITNESS: Everett G Phillips

Age of Each Employee and Age Distribution



ate of Hire	Employee Level Position Hired in At	Current Position	Current Age
11/19/2007	Utility Forester III	Utility Forester III	31
01/22/2001	Meter Reader	Meter Utility Tester	43
12/04/1979	Technician Senior	Distribution Projects Coordinator	50
06/01/1988	Manager Community Affairs	Customer Services Account Representative Sr	58
08/13/1979	Customer Services Specialist	Field Revenue Specialist	52
07/28/2006	Line Mechanic-D	Line Mechanic-C	37
04/30/1979	Line Mechanic-A	Line Mechanic-A	51
03/28/2005	Line Mechanic-B	Line Servicer	32
03/08/1978	Line Crew Supervisor - NE	Line Crew Supervisor - NE	58
04/14/1980	Line Area Servicer	Line Servicer	54
04/13/1976	Servicer X	Line Mechanic-A	59
03/28/2005	Line Mechanic-B	Line Servicer	36
01/31/1980	Meter Reader	Technician Senior	50
07/05/1996	Line Mechanic-A	Line Mechanic-A	45
09/17/1979	Line Mechanic-A	Line Servicer	52
08/11/2008	Administrative Associate I	Administrative Associate I	47
05/13/1976	Line General Servicer	Line Servicer	59
07/03/1996	Line Mechanic-A	Line Servicer	41
10/18/1976	Line General Servicer	Line Servicer	53
09/05/1990	Line Mechanic-A	Line Servicer	48
08/17/1973	Line Crew Supervisor - NE	Line Crew Supervisor - NE	61
04/22/2007	Line Mechanic-D	Line Mechanic-C	35
02/21/1978	Technician Senior	Technician Senior	51
8/31/1987	Distribution Dispatcher II	Distribution Dispatcher I	54
5/09/1990	Meter Reader	Distribution Dispatcher III	46
07/29/1985	Distribution Dispatcher II	Distribution Dispatcher I	53
05/01/1980	Utility Forester I	Sr Utility Forester	57
10/05/1995	Sr Customer Solutions Associate	Administrative Associate	60
12/16/1980	Distribution Line Coordinator	Resource Analyst I	48
10/01/1975	Supervisor Customer Services I	Reliability Manager	59
06/21/1982	Senior Clerk	Administrative Associate	52
02/16/1998	Meter Reader	Meter Reader	47
04/10/1989	Technician Senior	Technician Senior	46
08/06/1984	Line Mechanic-A	Line Crew Supervisor - NE	44
10/19/1970	Line Crew Supervisor - NE	Line Crew Supervisor - NE	62
02/10/1976	Line Area Servicer	Line Servicer	56
09/01/1981	Line Mechanic-A	Line Crew Supervisor - NE	53
02/12/2001	Meter Reader	Meter Reader	44
04/23/2007	Administrative Associate II	Administrative Associate II	60
08/19/1980	Meter Reader	Field Revenue Specialist	49
07/20/1982	Line Mechanic-A	Line Mechanic-A	49
08/14/1990	Line Mechanic-A	Line Mechanic-A	43
08/05/1976	Line Crew Supervisor - NE	Line Crew Supervisor - NE	61
02/25/1982	Technician Senior	Technician Senior	54
04/21/1981	Technician Senior	Technician Senior	51
09/05/1978	T & D Clerk-A	Administrative Associate	50
03/11/1974	Customer Services Account Representative II	Customer Services Account Representative II	62
04/04/1992	Intermediate Clerk	Administrative Associate	51
2/13/1976	Supervisor Distribution System	Supervisor Distribution System	54
6/25/1980	Line Crew Supervisor - NE	Line Crew Supervisor - NE	59
12/10/1980	Line Mechanic-A	Line Mechanic-A	49
08/31/2006	Line Mechanic-D	Line Mechanic-C	28
02/23/1987	Line Mechanic-A	Line Mechanic-A	51
09/05/2006	Line Mechanic-D	Line Mechanic-C	25
11/20/2006	Engineer III	Engineer III	30

...te of Hire	Employee Level Position Hired in At	Current Position	Current Age
04/24/1978	Transmission Dispatcher I	Distribution Dispatcher I	56
06/03/1968	Utility Forester I	Utility Forester I	63
04/14/1986	Technician Senior	Right Of Way Agent-Distribution	46
01/03/1967	Supervisor Field Services	Supervisor Field Services	65
09/26/1980	Senior Clerk	Administrative Associate	65
01/05/1998	Line Mechanic-B	Line Mechanic-A	38
10/02/2006	Line Mechanic-D	Line Mechanic-C	35
01/14/2008	Meter Utility Tester	Technician II	28
07/01/1985	Customer Services Account Representative I	Customer Services Coordinator I	61
07/25/1978	Meter Reader	Field Revenue Specialist	51
10/31/1977	Line General Servicer	Line Servicer	54
09/11/2006	Line Mechanic-D	Line Mechanic-C	34
07/21/1975	Supervisor Field Services	Supervisor Field Services	56
11/13/1991	Line Mechanic-A	Line Mechanic-A	42
08/19/1975	Line General Servicer	Line Servicer	55
10/09/1975	Line General Servicer	Line Servicer	59
08/12/1975	Line General Servicer	Line Servicer	58
03/20/1989	Line Mechanic-A	Line Mechanic-A	46
05/20/1980	Line Mechanic-A	Line Mechanic-A	48
10/19/1976	Line General Servicer	Line Servicer	55
08/01/1988	Superintendent Region Dispatching	Dispatch Supervisor I	48
01/16/1978	Customer Services Specialist	Field Revenue Specialist	57
02/16/2004	Meter Reader	Meter Reader	47
ˀ4/30/1981	Line Mechanic-A	Line Mechanic-A	51
3/29/1978	Line Crew Supervisor - NE	Line Crew Supervisor - NE	57
07/27/2006	Line Mechanic-D	Line Mechanic-C	31
05/11/1981	Line Mechanic-A	Line Mechanic-A	53
02/21/1989	Line Mechanic-A	Line Crew Supervisor - NE	43
07/06/2004	Meter Reader	Line Mechanic-B	29
01/09/1974	Technician Senior	Technician Specialist	56
07/16/1990	Distribution Line Coordinator	Supervisor Field Services	43
01/10/1974	Line Crew Supervisor - NE	Supervisor Distribution System	57
06/05/1978	Line Mechanic-A	Line Servicer	53
12/09/1983	Line Mechanic-A	Line Mechanic-A	45
12/27/1983	Line Mechanic-A	Line Mechanic-A	48
04/20/1977	Line Crew Supervisor - NE	Line Crew Supervisor - NE	53
10/28/1975	Line Crew Supervisor - NE	Line Crew Supervisor - NE	53
09/10/2006	Line Mechanic-D	Line Mechanic-C	38
02/23/1976	Technician I	Technician Senior	54
11/15/1985	Supervisor Distribution System	Manager Customer & Distribution Services	47
11/22/1976	Technician Senior	Technician Specialist	62
10/11/1984	Meter Reader	Meter Servicer	62
12/19/1983	Meter Electrician-B	Meter Electrician-A	52
02/04/1980	Line Mechanic-A	Line Mechanic-A	51
02/22/1978	Line Crew Supervisor - NE	Line Crew Supervisor - NE	51
07/01/1996	Line Mechanic-A	Line Mechanic-A	48
03/14/1988	Line General Servicer	Line Servicer	54
08/22/2006	Line Mechanic-D	Line Mechanic-C	25
ˀ9/06/1988	Meter Reader	Technician II	43
,6/23/1980	Supervisor Meter Services	Supervisor Meter Services	51
07/27/1981	Meter Reader	Meter Reader	60
01/14/1980	Technician Senior	Technician Senior	52
03/29/2005	Line Mechanic-B	Line Mechanic-A	39
09/15/1985	Manager Community Affairs	Manager Customer & Distribution Services	51
08/03/1977	Engineer I	Senior Engineer	55

ate of Hire	Employee Level Position Hired in At	Current Position	Current Age
05/26/1977	Technician Senior	Technician Senior	53
04/22/1980	Meter Reader	Meter Reader	56
06/27/1973	Customer Services Specialist	Field Revenue Specialist	57
01/30/1978	Senior Clerk	Customer Services Account Representative IV	51
03/06/1978	Line General Servicer	Line Servicer	56
12/05/1980	Line Crew Supervisor - NE	Line Crew Supervisor - NE	51
07/08/1996	Line Mechanic-A	Line Mechanic-A	44
02/20/1980	Line Mechanic-A	Line Mechanic-A	51
06/16/1971	Administrative Secretary	Administrative Associate	61
12/15/1980	Meter Reader	Meter Servicer	51
02/23/1998	Meter Reader	Meter Reader	54
04/08/1985	Meter Reader	Meter Reader	61
06/25/1984	Meter Electrician-A	Meter Electrician-A	53
05/27/1980	Customer Services Specialist	Field Revenue Specialist	58
11/18/1985	Line Mechanic-A	Line Mechanic-A	48
08/12/1976	Line Crew Supervisor - NE	Line Crew Supervisor - NE	53
05/21/1990	Line Mechanic-A	Line Mechanic-A	52
03/19/1979	Technician Senior	Technician Senior	62
05/21/1984	Operations Support Analyst	Distribution Line Coordinator	60
02/23/1998	Trainer II	Distribution Dispatcher III	37
06/13/1996	Line Mechanic-B	Distribution Dispatcher II	34
06/22/1976	Senior Engineer	Manager Region Support	56
11/19/2007	Utility Forester III	Utility Forester III	28
12/27/1978	Technician Senior	Technician Specialist	56
07/10/1973	Distribution Line Specialist	Distribution Line Coordinator Sr	61
03/16/1978	Line Crew Supervisor - NE	Supervisor Distribution System	53
05/16/1990	Line Mechanic-A	Line Mechanic-A	54
07/29/1996	Line Mechanic-A	Line Mechanic-A	34
04/12/1976	Servicer X	Line Mechanic-A	61
12/09/1991	Line Mechanic-A	Line Servicer	56
12/05/1994	Technician Senior	Technician Senior	46
03/12/1979	Meter Electrician-A	Meter Electrician-A	51
02/01/1977	Meter Reader	Meter Reader	58
02/20/1975	Senior Clerk	Administrative Associate	54
09/07/1977	Technician Senior	Technician Senior	52
01/08/1980	Line Mechanic-A	Line Mechanic-A	56
12/30/1968	Line Crew Supervisor - NE	Line Crew Supervisor - NE	62
05/22/1980	Line Crew Supervisor - NE	Line Crew Supervisor - NE	51
04/03/1980	Line General Servicer	Line Servicer	50
09/09/2006	Line Mechanic-D	Line Mechanic-C	33
01/02/1996	Lead Customer Solutions Associate	Administrative Associate	52
06/04/1973	Engineer I	Engineer I	60
04/21/1986	Meter Reader	Meter Reader	56
08/20/1976	Meter Electrician Supervisor-NE	Meter Electrician Supervisor-NE	53
12/06/2004	Administrative Associate I	Administrative Associate	55
12/02/1980	Line Crew Supervisor - NE	Line Crew Supervisor - NE	49
06/12/1996	Line Mechanic-A	Line Mechanic-A	43
03/29/2005	Line Mechanic-B	Line Mechanic-A	39
11/09/1978	Technician Senior	Technician Senior	59
12/26/1968	Distribution Line Coordinator	Distribution Line Coordinator Sr	65
03/15/1976	Transmission Dispatcher I	Distribution Dispatcher I	53
02/01/1979	Distribution Dispatcher II	Distribution Dispatching Coordinator Sr	53
01/17/2005	Meter Reader	Distribution Dispatcher III	33
12/03/1979	Customer Services Engineer III	Manager Customer & Distribution Services	54
04/01/1974	Meter Electrician-A	Meter Electrician-A	55

ate of Hire	Employee Level Position Hired in At	Current Position	Current Age
05/29/1979	Customer Services Specialist	Field Revenue Specialist	52
01/05/1976	Special Clerk	Administrative Associate	61
01/04/1988	Customer Services Engineer III	Customer Services Engineer II	45
06/05/1986	Line Mechanic-A	Line Mechanic-A	53
06/13/1978	Line Mechanic-A	Line Mechanic-A	60
07/26/2006	Line Mechanic-D	Line Mechanic-C	33
02/25/1982	Supervisor Distribution System	Line Mechanic-A	58
02/12/2001	Meter Reader	Field Revenue Specialist	45
12/19/1983	Meter Reader	Meter Reader	48
02/29/1988	Meter Reader	Meter Servicer	55
02/29/1988	Line Mechanic-A	Line Mechanic-A	42
03/29/2005	Line Mechanic-B	Line Mechanic-A	42
08/23/1978	Line Mechanic-A	Line Servicer	54
12/08/1983	Line Mechanic-A	Line Mechanic-A	46
05/16/1979	Technician Senior	Distribution Line Coordinator	50
02/27/1974	Customer Services Account Representative I	Customer Services Acct Representative I	57
08/28/1978	Customer Services Specialist	Field Revenue Specialist	53
05/15/1980	Technician Senior	Technician Senior	53
07/05/1994	Line Mechanic-A	Line Mechanic-A	45
06/24/1996	Line Mechanic-A	Line Mechanic-A	43
02/05/1980	Line Mechanic-A	Line Crew Supervisor - NE	52
09/11/2006	Line Mechanic-D	Line Mechanic-C	29
06/01/1985	Manager Distribution System	Director Distribution Region Operations	48
2/16/1998	Meter Reader	Distribution Dispatcher III	44
.8/24/1978	Distribution Dispatcher II	Distribution Dispatcher II	57
02/03/1969	Distribution Line Coordinator	Right Of Way Agent-Distribution	62
05/09/1990	Engineer I	Engineer I	43
04/02/1982	Meter Electrician-A	Meter Electrician-A	52
06/28/1976	Technician Senior	Technician Senior	64
02/16/1988	Line Mechanic-A	Line Crew Supervisor - NE	45
06/16/1980	Line Mechanic-A	Line Mechanic-A	53
06/19/1996	Line Mechanic-A	Line Mechanic-A	47
01/13/1986	Line Mechanic-A	Line Mechanic-A	53
03/09/1978	Line Area Servicer	Line Servicer	55
07/11/1988	Line Mechanic-A	Line Servicer	45
10/01/1984	Line Mechanic-A	Driver-Ground Worker	58
03/08/1979	Meter Electrician-A	Meter Electrician-A	54
09/16/1986	Line General Servicer	Line Servicer	48
08/27/1979	Line Mechanic-A	Line Servicer	54
06/14/1990	Line Mechanic-A	Line Mechanic-A	51
03/28/2005	Line Mechanic-B	Line Mechanic-A	45
05/16/1988	Meter Reader	Technician II	46
05/19/2008	Engineer IV	Engineer IV	28
12/17/1979	Technician Senior	Technician Senior	53
11/20/2006	Engineer III	Engineer III	43
03/23/1987	Meter Reader	Field Revenue Specialist	49
09/01/1988	Customer Services Specialist	Field Revenue Specialist	61
02/04/1970	Line General Servicer	Line Servicer	61
5/19/1980	Line Mechanic-A	Line Crew Supervisor - NE	50
1/09/1987	Line Mechanic-A	Line Mechanic-A	54
10/27/1980	Line Mechanic-A	Line Mechanic-A	49
02/27/1989	Line Mechanic-A	Line Mechanic-A	43
12/12/1966	Line General Servicer	Line Servicer	69
01/18/1978	Line General Servicer	Line Servicer	55
04/02/1979	Senior Clerk	Administrative Associate	62

ate of Hire	Employee Level Position Hired in At	Current Position	Current Age
09/17/1986	Distribution Line Coordinator	Supervisor Distribution Support	52
04/26/1984	Intermediate Clerk	Administrative Associate	52
01/01/1996	Lead Customer Solutions Associate	Administrative Associate	38
06/01/1989	T & D Clerk-A	Administrative Associate	49
09/09/1971	Customer Services Coordinator I	DSM Project Manager	62

Kentucky Power Company

REQUEST

Please describe the present on the job training process for the Company's distribution workforce.

RESPONSE

The Company has a variety of training curriculum depending on distribution job type. The most robust training curriculum is for the line/service mechanic. The AEP Line/Service Mechanic Training Program consists of nine levels, requiring 17 weeks of formalized training, spanning a period of four years. The first eight classes are each two weeks in duration. The final training session is one week in duration, including more than 175 modules. Testing and competency demonstrations are arranged through on-site instructors at any one of the AEP Training Centers. Class time and on the job training make up the 9000-hour training program. These same instructors also provide assistance during practice sessions; coordinate materials, ensure tool and equipment requirements are met; and evaluate and provide feedback on the trainee's progress based on satisfactory completion of course requirements and program materials.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Please quantify the savings that the Company will achieve if it increases its distribution workforce due to reductions in overtime, if any. In addition, please provide the amount of such savings included in the Company's revenue requirement.

RESPONSE

Increasing the distribution workforce will not lead to reductions in total overtime because overtime is driven primarily by environmental, weather and equipment conditions. However it will result in less overtime worked per employee. Therefore, the Company did not quantify any resulting savings in overtime.

WITNESS: Everett G Phillips

Kentucky Power Company

REQUEST

Refer to page 34 line 12 of Mr. Phillips' Direct Testimony wherein he claims that "Much of KPCo's electricity delivery system is 20 to 30 years old or older." Please provide a vintage dollar distribution for each distribution plant account.

RESPONSE

For the requested information, please see the attached page. Column E, or "Average Age (Yrs)" shows the average age of distribution plant-in-service by FERC account. This is determined by subtracting the depreciated amount from the average service life of the equipment. Taking this age information and averaging it across all distribution FERC accounts shows that the average piece of distribution equipment in service on the KPCo system is 24 years old.

WITNESS: Everett G Phillips

Kentucky Power Company
Depreciation Study as of December 31, 2009

A	B	C	D	E	F
FERC Account	FERC Account Description	Average Service Life (Yrs)	Average Remaining Life (Yrs)	Average Age (Yrs)	Plant In-Service 12/31/2009
361	Structures & Improvements	65	37	28	$ 4,274,452
362	Station Equipment	25	-	25	$ 61,525,439
363	Storage Battery Equipment	-	-		$ -
364	Poles, Tower & Fixtures	28	-	28	$ 155,658,070
365	Overhead Conductor & Devices	26	-	26	$ 140,897,608
366	Underground Conduit	37	9	28	$ 4,967,170
367	Underground Conductor	44	16	28	$ 7,975,566
368	Line Transformers	25	-	25	$ 101,447,711
369	Services	18	-	18	$ 41,328,640
370	Meters	27	-	27	$ 23,220,550
371	Installations on Customers Premises	11	-	11	$ 18,284,099
372	Leased Property on Cust. Premises	-	-		$ -
373	Street Lighting & Signal Systems	15	-	15	$ 2,978,968
					$ 562,558,273
	Average Age of Distribution Plant-In-Service			24	

Kentucky Power Company

REQUEST

Refer to line 7 of Exhibit DMR-4. Please provide the computations underlying the "Transmission Cost in Proposed Rates" of $49.514 million. Annotate this computation to the underlying spreadsheets for rate base, revenues and expenses and rate of return used by the Company to determine the revenue requirement.

RESPONSE

Please see Response to Staff 2nd Set Item No. 57a.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Refer to line 8 of Exhibit DMR-4 entitled "Transmission Adjustment." Please confirm that this adjustment should be made to the base revenue requirement if the Company's proposed TA rider is not approved. If this is not correct, then please explain why it is not correct.

RESPONSE

No. The Company's proposed Tariff T.A. is based upon the premise that KPCo customers should pay for transmission service based upon the charges assessed by PJM for such service. If this premise is not upheld through the implementation of Tariff T.A., then KPCo customers would continue to pay for transmission service based upon KPCo's average embedded costs.

WITNESS: David M Roush

Kentucky Power Company

REQUEST

Please provide a copy of the depreciation study and workpapers used to develop the existing depreciation rates.

RESPONSE

Refer to response to Commission Staff's First Set, Item No. 56.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Please provide the existing depreciation rates by plant account or the most detailed level for which they were approved.

RESPONSE

Refer to the direct testimony of Witness James E. Henderson, Volume 5, Exhibit JEH-1, Schedule II.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Please identify the Case No. in which the existing depreciation rates were approved and identify any differences in the rates approved by the Commission compared to the rates in the Company's depreciation study in that proceeding.

RESPONSE

The Company's existing rates were approved in KPCo Case No. 91-066. There were no differences in the rates approved by the Commission and the rates in the Company's depreciation study.

WITNESS: James E Henderson

Kentucky Power Company

REQUEST

Refer to page 3 of the Company's response to Staff 1-30. Please describe the amounts included in Associated Business Development and provide a listing of amounts included in the $1.490 million over $0.050 million.

RESPONSE

A description and listing of amounts included in Associated Business Development totaling $1.490 million are provided in the Company's response to Staff 1st Set Item No 30, pages 6 through 9, and include amounts above $500 dollars.

WITNESS: Ranie K Wohnhas

Kentucky Power Company

REQUEST

Refer to page 2 of the Company's response to Staff 1-29.

a. Please describe the plant additions to account 312 in the test year.

b. Please describe the plant additions to account 314 in the test year.

c. Please describe the plant additions to account 362 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

d. Please describe the plant additions to account 364 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

e. Please describe the plant additions to account 365 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

f. Please describe the plant additions to account 368 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

g. Please describe the plant additions to account 369 in the test year. Please quantify the plant additions and retirements due to storm events during the test year.

RESPONSE

See pages 2-4 of this response for a description of the plant additions.

The Company does not maintain the detail of plant additions and retirements associated with storm events separately from other plant additions and retirements. The Company follows the FERC Uniform System of Accounts (USA). The USA does not require KPCo to keeps its accounting records in this level of detail and KPCo has not kept its records in that level of detail.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Description of Plant Additions
For the Test Year October 1, 2008 Through September 30, 2009

Line No.	Funding Proj No.	Description	Amount
		31200 - Boiler Plant Equipment	
1	X00000002	WS-CI-KEPCo-G PPB	$5,622,846.74
2	000012426	Repl SSH Outlet T91 tubes	$5,493,121.48
3	BSU1CI002	Replace lower furnace U1	$4,603,672.04
4	BSU1CI001	Repl Secondary SH inlet U1	$2,400,286.58
5	BSU1CI006	Air Heater Basket Repl U1	$1,167,668.31
6	000013508	AOD & SCR Year Round Oper Rev	$912,976.93
7	BSU2CI013	BS2 Lwr Furnace Sidewall Rpl	($1,953.73)
8	BSPPBS235	South MainTurb Oil Cooler U2	($4,047.21)
9		Total Boiler Plant Equipment	$20,194,571.14
		31400 - Turbogenerator Units	
10	000012376	Big Sandy Unit 1 Turbine Retrofit	$33,809,312.29
11	X00000002	WS-CI-KEPCo-G PPB	$563,529.24
12		Total Turbogenerator Units	$34,372,841.53
		36200 - Station Equipment	
13	DP7KY014B	KY/Hitchins Rebuild Station	$2,944,308.81
14	DP7KY006B	KY/Soft Shell Sta 138-34kV	$2,403,806.33
15	DP7KY015B	KY/Busseyville Sta Add 2nd Xfm	$2,035,088.95
16	000012012	KYP-2006-2007 Relay Rehab Projects	$1,012,563.73
17	X00000646	ET-CI-KyPCo-T Drvn D Asset Imp	$491,194.23
18	000015593	DS/KYP/Metering Upgrade KY	$302,186.95
19	000013935	DS/KYPCO/Purchase-Rebuild Eq	$291,331.00
20	DP7KY121B	KY/Princess Station D20	$152,018.13
21	000016691	DS/KY/Replace&Refurbish	$136,103.80
22	X00000051	ED-CI-KEPCo-D AST IMP	$201.04
23	000011949	Circuit Breaker Rehab Program-KYP	($0.11)
24		Total Station Equipment	$9,768,802.86

Kentucky Power Company
Description of Plant Additions
For the Test Year October 1, 2008 Through September 30, 2009

Line No.	Funding Proj No.	Description	Amount
		36400 - Poles, Towers and Fixtures	
1	X00000073	ED-CI-KEPCo-D CUST SERV	$3,242,574.06
2	X00000692	KyPCo-D Service Restoration Bl	$1,745,539.25
3	X00000051	ED-CI-KEPCo-D AST IMP	$1,564,178.09
4	EDN014680	Ds-Kp-Ai Pole Replacement	$794,229.48
5	DP7KY121A	KY/Cannonsburg Distr Auto	$648,370.99
6	X00000716	KyPCo-D Third Party Work Blkt	$541,845.81
7	DP7KY006A	KY/Soft Schell Sta 34kV Fdrs	$509,124.11
8	DP7KY112A	KP/Beaver Ck Svc Black Diamond	$483,708.53
9	DP7KY103E	KY/Busseyville Sta Torchlight	$183,111.97
10	DP7KY015A	KY/Busseyville Sta Feeders	$159,893.08
11	DP7KY014A	KY/Hitchins Sta Relocate Fdrs	$102,731.52
12	DP7KY005A	KP/Salisbury Sta Feeder Impr	$38,627.36
13	DP8KY014A	KY/Collier Sta 34kV to Equitab	$19,617.17
14	EDN014720	Ds-Kp-Ai Recloser Replacement	$2,801.21
15	X00000704	KyPCo-D Small Cap Adds Blkt	$2,666.12
16	DR6CH068A	KY/Elwood Sta - Dorton Fdr Imp	$1,066.90
17	DP7KY103A	KY/Busseyville Sta Louisa Fdr	$742.72
18	DP7KY002A	KY/Beaver Creek Ligon Fdr	$0.02
19	X00000095	ED-CI-KEPCo-D PPR	($241,233.75)
20		Total Poles, Towers and Fixtures	$9,799,594.64
		36500 - Overhead Conductors and Devices	
21	000009160	KP/2004-2006 R/W Widening	$3,943,808.68
22	X00000073	ED-CI-KEPCo-D CUST SERV	$2,361,019.27
23	X00000692	KyPCo-D Service Restoration Bl	$2,250,630.16
24	EDN014720	Ds-Kp-Ai Recloser Replacement	$1,863,145.41
25	X00000051	ED-CI-KEPCo-D AST IMP	$1,513,624.37
26	X00000716	KyPCo-D Third Party Work Blkt	$789,524.50
27	DP7KY006A	KY/Soft Schell Sta 34kV Fdrs	$702,396.53
28	000016528	KY/Cutout-Arrester 2008-9	$375,528.89
30	DP7KY112A	KP/Beaver Ck Svc Black Diamond	$360,074.50
31	DP7KY103E	KY/Busseyville Sta Torchlight	$288,121.02
32	EDN014680	Ds-Kp-Ai Pole Replacement	$252,983.77
33	DP7KY015A	KY/Busseyville Sta Feeders	$169,360.50
34	DP7KY014A	KY/Hitchins Sta Relocate Fdrs	$156,961.91
35	DP7KY121A	KY/Cannonsburg Distr Auto	$138,121.06
36	DP7KY005A	KP/Salisbury Sta Feeder Impr	$68,301.12
37	DP8KY014A	KY/Collier Sta 34kV to Equitab	$13,771.00
38	X00000704	KyPCo-D Small Cap Adds Blkt	$4,004.12
39	DP7KY002A	KY/Beaver Creek Ligon Fdr	($0.02)
40	DP7KY103A	KY/Busseyville Sta Louisa Fdr	($794.04)
41	DR6CH068A	KY/Elwood Sta - Dorton Fdr Imp	($1,516.65)
42	X00000095	ED-CI-KEPCo-D PPR	($207,511.32)
43		Total Overhead Conductors and Devices	$15,041,554.78

Kentucky Power Company
Description of Plant Additions
For the Test Year October 1, 2008 Through September 30, 2009

Line No.	Funding Proj No.	Description	Amount
		36800 - Line Transformers	
1	X00000084	ED-CI-KEPCo-D LN TRNSF	$3,416,114.54
2	X00000051	ED-CI-KEPCo-D AST IMP	$594,198.01
3	X00000692	KyPCo-D Service Restoration Bl	$589,550.85
4	X00000073	ED-CI-KEPCo-D CUST SERV	$552,198.29
5	000016528	KY/Cutout-Arrester 2008-9	$488,320.94
6	DP7KY121A	KY/Cannonsburg Distr Auto	$180,541.06
7	DP7KY112A	KP/Beaver Ck Svc Black Diamond	$147,197.08
8	DP7KY103E	KY/Busseyville Sta Torchlight	$131,093.20
9	DP8KY014A	KY/Collier Sta 34kV to Equitab	$112,094.35
10	X00000716	KyPCo-D Third Party Work Blkt	$73,418.44
11	EDN014680	Ds-Kp-Ai Pole Replacement	$51,634.13
12	DP7KY006A	KY/Soft Schell Sta 34kV Fdrs	$28,273.89
13	X00000704	KyPCo-D Small Cap Adds Blkt	$24,303.29
14	DP7KY014A	KY/Hitchins Sta Relocate Fdrs	$2,960.44
15	EDN014720	Ds-Kp-Ai Recloser Replacement	$1,953.56
16	DP7KY015A	KY/Busseyville Sta Feeders	$1,832.74
17	DP7KY005A	KP/Salisbury Sta Feeder Impr	$696.15
18	DR6CH068A	KY/Elwood Sta - Dorton Fdr Imp	$537.64
19	DP7KY103A	KY/Busseyville Sta Louisa Fdr	($1.81)
20	X00000095	ED-CI-KEPCo-D PPR	($8,094.10)
21		Total Line Transformers	$6,388,822.69
		36900 - Services	
22	X00000073	ED-CI-KEPCo-D CUST SERV	$2,643,440.23
23	X00000692	KyPCo-D Service Restoration Bl	$953,116.19
24	X00000051	ED-CI-KEPCo-D AST IMP	$75,951.90
25	X00000716	KyPCo-D Third Party Work Blkt	$23,961.77
26	EDN014680	Ds-Kp-Ai Pole Replacement	$9,041.97
27	DP7KY112A	KP/Beaver Ck Svc Black Diamond	$2,062.51
28	DP7KY006A	KY/Soft Schell Sta 34kV Fdrs	$1,876.12
29	X00000095	ED-CI-KEPCo-D PPR	$894.85
30	DR6CH068A	KY/Elwood Sta - Dorton Fdr Imp	$706.54
31	DP7KY014A	KY/Hitchins Sta Relocate Fdrs	$247.24
32		Total Services	$3,711,299.32

Kentucky Power Company

REQUEST

Refer to the Company's response to Staff 1-12, page 7 of 19.

a. Please explain all reasons why FERC Account 593, Maintenance of Overhead Lines, increased by $13.411 million for the 12 months ended September 30, 2009 compared to the 12 months ended September 30, 2008.

b. Please provide the annual amounts booked to FERC Account 593, Maintenance of Overhead Lines for each calendar year from 2004 through 2008 and each 12 months ended September 30, 2004 through 2008.

c. Please indicate whether the Company included a proforma adjustment in its filing to normalize costs booked during the test year to FERC Account 593, Maintenance of Overhead Lines. If so, identify the proforma adjustment in the filing. If not, explain in detail why the Company did not include a proforma adjustment for this purpose.

d. Please indicate whether the Company considers the increase of $13.411 million in FERC Account 593 a recurring level of expense. If so, please explain in detail why this amount or some subset of this amount is recurring.

RESPONSE

a. Other than the normal day to day activities of maintaining overhead lines, the increase of $13.411 million in FERC account 593, Maintenance of Overhead Lines from the 12 months ended September 30, 2008 to the 12 months ended September 30, 2009 is primarily due to significant storm restoration expenses related to severe storms in January 2009, February 2009 and May 2009.

b. The annual amounts booked to FERC Account 593, Maintenance of Overhead Lines for each calendar year from 2004 through 2008 and each 12 months ended September 30, 2004 through 2008 are as follows:

Calendar Year Ended:	Amount
2004	$ 13,965,041.89
2005	11,851,456.39
2006	14,024,573.23
2007	14,372,082.91
2008	15,612,653.87

12 Months Ended September 30:	Amount
2004	$ 13,282,201.40
2005	12,062,182.15
2006	14,052,195.08
2007	14,138,828.44
2008	16,003,896.72

c. Yes. Please see Section V, Workpaper S-4, Page 15 of the filing. In responding to this data request we discovered an error in the original filing. We inadvertently inserted the current storm amount in base rates in column 3, line 1 versus the actual amount for the 12 month ended period 9/30/09 of $12,423,094 . Please see page 2 of this response for a corrected Section V, Workpaper S-4, Page 15.

d. The Company believes that some portion of the increase to FERC Account 593 is a recurring level of expense as shown by a three year average on Line 5 of the corrected Section V, Workpaper S-4, Page 15 attached as page 3 of this response.

WITNESS: Ranie K Wohnhas

Kentucky Power Company
Normalization of Major Storms Adjustment
Test Year Twelve Months Ended 9/30/2009

Section V
Workpaper S-4
Page 15
Revised 2/12/10

Ln No (1)	Description (2)	Storm Damage Expense Excl. In-House Labor (3)	Constant Dollar Index [1/] (4)	Expense in 2009 Dollars (5)
1	12 ME September 30, 2009	$12,423,094	1.00	$12,423,094
2	12 ME September 30, 2008	$51,497	1.03	$53,042
3	12 ME September 30, 2007	$461,822	1.18	$544,950
4	Three Year Total Storm Damage			$13,021,086
5	Three Year Average (Ln 4/ Ln 3)			$4,340,362
6	Test Year Storm Damage Expense			$12,423,094
7	Adjustment to O&M for Storm Damage Normalization			($8,082,732)
8	Allocation Factor - GP-TOT			0.991
9	KPSC Jurisdictional Amount (Ln 7 X Ln 8)			($8,009,987)

[1/] Handy-Whittman Contract Labor Index
Reference E-2 Line 42

January, 2009	535
January, 2008	518
January, 2007	453

Witness: R. K. Wohnhas